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Sand Production during Improved Oil Recovery in Unconsolidated Cores

Mohammad A. J. Ali.
Kuwait Institute for Scientific Research

S. M. Kholosy
Kuwait Institute for Scientific Research

A. A. Al-Haddad
Kuwait Institute for Scientific Research

K. K. Al-Hamad
Kuwait Oil Company

***Abstract* – Steam injection is a mechanisms used for improved oil recovery (IOR) in heavy oil reservoirs. Heating the reservoir reduces the oil viscosity and causes the velocity of the moving oil to increase; and thus, the heated zone around the injection well will have high velocity. The increase of velocity in an unconsolidated formation is usually accompanied with sand movement in the reservoir creating a potential problem. Core samples from different wells in Kuwait were used to examine sand production during thermal injection in unconsolidated formation. A reservoir condition coreflood apparatus was used to inject oil with viscosities and flowrates. The oil sample was heated to give different viscosities, and the flowrate was increased gradually at each viscosity to establish the critical flowrate for sand production. At the end of the each test, the produced oil containing sand were filtered for sand content.**

The result showed that sand compaction at the injection face was more significant than sand production. Sand compaction resulted in permeability decline, whereas sand production improved the permeability. Sand production is a function of fluid and formation properties. The critical flowrate varied from 6 to 401 cc/hr for grain diameter of 277 to 366 µm, and at 684 cp viscosity oil. The critical flowrate varied from 3 to 87 cc/hr for grain diameter of 277 to 366 µm. Flowrate and viscosity of the oil, and the formation porosity, grain size, grain sorting, cementation, and overburden pressure, all contribute to sand production. Modeling all of these properties to predict sand production remains to be very challenging.

***Keywords* — Critical flowrate, sand production.**

I. Introduction

Improved oil recovery for heavy oil reservoirs is becoming a new research study for Kuwaiti reservoirs. There are two mechanisms for improved oil recovery by thermal methods. The first method is to heat the oil to higher temperatures, and thereby, decrease its viscosity for improved mobility. The second mechanism is similar to water flooding, in which oil is displaced to the production wells. While more steam is needed for this method than for the cyclic method, it is typically more effective at recovering a larger portion of the oil.

Steam injection heats up the oil and reduce its viscosity for better mobility and higher sweep efficiency. During this process, the velocity of the moving oil increases with lower viscosity oil; and thus, the heated zone around the injection well will have high velocity. The increase of velocity in an unconsolidated formation is usually accompanied with sand movement in the reservoir creating a potential problem. The objective of this study was to estimate the critical flowrate of sand production in heavy oil reservoir that is subjected for thermal recovery process.

Sand production can be defined as the production of sand particles dislocated and detached from the reservoir matrix along with the produced hydrocarbon to the surface. Sand production is a very challenging and a complex problem, which has troubled the oil industry worldwide. Millions of dollars are spent every year on cleaning out sand from wells, surface facilities, and wellbore. Sand production from highly unconsolidated formation can occur as soon as the well brought to production. However, in more consolidated sandstone formation, sand production occurred initially for short periods then was decrease and eventually stopped.

A study by Musaed et. Al. (2005) on unconsolidated cores where he introduced a sand production capability factor. He postulated that the capability factor is a function of overburden stress at any given two points. He observed that overburden stress highly affects sand production at different flowrates. He also noted that sand production from the yielded zones around vertical wells is higher than that in the horizontal well. Another study by De-Hua et. Al. (2007) claiming that a simple universal model for predicting critical velocity of sand production in heavy oil reservoirs is unrealistic at this stage. Generally, several factors affecting sand movement due to fluid velocity such as rock texture pore fluid properties, and interaction between pore fluids and rock matrix at different temperatures. Their analysis showed that sand could be either oil-wet or water-wet. For water-wet sand, oil is a detached pore fluid and does not withstand overburden pressure. For oil-wet sand, the oil in pore fluid is directly contacted with the free sand. The amount of sand movement varies with radial distance around the wellbore, i.e. maximum concentration of sand is near the wellbore radius. Sand movement occurs when the drag forces of the moving fluid exceeds the body forces holding the detached sand in place.

