EVALUATION OF LOW-SALINITY WATERFLOODING FOR 51 FIELDS IN WYOMING

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ABSTRACT

This report evaluates the effectiveness of low-salinity flooding in the Minnelusa Formation in the Powder River Basin of Wyoming. The Minnelusa sandstone play constitutes a resource of several hundred fields with cumulative production of more than 600,000,000 barrels of oil. Currently there are 130 Minnelusa fields that are in active waterflood.

Fifty-five are flooded with low-salinity water, 52 with mixed salinity water and 23 with formation brine. Recovery factors for 51 fields were compiled and used as the primary metric to evaluate the effectiveness of low-salinity waterflooding. A second metric used was normalized production versus % oil cut, which is independent of recovery factor. Neither metrics showed any increased production for the fields that used low-salinity injection compared to fields flooded with reservoir brine or mixed water.

In the field cases studied, the low-salinity injection water was derived from wells in the shallow Lance and Fox Hills Formations, which have an average salinity of 2100 ppm, while the Minnelusa fields had initial formation water salinity ranging from 1134 to 261,000 ppm. Some fields studied did not have sufficient salinity reduction because injected salinity was very similar to formation water salinity. In other cases where there was sufficient dilution there was still no increase in oil production. Dilution factor was expressed as salinity ratio to allow direct comparison of all fields. Regardless of dilution, there was no apparent trend of increasing recovery with lower salinity injection.

1. INTRODUCTION

Low-salinity waterflooding has been widely studied during the last decade by various research groups as one of the most inexpensive methods of enhanced oil recovery (EOR). The level of investigation into low-salinity waterflooding has sharply increased in the past three years as more research groups have become involved (Morrow and Buckley, 2011). Laboratory studies with synthetic formation water, reservoir and outcrop rocks and reservoir oil are injected with water diluted by a factor ranging from 10 to 100-fold compared to formation waters. Many studies have confirmed that this method can increase the recovery the lab scale by 2-30% original-oil-in-place (OOIP) depending on the brine composition, crude oil composition and rock type used. However, while both laboratory and field studies have had successful results, there are examples in which low-salinity flooding does not create additional production (Sharma and Filoco, 2000, Rivet et al 2010).

A limited number of field examples using low-salinity floods have also been reported in the EOR literature with mixed results (Seccombe et al., 2010, Skrettingland et al., 2010). These field examples have been confined to single fields, or several adjacent fields. The Minnelusa Formation in Wyoming offers a much larger dataset. Previously, Robinson (2007) used data from three Minnelusa fields and found that that injection of low-salinity water into Minnelusa fields produced improved recovery during early production. Towler and Griffith (1998) used data production data from 20 Minnelusa fields, 19 of which were flooded with low-salinity water. They concluded that the fields flooded with low-salinity water had higher recoveries compared to the single normal waterflood.

Low-salinity waterflooding was not performed as an EOR technique, but instead the low salinity water from shallow sands was used for reasons of low lifting and conditioning costs (Towler and Griffith, 1998). The Minnelusa fields are generally small (<10MMBO OOIP) with 10 or less wells. Primary production is small and waterflooding began early in field histories. Minnelusa fields have a wide range of oil gravity, OOIP, initial oil saturation and net pay, all factors that may influence recovery. Analysis of variation in recovery factor as a function of API gravity, OOIP, initial saturation, net pay, number of wells, permeability, porosity, well spacing, duration of flooding, and depth showed no correlation to recovery for fields with either low salinity or saline waterfloods (Thyne et al. 2009).

Wyoming Oil and Gas Conservation Commission (WOGCC) records include waterflood application date and the source formation for the injection water. We provisionally classified fields as saline (waterflooded with formation water), mixed (combination of formation and low-salinity water) and low-salinity (injection water from the Lance or Fox Hills formations). Based on this classification, 55 fields are low-salinity, 52 mixed salinity and 23 saline.

