# Performance of Low Salinity Polymer Flood in Enhancing Heavy Oil Recovery on the Alaska North Slope

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# Performance of Low Salinity Polymer Flood in Enhancing Heavy Oil Recovery on the Alaska North Slope

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## Abstract

Combining low-salinity water (LSW) and polymer flooding was proposed to unlock the tremendous heavy oil resources (20-25 billion barrels) on the Alaska North Slope (ANS). The synergy effect of LSW and polymer flooding was demonstrated through coreflooding experiments carried out on representative rock and fluid systems. The results indicate that the high-salinity polymer solution (HSP, 2,300 ppm, salinity=27,500 ppm) requires nearly two thirds more polymer than the low-salinity polymer (LSP, 1,400 ppm, salinity=2,500 ppm) to achieve the same target viscosity of 45 cp measured from viscometer. Additional oil (5-9%) can be recovered from LSW flooding after extensive high-salinity water (HSW) flooding. LSW flooding performed in secondary mode can achieve higher recovery than in tertiary mode. Strikingly, LSP flooding can further improve the oil recovery by ~8% even after extensive HSP flooding with the same viscosity. LSP flooding performed directly after waterflooding can achieve ~10% more incremental oil recovery. The pH increase of the effluent during LSW/LSP flooding was significantly greater than that during HSW/HSP flooding, indicating the occurrence of ion exchange which might contribute to the improved oil recovery. Also, the water breakthrough was delayed in a low-salinity flood compared with a high-salinity flood. The idea of combining LSW and polymer flooding has been put into practice on a pattern-scale field pilot test in the target Milne Point field. Nearly two-year observation has shown impressive success: water cut reduction (70% to below 15%), increasing oil rate, and no polymer breakthrough so far. This work has demonstrated remarkable economical and technical benefits of combination of LSW and polymer flooding in enhancing heavy oil recovery.

## Introduction

Heavy oil resources are abundant and account for a large portion of the total oil reserves around the world. Thermal methods, like steam flooding, are effective techniques to develop the heavy oil resources. However, in some areas the thermal methods are not feasible. For example, the Milne Point heavy oil reservoir on the Alaska North Slope (ANS) is thin and covered with thick permafrost. Heat loss and environmental concerns make thermal recovery methods unacceptable. Waterflooding can maintain the production at the early stage, but it soon shows premature breakthrough and fast rise of water cut. Polymer flooding is believed an effective method to unlock the heavy oil resources in this area. Successful field applications of polymer flooding in heavy oil reservoirs have been reported around the world, like in Canada (e.g. Pelican Lake, Seal, Cactus Lake), China (e.g. Bohai Bay), Middle East, Suriname (e.g. Tambaredjo), and Trinidad and Tobago (Delamaide et al., 2014, 2018; Saboorian-Jooybari et al., 2016; Saleh et al., 2017; Zhang et al., 2016).

The first ever polymer flood pilot test on the ANS has been implemented since August 2018 (Dandekar et al., 2019; Dandekar et al., 2020; Ning et al., 2019; Wang et al., 2020). As a low-salinity water resource is readily available in the field and no additional facilities are required, it is possible to combine the advantages of low-salinity water and polymer flooding in a technically and economically attractive way at Milne Point. Despite the convenient implementation, however, it is challenging to fully understand the physics of the complex polymer/brine/oil/rock system. Systematic laboratory research work is required to verify their synergy, identify favorable conditions for implementation, and maximize the oil recovery performance.