II. Experimental Procedure

An automated high-pressure and temperature, closed-capillary tube was used to measure oil viscosity at 25, 100, and 180 ^{o}C to yield viscosity of 684, 16, and 0.74 cp, respectively. These temperatures were used to represent field condition during steam injection.

A reservoir-condition bench top core flood apparatus was used for this study. The coreholder and the oil accumulator were separately wrapped with heating jackets and temperature control unit. The initial setup was conducted by placing the core sample inside the core holder and gradually applying a 600 psi overburden pressure before starting the injection. It was observed that while building the overburden pressure, sand was produced at the outlet production line. In some cases, too much sand was produced and the rubber sleeve was ruptured causing termination of the test. In some samples, the cores were deformed causing a leak from overburden fluid into the core and damaging the test. Ideally, it is preferred to install a backpressure regulator (BPR) in a typical core-flooding test. However, for this particular study, it was not advised to use it as it would trap sand grains inside the tubes and cause high differential pressure that would terminate the experiment. Therefore, it was decided not to use backpressure regulator and allow sand grains to produce from the core sample.

An alternative procedure was carried out by maintaining a minimum of 200 psi difference between the overburden pressure and injection pressure by manually adjusting the overburden pressure during the test. The 200 psi was used to represent reservoir pressure. At the start of the test, a one-way valve was placed at the exit outlet flow line in order to pressurize the pore-pressure. Starting a flow of 1 cc/hr, the pore pressure was gradually increased to reach to 50 psi, and kept at a constant pore-pressure and at 250 psi overburden pressure for overnight. Then, the outlet valve was slowly open with extreme care to prevent a sudden pressure drop and sand movement. Once the outlet valve is fully open, then the injection was started at low flowrate and gradually increases it while maintaining a constant overburden pressure. This procedure was also very challenging to conduct, as it was very difficult to maintain a constant net overburden pressure during varying the flow rates.

Applying and maintaining a constant overburden pressure was very challenging. The core plugs were deforming from their original size, and sand was compacting just by applying overburden pressure of 600 psi. Even when overburden pressure was applied very slowly, it required one to two hours for pressure stability. In some cases, the rubber sleeve was damaged, and core was collapsed due to overburden pressure.

Initially, the system and oil were heated to give low viscosity oil injection at constant flow rate until baseline permeability was established, or sand production was achieved. Later, the temperature was reduced to give higher viscosity oil, and was injected. Different flowrates were used ranging from 6 to 360 cc/hr, to inject for approximately 30 ml of oil (1 pore-volume) for each flowrate.

Oil samples containing sand coming out from the outlet of the cores were collected in glass beakers. The oil samples were cooled to room temperature, and the weight of the oil containing sand was measured. Then, a 100 ml of toluene was added to the oil and filtered with a 0.42-µm filter paper. The remaining sand and oil in the beaker were rinsed with toluene for complete removal of any residue. The weight of the dry filter paper was measured and labelled with the sample name. The weight of the sand was calculated by subtracting the weight of the dry sand with filter paper from the weight of dry filter-paper. The core samples were cleaned with toluene and subjected to grain size distribution by using manual sieving, unfortunately, the amount of produced sand was relatively too small for sieving.

III. RESULTS AND DATA ANALYSIS

The results from the initial laboratory setup indicated several phenomena in most core plugs. First, sand was produced in all samples, except for the very low permeability plugs. Most unconsolidated plugs were deformed when applying overburden pressure causing sand production even without fluid displacement. It appeared from these laboratory experiments that the major problem was anticipated by sand compaction at the injection face, which causes severe permeability damage, high upstream pressure, and sand production at each flowrate did not always increase with higher flowrates. In some cases, wormholes were formed due to high flowrate and compacted sand. Permeability values measured by the coreflood test were unrepresentative to the actual field permeability data because of the non-cylindrical deformation during the test. The reduction in the cross sectional area (diameter) along the length of the core caused uneven velocity as shown in Fig. 1.