2. PROCEDURES

2.1 Data

The USGS and WOGCC databases were queried for the chemistry of Minnelusa, Lance and Fox Hills Formations water chemistry data. The samples selected were either drill stem tests (DST) or produced water samples with charge balance values of <±10%. Sample temperatures were calculated based on the perforated interval and the geothermal gradient derived from WOGCC DST data. Minnelusa formation water salinity ranges from 1134 to 261,982 ppm with Na-Cl-Ca-SO_4water chemistry. Salinity is strongly dependent on location; lower salinity water is found in the northeast basin with increasing salinity to the southeastern. In contrast, the Lance and Fox Hills Formations, the source of the low-salinity injection water, has lower TDS, (300 to 6000 ppm) and Na-HCO_3 chemistry.

We calculated the recovery factor for Minnelusa fields that had oil and water production, total pore volume and OOIP were reported (Towler and Griffith, 1990, Hochanadel et al., 1990, Mack and Duvall, 1990). Fields with recovery factors less than 30% and greater than 80% were removed from further analysis leaving 51 fields with sufficient data. The recovery factors for the 51 fields ranged from 30% to 70% and are normally distributed with a mean of 52%.

3. RESULTS

3.1 Preliminary Analysis of Data

The preliminary evaluation was conducted by comparing the average recovery factors of various groups of fields (Table 1). The average recovery for all fields is 52.4% OOIP, fields with low salinity injection 52.2%, and 52.6% OOIP for fields with saline injection (saline + mixed). The data from 20 fields without any polymer treatment show no difference in average recovery factor for fields with low-salinity injection (50.8%) compared to saline injection (51.4%). The difference in average recovery factors between fields that had polymer treatment and low salinity injection (54.7%) compared to fields with polymer and saline injection (52.9%) is also very small.

Table 1. *Average value for recovery factor for Minnelusa Fields.*

Category	%OOIP$_{2008}$	n
All fields	52.4	51
Low Sal	52.2	25
Saline	52.6	26
All WF (no polymer)	50.9	20
Saline WF	51.4	4
Low sal WF	50.8	16
All polymer	53.4	31
Saline polymer	52.9	22
Low sal polymer	54.7	9

3.2 Quantification of Dilution

Some Minnelusa fields have fairly fresh formation water and injection of Lance-Fox Hills water may not provide significant dilution. Dilution was quantified by using the salinity ratio, defined as the ratio of salinity of injected water to salinity of formation water, to better evaluate field performance (Robinson, 2007). The results for 51 fields are plotted in Figure 1. For calculation purposes mixed injection water were assumed to have salinity equivalent to a 50:50 mixture of low-salinity source and formation water. For cases without low-salinity and formation water chemistry, we used the average TDS of the Lance and Fox Hills (2100 mg/L) and estimated Minnelusa formation water TDS.

The data include fields that were waterflooded with formation water (salinity ratio =1), fields waterflooded with a mixture of low-salinity and formation water (salinity ratio around 0.3-0.7) and fields waterflooded with low-salinity water (salinity ratio between 0.006 and 0.2). This study has sufficient saline waterfloods to establish a baseline (Towler and Griffith, 1998). The range of recovery factors for fields with dilution factors is almost exactly the same for all three groups with no correlation between degree of dilution and recovery.

3.3 Water Breakthrough Evaluation

Calculated recovery factors are based on the reported OOIP, reservoir pore volume and current production data. All three values have some uncertainty. The largest uncertainty is in the reported OOIP and reservoir pore volumes. These values were taken from WOGCC records of unitization hearings with estimated OOIP was based on either material balance or volumetric calculations. Therefore, we used a metric independent of recovery factor to further evaluate low-salinity injection performance.

Minnelusa fields typically produce high oil cuts until water breakthrough, usually between 0.4 and 0.6 pore volumes, after which % water rapidly increases from 5% to 90+%. Robertson (2007) noted that Minnelusa fields flooded with low-salinity water had better early performance. Therefore, we assume that breakthrough will be later (higher values) for fields with benefits from low-salinity injection. Water breakthrough was defined as the point where oil cut sharply declined (or water cut sharply increased) on a plot of normalized cumulative production versus % oil cut. Yearly cumulative production was normalized for each field by using yearly cumulative oil divided by 2008 cumulative production. This analysis was restricted to fields with complete production history (19 fields). Table 2 lists the breakthrough points for fields with low-salinity injection (8) and those with mixed or formation water injection (11).