Several researchers have discussed the technical and economic benefits of combining low-salinity water and polymer flooding. By using low-salinity water, one of the most direct benefits is significant reduction of the polymer consumption. For example, Vermolen et al. (2014) reported that the required polymer concentration could be reduced by 2-4 times using low-salinity water as make-up brine compared with high-salinity water. Shiran and Skauge (2013) reported 5% oil recovery increase during LSP flood in intermediate-wet cores after tertiary LSW flooding, and 12-17% oil recovery increase after secondary LSW flooding. Kozaki (2012) observed beneficial recovery from tertiary LSP flooding, both after insufficient HSW flooding and extensive HSW flooding. The research reported by ENI also demonstrated the EOR potential of LSP flooding over HSP flooding with aged reservoir sandstone cores (Moghadasi et al., 2019). Their experiments showed that the LSP flooding could achieve 8% additional oil after extensive HSP flooding with the same viscosity. Moreover, the LSP showed remarkable economic benefit, as much lower polymer concentration was used for LSP (300 ppm versus 1000 ppm). Almansour et al. (2017) performed six coreflooding experiments with Berea and Bentheimer sandstone cores. They reported that in intermediate-wet Berea cores, the tertiary LSP flooding significantly improved the oil recovery, and the improvement was greater after the HSW secondary flooding, 16.7% after the HSW flooding versus 11.6% after the LSW flooding. The beneficial effect of LSP flooding was also reported by a very recent study (Kakati et al., 2020).

In this study, the oil recovery performance of combination of LSW and polymer flooding is investigated under various conditions to improve heavy oil recovery at the Milne Point field. The performance of the two-year field pilot test performance is briefly discussed.

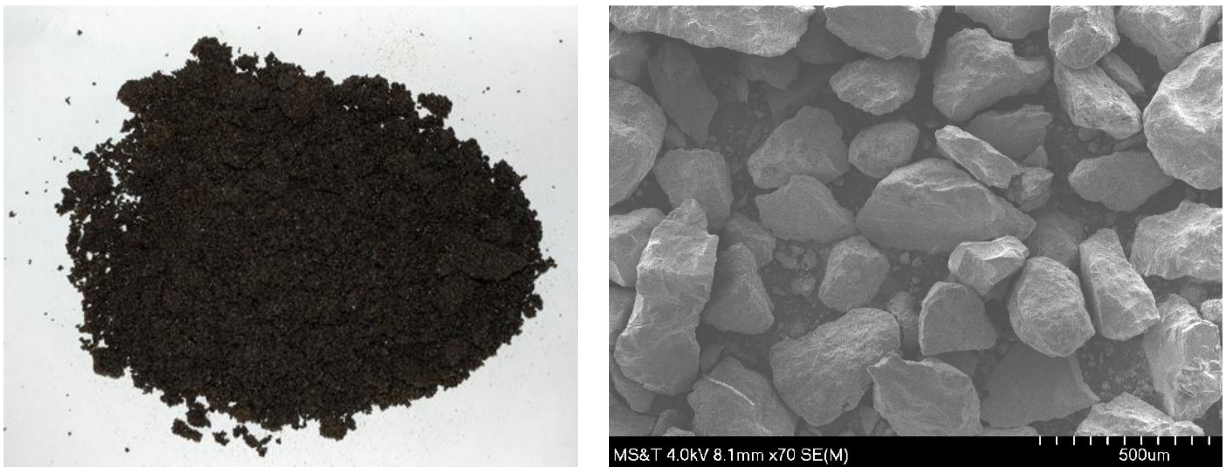
## Methods

**Brine**. Composition of formation brine and injection brine are shown in Table 1. The synthetic formation brine (SFB) and synthetic injection brine (SIB) were prepared in lab according to the respective brine compositions in the Milne Point field. The SFB (27500 ppm) and SIB (2498 ppm) are termed as HSW and LSW respectively in this paper.

**Polymer**. The polymer used is an acrylamide-acrylate copolymer, Flopaam 3630, provided by SNF Floerger. The hydrolysis degree is 25−30% with a molecular weight of 18-20 million Daltons. HSP and LSP were prepared with HSW and LSW, respectively. Prior to adding polymer powder, the brine was deoxygenated with argon. The desired amount of polymer was slowly added into the brine while being stirred with a magnetic bar at 300 rpm. The solution was stirred at room temperature for about 24 hours until all the polymer powders were well dissolved. The polymer solution was filtered through a 1.2-μm filter paper.