Fig.1. Deformed core showing squeezed diameter at the outlet causing uneven velocity.

Measurement of sand production was very challenging in all core samples. The main challenge was by maintaining a stable and constant overburden pressure without using backpressure regulator for the unconsolidated cores. Sand was produced at the start of the test just by applying overburden pressure. The production of sand was not always increasing with flowrate. As can be seen in Figs. 2, low concentrations of sand were produced at all flowrates, but sand production did not always increased monotonically with flowrate.

The cumulative sand production was used to correlate between sand production and flowrate. The assumption was that using the cumulative sand production data, it is possible to back calculate sand production at any given flowrate. When a low viscosity oil of 0.74 cp was injected, there was a different sand production trend at different flowrate.

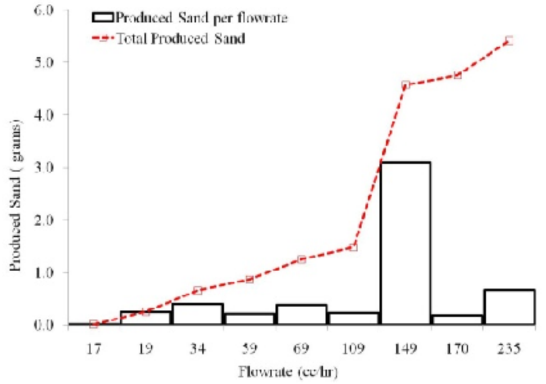

Fig.2. Sand production at different flowrates

The maximum sand production was seen at 289cc/hr, and lower sand production was observed at 333 and 360cc/hr. as illustrated in Table 1. Due to the limitation of this publication, only few samples are presented in this paper to illustrate the results and discus the challenges. It is believed that the reason for sand flocculation in these experiments was not enough sand to be produced after each flowrate and the experiments. The conclusion is that in order to improve the quality of the test, a new core must be used for each flowrate and viscosity. This however would require a large number of core samples and tests, which may not be feasible.

Table1. Estimation of critical flowrate of sand movement

Test No.	ϕ (%)	Produced Sand (%)	D_g µm (%)	Sorting (s) (%)	Lithology (%)	Critical Fliwrate (cc/hr) 0.74 (cp)	16 (cp)	684 (cp)
1	42	10	302	0.23	Very well sorted		148	
2	47	12	338	0.13	Very well sorted	174	48	24
3	47	16	277	0.57	Moderately well sorted	218	95	56
4	51	2	270	0.79	Moderately sorted			
5	48	25	289	0.86	Moderately sorted	243		
6	40	1	258	1.12	Poorly sorted			
7	48	3	327	0.67	Moderately well sorted			
8	52	12	365	0.67	Moderately well sorted	60	6	3
9	46	7	374	0.82	Moderately sorted	61		
10	41	5	472	0.66	Moderately well sorted	154		
11	42	9	363	0.62	Moderately well sorted		364	
12	44	9	337	0.53	Moderately well sorted		202	
13	48	19	306	0.45	Well sorted	850	91	25
14	32	0	278	0.93	Moderately sorted			
15	37	0	292	0.85	Moderately sorted			
16	62	1	316	0.64	Moderately well sorted			178
17	44	0	307	0.53	Moderately well sorted			
18	57	32	369	0.72	Well sorted			
19	47	0	326	0.56	Moderately well sorted			
20	43	0	162	0.64	Moderately sorted			
21	44	0	231	0.70	Moderately sorted			

ϕ : Porosity

Produced Sand %: Weight of produced sand / weight of whole core

$\overline{D}_g$: Average grain size distribution, µm.

s: Grain sorting by Simon J. Blott, and Kenneth (2001).