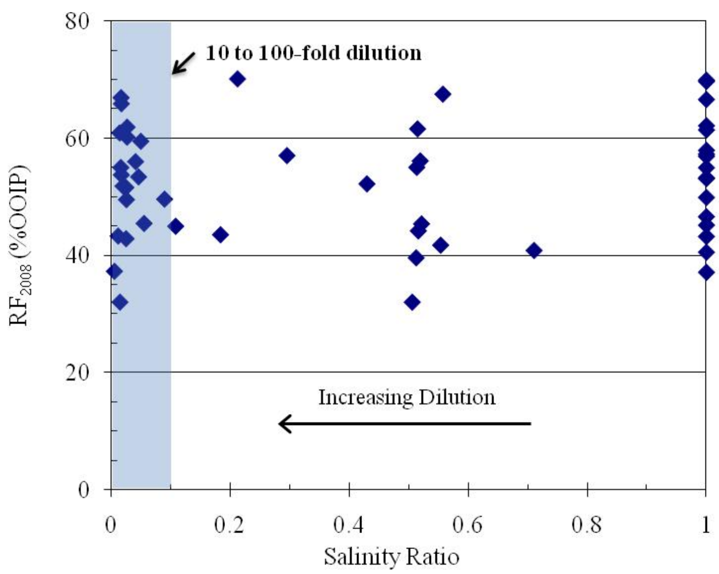

Figure 1. Salinity ratio versus recovery factor for 51 Minnelusa fields. Dilution factor of 1 is for fields with no dilution (injection of formation water), shaded area highlights fields with 10 to 100-fold dilution.

4. DISCUSSION

4.1 Evaluation of Low Salinity Flooding in the Minnelusa

Pu et al. (2010) reported laboratory results in which low-salinity injected water produced 5.8% OOIP incremental oil. These experimental results suggest that low-salinity injection may be an effective EOR technique for these reservoirs. Many Minnelusa reservoirs have been flooded for up to thirty years with low-salinity water providing numerous field cases. The preliminary evaluation used the source of injected water to provisionally assign fields into low salinity, mixed or saline classes. It appears that regardless of what groups of fields are considered there is no significant difference in recovery factors between fields with low salinity injection and those with saline brine (mixed+saline) injection.

Since some Minnelusa fields have fairly fresh formation water, further analysis quantified the degree of dilution using the salinity ration allowing comparison of recovery factors with degree of dilution. The experimental data to date show recovery can be increased with as little as 2.5-fold dilution and that increasing dilution increases incremental production (Alotaibi and Nasr-El-Din, 2010, Loahardjo et al. 2007). However, degree of dilution did not correlate with recovery.

Given the uncertainties associated with calculating recovery factors we also used normalized production at water breakthrough, a metric independent of recovery factor. The data show that there is no increase in timing of water breakthrough for fields with low-salinity injection compared to those with mixed or saline injection. Nor did we see the dual-step water breakthrough previously reported (Vledder et al. 2010).

Table 2. *Water breakthrough as a function of normalized cumulative production.*

Field	Inj. Water Type	Norm. Cum. at Breakthrough	Average
Hawk Point	1	0.44	
Candy Draw	1	0.25	
Simpson Ranch	1	0.25	
Spring Hole	1	0.25	
Moran	1	0.1	
Widge	1	0.2	
Timber Cr. N.	1	0.3	
Swartz Draw	1	0.1	**0.24**
Ash	2	0.5	
Indian Tree	2	0.25	
Deer Fly	2	0.05	
Big Mac	3	0.2	
Kiehl W	3	0.6	
Lily	3	0.18	
Lone Cedar	3	0.2	
Prairie Cr. S.	3	0.5	

Right A Way	3	0.1	
Glo N	3	0.6	
Victor	3	0.3	**0.32**

1 = low salinity, 2 = mixed, 3 = saline

5. CONCLUSIONS

There was no difference in performance as measured by recovery factor and water breakthrough for Minnelusa fields with low salinity injection compared to fields with saline water injection. The lack of apparent benefit from low-salinity injection may be due to a small benefit obscured by the large range of natural variability in recovery.

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