**Table 1 Composition of formation brine and injection brine**

| Name | Properties<br>(measured at 71 °F) | Composition<br>(ppm) |
|---|---|---|
| HSW<br>(SFB, synthetic formation brine) | pH=7.30<br>u=1.15 cp<br>TDS=27500 ppm<br>Ionic strength=0.492 | $Na^+$: 10086.0<br>$K^+$: 80.2<br>$Ca^{2+}$: 218.5<br>$Mg^{2+}$: 281.6<br>$Cl^-$: 16834.4 |
| LSW<br>(SIB, synthetic injection brine) | pH=7.50<br>u=1.07 cp<br>TDS=2498 ppm<br>Ionic strength=0.046 | $Na^+$: 859.5<br>$K^+$: 4.1<br>$Ca^{2+}$: 97.9<br>$Mg^{2+}$: 8.7<br>$Cl^-$: 1527.6 |




(a) Formation sand in native state (b) SEM image of the sand

**Figure 1 Formation sand**

**Crude Oil**. The crude oil was collected at a wellhead at Milne Point (Well #B-28). The oil sample was centrifuged to remove water and solids (if any), and filtered through a 0.5-μm filter paper. The viscosity of the oil was 202 cp at reservoir temperature (71 °F), and the API gravity was 19.0° (0.940 g/ml).

**Sandpacks**. The sand was from a crushed core sample from the target reservoir formation (Schrader Bluff NB sand) from Liviano-01A well at the Milne Point Unit. The formation was poorly consolidated and core samples were easily broken apart. The sand kept the native condition to some extent with crude oil attached on the sand surface, as shown in Figure 1(a). The sand was used as received to prepare the sandpacks. The sand contained 1.5% illite, 1.5% chlorite, 1% dolomite and ~10% albite and the remaining was quartz. The native-state sand and the SEM image are shown in Figure 1. The median size of the sand was about 170 μm. The sandpacks were prepared using a steel tube with an inner dimension of 2.54 cm × 20.4 cm. A piece of stainless steel screen was attached at the outlet end plug to prevent sand from being flushed out of the sandpack tube. A wet-packing method was adopted to prepare the sandpack. The sand was mixed with formation brine and set for about 24 hours to remove air bubbles attached on the sand. The sand was slowly added to the sandpack tube at multiple times. A hammer was used to knock the tube to make sure the sand was well packed. The pore volume and porosity were measured through tracer tests. After measuring the permeability with formation brine, crude oil was injected to establish the irreducible water saturation ($S_{wi}$).

**Viscosity Measurement**. The viscosity of injected and produced brine and polymer solutions was measured with a Brookfield viscometer at reservoir temperature (71 °F). The polymer showed power-law behavior. As the salinity was reduced, the required polymer concentration decreased to achieve the target viscosity (45 cp). The viscosities of HSP and LSP are shown in Figure 2. The viscosities of the two polymers were very close to each other. The concentrations of the two polymers were 2300 ppm and 1400 ppm, respectively. The HSP required 64% more polymer than the LSP to achieve the target viscosity.