A plot of flowrate vs. the cumulative sand production gives a semi linear fit that describes the general behavior of sand production as shown in Figs 3-5. Different trends of sand production for core samples were found with grain size distribution and viscosities.

Although, by theory it is expected to see less sand production with low viscosity oil, but this was not always true. The cumulative sand production was increasing with flowrate, but there was not a clear trend. For example, Fig. 3 shows a low viscosity oil of 0.74 cp produced more sand than the higher viscosity oils. Fig. 4 shows systematic sand production; where low viscosity oil produce less sand, until a flowrate of 150 cc/hr when sand production sharply increased. Fig. 5 shows high viscosity oil of 684 cp produced less sand than at lower viscosity oil. These observations suggest that other parameters such as sand consolidation and cementing, grain sorting (s) in addition to oil viscosity could affect sand movement and production. Other factors that are worth investigation, such as grain shape, grain density, rock compressibility, and clay type could be functions of sand movement.

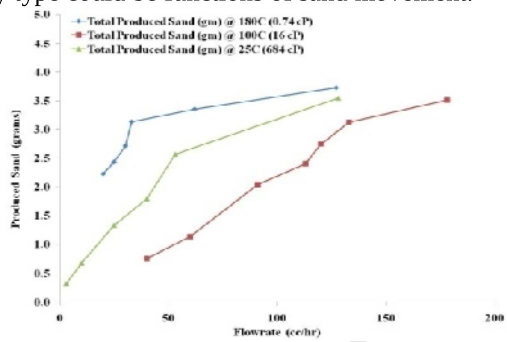

Fig.3. Sand production for $\overline{D}_g$ of 306 µm

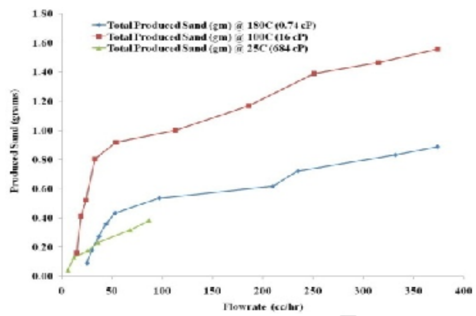

Fig.4. Sand production for $\overline{D}_g$ of 327 µm

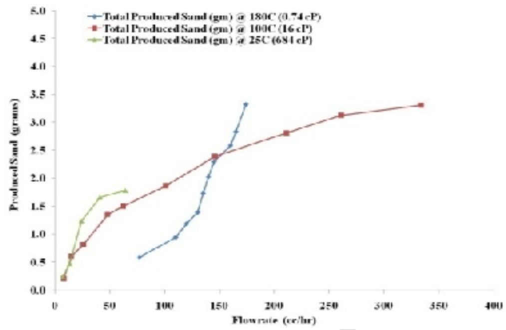

Fig.5. Sand production for $\overline{D}_g$ of 338 µm

Fig. 6 shows the total sand production during oil injection with different viscosities for the same cores. The general trend seemed at first to show higher sand production was seen with the small average grain diameter $\bar{D}_g$ cores than the large grain size cores. However, a sample with $\bar{D}_g$ of 207µm showed less sand production than a core with higher grain size. This indicates that sand production is unlikely to occur with low permeability. Small grain diameter cores produced sand at lower flowrates than the larger grain diameter cores. Large size particles require higher drag force to move through the pore channel than smaller size particles. High viscosity oil tended to produce more sand than low viscosity oil.