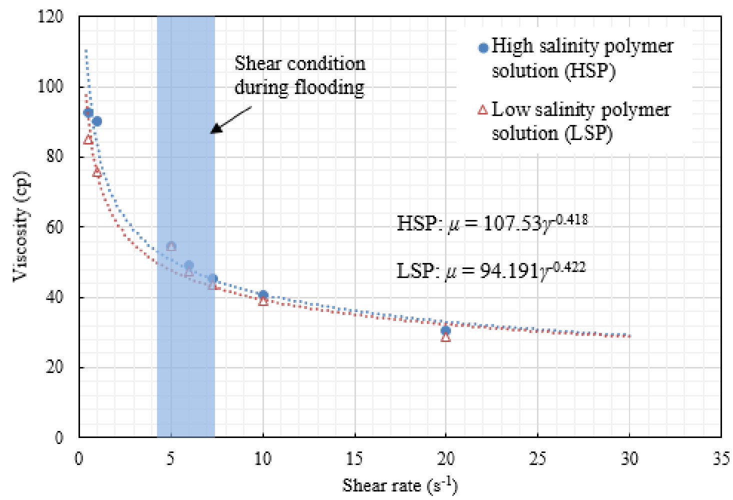



**Figure 2 Polymer viscosity (measured with Brookfield Viscometer at reservoir temperature, 71 °F)**

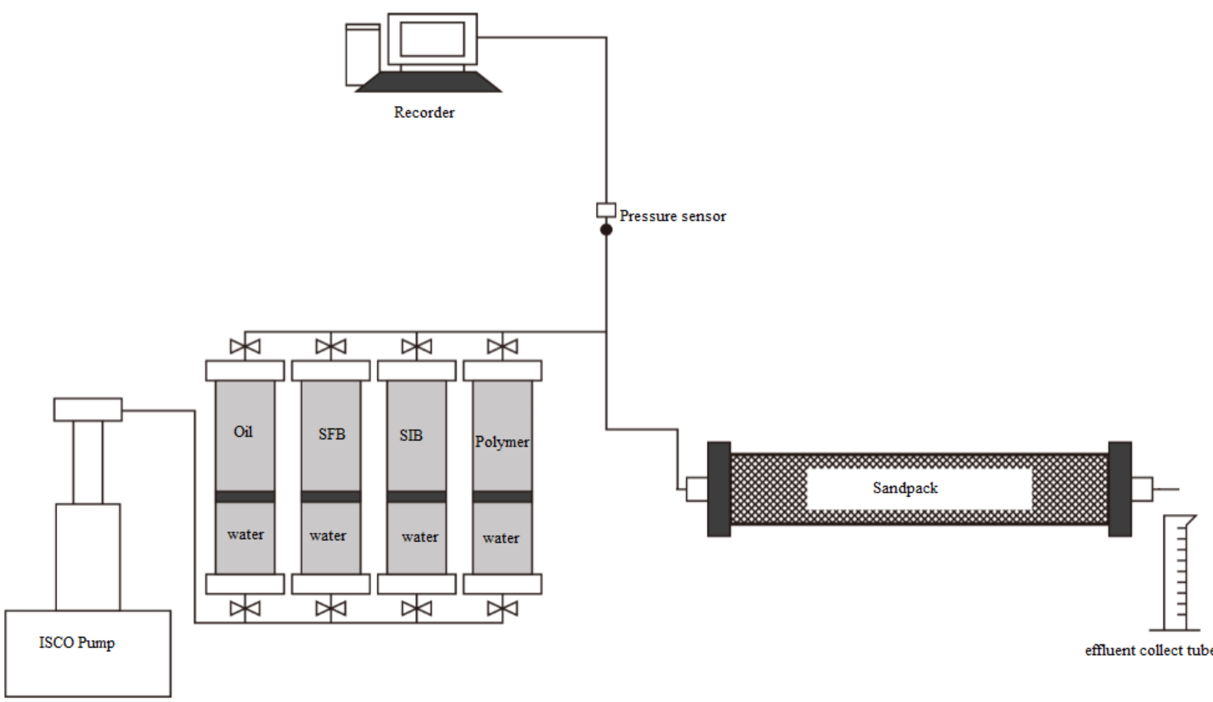



**Figure 3 Coreflooding experiment setup**

**pH Measurement**. The pH value of brine, polymer solutions, and aqueous phase of the effluent was measured with a pH meter with an accuracy of ±0.002 pH (Orion™ 2-Star Benchtop, Thermo Scientific). The pH values of the injected fresh HSW and LSW were 7.3 and 7.5 respectively. The pH values of the fresh HSP and LSP were 7.6 and 7.8 respectively.

**Coreflooding Experiments**. Figure 3 shows the coreflood setup. It consisted of a D-series ISCO syringe pump, accumulators, the sandpack assembly, pressure transducers and data acquisition system, effluent collection system, and tubing lines and valves. Five coreflooding experiments were carried out as shown in Table 2. The flow rate in the flooding process was set at 0.1 ml/min (equivalent to a Darcy velocity of ~1.2 ft/d). For each flood process, many pore volumes of displacing fluid were injected to drive the system to the residual oil saturation condition for that fluid. During the last several pore volumes (PVs) of injection in each flood process, no oil was produced. Increased flow rates were used at the end of a flooding process to check the capillary end effect.