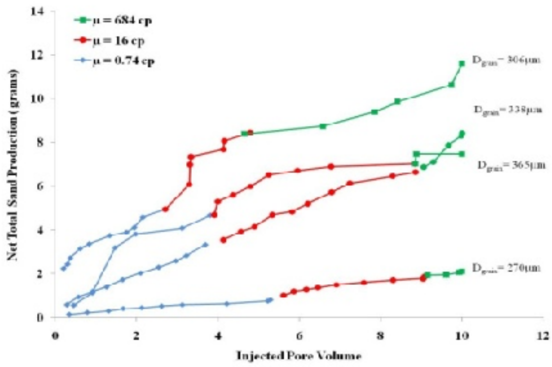

Fig.6. Net total sand production using different viscosity oil

The initial observation suggested that other factors affecting sand production in addition to flowrate and viscosity. Therefore, the porosity, average grain size distribution, and grain sorting where imperially correlated with permeability to give a linear relationship as shown in Fig. 7. This concludes that permeability is dejectedly proportional to porosity, grain diameter, and grain sorting. Hence, higher grain size and porosity anticipated with well sorted grains give high permeability values. Grain sorting by Simon J. Blott, and Kenneth (3) is presented in Table 3.

$$K(mD)\ \square\ \square\ \frac{\bar{D}_g}{s} \quad (1)$$

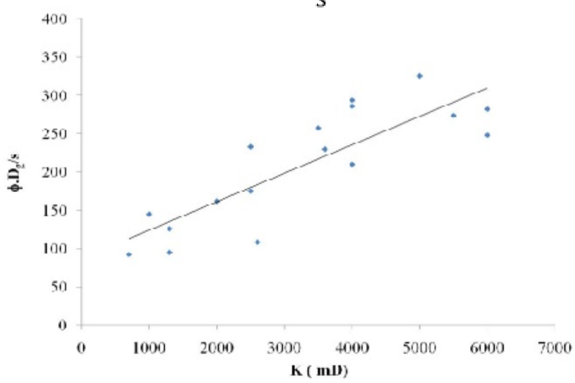

Fig.7. Affect of porosity, grain size, and sorting on permeability.

Table 3. Grain Sorting Distribution

s	Sorting Type
<0.35	Very well sorted
0.35-0.5	Well sorted
0.5-0.7	Moderately well sorted
0.7-1	Moderately sorted
1-2	Poorly sorted
2-4	Very poorly sorted
>4	Extremely poorly sorted

The above correlation was used to correlate between permeability, porosity, average grain size distribution, and grain sorting with the produced sand ratio which is the weight of the produced sand divided by the total weight of the core sample. The results in Fig. 8 show that sand production was also a function of the degree of consolidation. Although all samples were collected from unconsolidated formation, but some cores were sand rubles, others were friable, and some were moderately consolidated.

The analysis suggests that the unconsolidated formation is more prompt to sand production than consolidated formation. Sand grain that are not well cemented and loose have high probability to move in the formation. This hypothesis explains the ambiguity of the data. Hence, it makes more sense to consider cementation factor and rock compressibility for future work to improve the data interpretation for simulation modeling. Unfortunately, the lack of enough samples limited additional experiments.

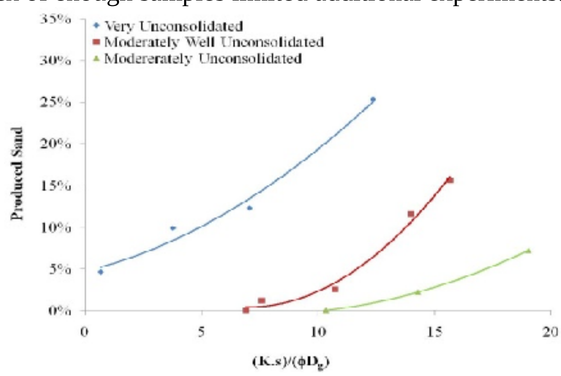

Fig.8. Affect of sand unconsolidation on sand production

Critical flowrate was more significant to low viscosity oil than at high viscosity oil. At 0.74 cp viscosity oil, the critical flowrate varied from 60 to 850 cc/hr for grain diameter of 277 to 366 µm, and at 16 cp. The critical flowrate varied from 6 to 401 cc/hr for grain diameter of 277 to 366 µm, and at 684 cp viscosity oil. The critical flowrate varied from 3 to 87 cc/hr for grain diameter of 277 to 366 µm. Fig. 9 shows an illustration of the change of velocity along the length of the core plug inside the coreholder