**Table 2 Basic information of core flooding experiments**

| Exp # | Objective | d, cm | L, cm | porosity | K, md | $S_{wi}$ | Flooding process |
|---|---|---|---|---|---|---|---|
| CF1 | LSW in tertiary mode | 2.54 | 20.40 | 0.415 | 1770 | 0.160 | (1) HSW flooding to Sor<br>(2) LSW flooding to no oil production |
| CF2 | LSW in secondary mode | 2.54 | 20.40 | 0.453 | 16,205 | 0.112 | (1) LSW flooding to no oil production<br>(2) HSW flooding to no oil production |
| CF3 | LSP beyond HSP &waterflooding | 2.54 | 20.40 | 0.415 | 1770 | 0.160 | (1) HSP flooding performed after CF1 until no oil production<br>(2) LSP flooding to no oil production |
| CF4 | LSP beyond secondary HSP flooding | 2.54 | 20.40 | 0.236 | 248 | 0.261 | (1) HSP flooding to no oil production<br>(2) LSP flooding to no oil production |
| CF5 | LSP right after waterflooding | 2.54 | 20.40 | 0.316 | 478 | 0.109 | (1) HSW flooding to Sor<br>(2) LSW flooding to no oil production<br>(3) LSP flooding to no oil production<br>(4) HSP flooding to no oil production |

## Results and Discussion

The oil recovery results are summarized in the Table 3. The results are discussed in the following subsections.

**Table 3 Summary of coreflooding results**

| Exp # | Secondary flood | Secondary oil recovery, % | Sor after Secondary flood | Incremental oil recovery, % | | | | Final Sor | Final recovery, % |
|---|---|---|---|---|---|---|---|---|---|
| | | | | HSW | LSW | HSP | LSP | | |
| CF1 | HSW | 37.9 | 0.522 | / | 8.7 | / | / | 0.449 | 46.6 |
| CF2 | LSW | 49.4 | 0.482 | 0.4 | / | / | / | 0.479 | 49.9 |
| CF3 | HSW | 37.9 | 0.522 | / | 8.7 | 7.4 | 8.0 | 0.320 | 61.9 |
| CF4 | HSP | 71.2 | 0.213 | / | / | / | 5.7 | 0.171 | 76.9 |
| CF5 | HSW | 43.9 | 0.500 | / | 5.6 | 0.4 | 10.6 | 0.351 | 60.6 |

### LSW Flooding: Tertiary versus Secondary

CF1 and CF2 were conducted to investigate the performance of LSW flooding performed in tertiary mode and secondary mode, respectively. The tertiary LSW flooding was performed at residual oil saturation ($S_{or}$) condition established after extensive HSW waterflooding. The results are shown in Figures 4-6.