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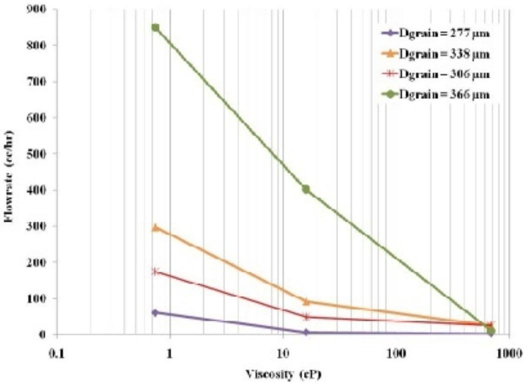

Fig.9. Correlations between oil viscosity and critical flowrates for different grain size.

The analysis of the experimental data concludes that weakly consolidated reservoir rocks usually have the desirable properties of high porosity, permeability, and grain size. However, small particles and sand grains usually are dislodged and carried along with the flow of water and oil. This sand production phenomenon may reduce the formation permeability when particle bridging occur, or increase the permeability when they are produced to the surface.

Therefore, understanding sand movement and production phenomena in a reservoir would help and assist in designing an optimum thermal injection method. The laboratory results of this study suggest that, both sand compaction at the injection face, and sand production at production streamline are possible mechanisms.

Hence, our hypothesis is that during steam injection, where the steam is more effective near the wellbore radius, giving the oil low viscosity and high velocity, then it is most likely that sand compaction at the injection wells to occur, but an increase of pressure at the injection wells could occur as a result of sand compaction and permeability decline. Similar work have been carried out by Maurice (2000) where he suggested that while the injection wells are several feet away from the production well, it is expected to see no or low sand production at the producing well.

However, in a cyclic steam injection, the low oil viscosity and high velocity near the wellbore radius could result in sand production and increase in permeability. But the production of sand to surface could erode the flow lines and other production facilities.

Unfortunately, mechanical and chemical remedial actions such as screeners , chocks, and polymers, usually reduce production of sand and oil. Therefore, understanding of how, when, and where sand is movement and production is necessarily for implementing a successful improved oil recovery technique, and also required for simulation and modeling software. Unfortunately very little publication is available in the literature for this subject and therefore it is not feasible to compare the results and data analysis.

IV. Conclusion

The results obtained from these coreflood experiments gave an insight into field application, but it were not conclusive. Dealing with unconsolidated cores in laboratories is extremely crucial and very challenging. Therefore, depending on the core flooding experiment alone in characterizing the reservoir is very dangerous and the validity of the setups remains to be questionable.

- The unconsolidated plugs were deformed due to overburden pressure, which resulted in sand production.
- Sand compaction reduced core permeability at the injection face, where as sand production at the outlet increased permeability.
- Sand production from unconsolidated formation could be affected by flowrate, fluid viscosity, and grain diameter.
- Large grain diameter has higher critical flowrate than smaller grain diameter.

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Author's Profile

Dr. Mohammad A. J. Ali

is a research associate works at Kuwait Institute for Scientific Research (KISR). He has a Ph.D. from Delft University in the Netherlands, M.Sc. from Colorado School of Mines, and B.Sc. from Marietta College, all in petroleum engineering. His main research areas are in special and routine laboratory core analysis. Ali carried out several laboratory studies of formation damage due to water injection, water compatibility issues, and asphaltene precipitation. Most of his experiences are related to the research and technology group at Kuwait Oil Company (KOC).