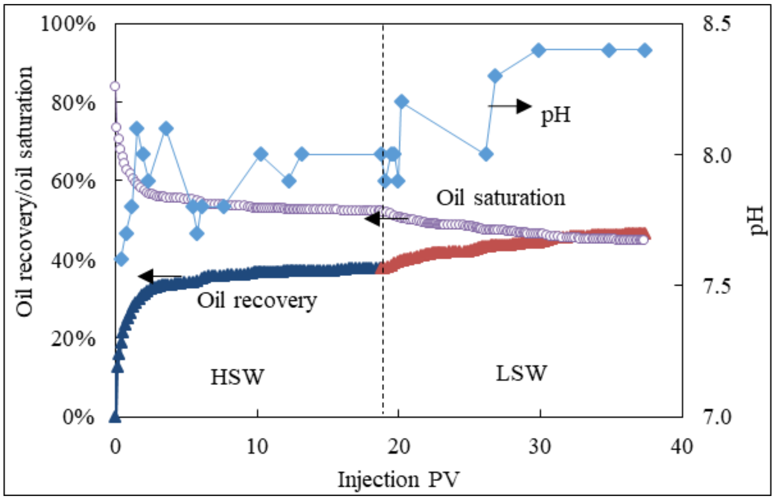



**Figure 4 Tertiary LSW flooding (CF1)**

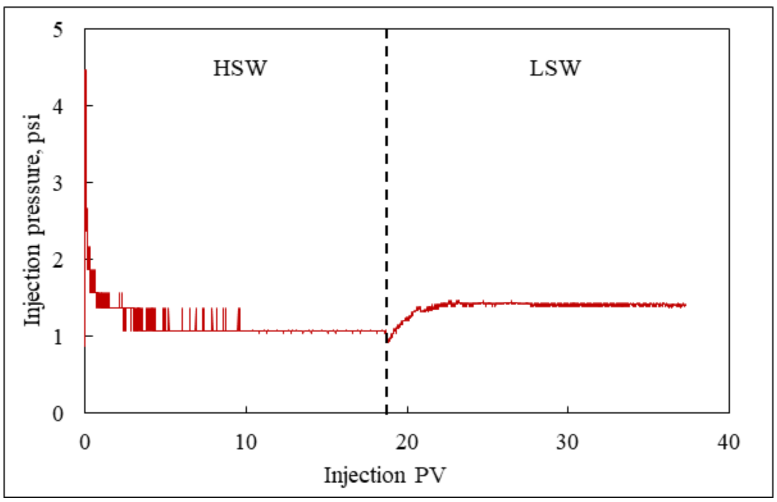



**Figure 5 Injection pressure in CF1**

**Tertiary LSW Flooding**. HSW flooding was first conducted in CF1 as a secondary recovery method. The water breakthrough occurred at 0.13 PV of injection and 15.2% of the oil originally in place (OOIP) was recovered. After breakthrough, the water cut quickly increased up to 90% after 0.76 PV of injection, and further climbed to 99% after 2.9 PV. However, it took a long time (>15 PV) to visually reach the no-oil-production condition (water cut=100%). Then several additional PVs of water were injected to confirm no more oil could be produced. The long tail indicated the displacement was significantly distorted from a piston-like fashion. It resulted from the adverse mobility ratio between the injected brine and the viscous oil, which can be theoretically supported by the Buckley-Leverett theory (Buckley & Leverett, 1942; Pope, 1980; Maini, 1998). For heavy oil, the displacement process is highly unstable and the water tends to finger into the oil and further develop into channels preferential to water flow between the injectors and producers. A total of 18.7 PV of HSW was injected. The endpoint oil saturation after such extensive flooding (> 10 PV) was regarded as the residual oil saturation in this work. It may be still not the exactly true residual oil saturation due to the high viscosity of the oil (Wassmuth et al., 2007). The oil recovery reached 37.9% and the Sor was 0.522. About two thirds of the recovered oil was obtained after water breakthrough.

After the secondary HSW flooding, extensive PVs of LSW were injected into the core to test whether lowering the salinity could effectively recover more oil beyond the HSW flooding. The water cut was obviously reduced and 8.7% additional oil was recovered. The oil recovery factor was increased to 46.6%. The results demonstrate the positive effect of low salinity in enhancing the heavy oil recovery efficiency. The results are consistent with the recent experimental work which showed improved oil recovery performance (6.3% OOIP) of LSW flooding (TDS=3,000 ppm) over HSW flooding (TDS=28,000 ppm) for the target Milne Point heavy oil (Cheng et al., 2018).

The capillary end effect was checked according to the Rapport-Leas scaling parameter, $Lv\mu$, which should be higher than 3.5 $cm^2min^{-1}cp$ ( Rapoport & Leas, 1953; Qi, 2018), where L is the length of the core, cm; μ is the viscosity of the displacing fluid, cp; and v is the Darcy velocity, cm/min. The scaling parameter during water flooding was 0.43, thus a capillary end effect was likely. At the end of HSW flooding and LSW flooding, the flow rate was increased to 0.2, 0.5, 1.0 and 2.0 ml/min. No additional oil was produced at the increased flow rates. Note that the scaling parameter at 2.0 ml/min was 20 times higher and well above the critical value. The results indicated the end effect was negligible.

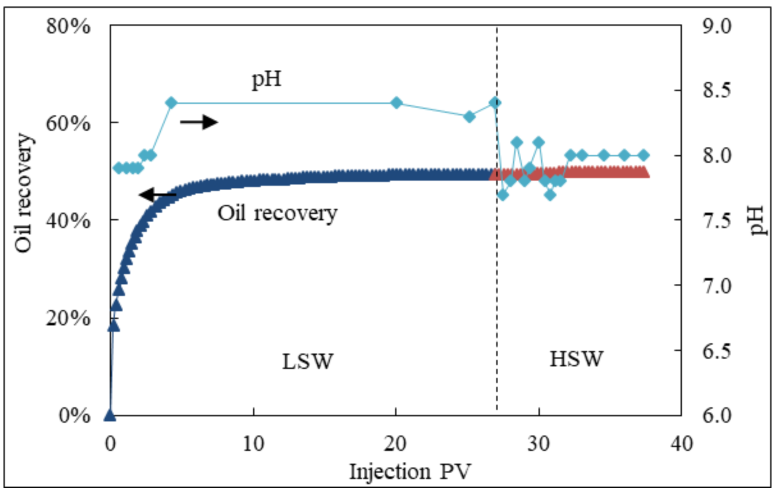



**Figure 6 Secondary LSW flooding (CF2)**

**Secondary LSW Flooding**. CF2 was directly flooded using LSW as the secondary recovery method. The water breakthrough occurred at 0.18 PV and 20.0 % of the oil originally in place (OOIP) was recovered. The breakthrough occurred later and more oil could be recovered compared to the HSW flooding in CF1. The water cut increased up to 90% after 0.96 PV of injection, and further rose up to 99% after 4.9 PV. The production duration at relatively-lower-water-cut level lasted remarkably longer than the secondary HSW flooding. The behavior indicated the displacement was more stable during the LSW flooding. A total of 27 PV of LSW was injected. Compared with the secondary HSW flooding, the secondary LSW flooding achieved a higher recovery efficiency (49.4% vs. 37.9%) and drove the core to a lower Sor (0.482 vs. 0.522). Tertiary HSW flooding after the LSW flooding was attempted, but no appreciable incremental oil recovery was observed, as shown in Figure 6. The overall oil recovery after the tertiary flooding was 49.9%, which was higher than that in CF1 (46.6%). Considering the breakthrough behavior and oil recovery efficiency, the results suggest that the LSW flooding can achieve a better performance than the HSW flooding, and the secondary LSW flooding is better than that performed in the tertiary stage. The results are qualitatively consistent with the observations reported by Shiran & Skauge (2013). They suggested that a secondary LSW was better than a tertiary one because during the secondary HSW flooding, the residual oil was trapped in the pore throat structures in the swept area. The tertiary LSW tended to follow the water pathways. The low salinity water could not remobilize the trapped oil in the pathways. Only imbibition could occur so that the LSW was imbibed into secondary pores away from the main flow. The imbibition was a relatively slow process and the low salinity benefit was well delayed as observed. Also, the snap-off events were weakened during the secondary LSW flooding. For heavy oil, due to the unfavorable mobility ratio, the less-swept and unswept regions are expected to be significant after waterflooding. Therefore, the tertiary LSW still has a better chance to recover additional oil compared with the cases with less viscous oil as Shiran & Skauge (2013).

As shown in Figure 5, the injection pressure during LSW flooding was higher than that during HSW flooding, and no fines production was observed during the entire flooding process. The increased injection pressure may be due to the wettability alteration induced by the ion exchange and the release of polar components from the pore surfaces. The relative permeability was reduced and the water relative permeability decreased.

The pH change of the produced aqueous phase in CF1 and CF2 was plotted in Figures 4 and 6. As shown in Figure 4, the pH was stabilized at 8.0 during HSW flooding, while during the tertiary LSW flooding, the pH quickly increased from 7.9 to above 8.2 and gradually stabilized at 8.4, which was almost 1.0 pH unit higher than the injected value. The major pH increase coincided well with the incremental oil recovery process. A similar trend was observed in CF2, as shown in Figure 6. The pH increase indicated the presence of a low-salinity effect (LSE) (Rezaeidoust et al., 2011; Shiran & Skauge, 2013). At the initial stage, polar components could be adsorbed onto the pore surface either directly or through divalent cations. The cations acted as a bridge to attach the polar components onto the pore surface (mainly the clay surfaces). The invasion of LSW disturbs the adsorption equilibrium status. Ion exchange occurs as a result of the ion concentration gradient between the invading LSW and the in-situ brine, especially at the pore surface. The hydrogen ions were adsorbed onto the surface and the divalent cations were released. Also, the hydroxide ions could react with the acidic and basic components through acid-base reaction, thus the polar components attached to the pore surface were released. As the polar components were detached from the clay surfaces, the surfaces become more water-wet.

**LSP Flooding beyond Waterflooding and HSP Flooding**

In CF3, the performance of LSP flooding was investigated after extensive waterflooding and HSP flooding, as shown in Figure 7. Strikingly, even after extensive flooding with HSP, significant incremental oil was achieved when injecting low-salinity polymer. Though the viscosity was almost the same with the normal salinity polymer and the concentration was significantly lower, the oil recovery incremental was remarkable, 8.0% OOIP, and the overall oil recovery factor reached 61.9%. The pH was increased during the LSP flooding especially at the early stage, which coincided well with the incremental oil recovery. The pH increase indicated ion exchange took place during the flooding process (Rezaeidoust et al., 2011). Note that the core had already been exposed to low-salinity invasion fluid during the LSW flooding process, as shown in Figure 7. The low-salinity effect (e.g. ion exchange, polar component desorption and wettability alteration) had already taken effect in the pores swept by the LSW (the well swept region. However, there was still an appreciable portion of oil left in the less-swept region and unswept region after the LSW flooding. Though additional oil could be displaced out during the HSP flooding (7.4% OOIP), still the low salinity water had a chance to recover more oil beyond the HSP. The mechanisms responsible for the incremental oil recovery should be similar with the case of LSW flooding. The results demonstrate the synergy effect of LSW and polymer flooding in enhancing the heavy oil recovery.

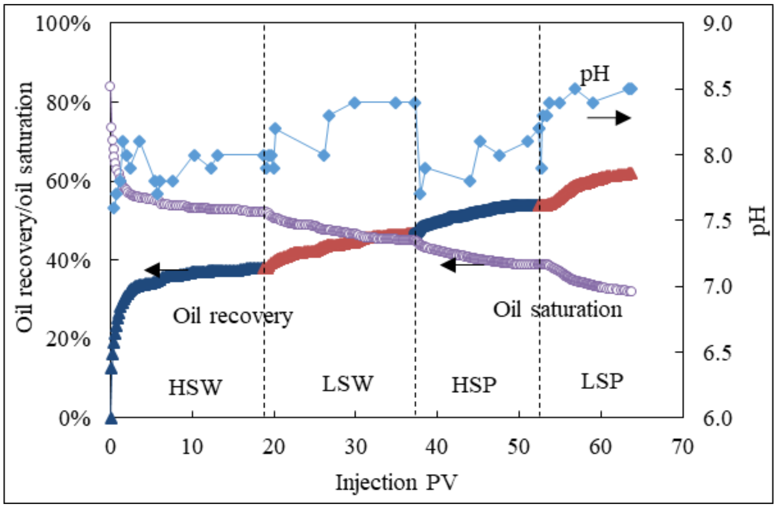



**Figure 7 LSP flooding beyond waterflooding and HSP flooding (CF3)**

### LSP Flooding after Secondary HSP Flooding

In CF4, the LSP flooding was performed after the extensive secondary HSP flooding. The results are shown in Figure 8. The incremental oil recovery was 5.7% OOIP. The overall oil recovery was increased to 76.9% after the LSP flooding. The residual oil saturation was reduced from 0.21 to 0.17. The pH of the effluent was increased during the LSP flooding, which indicated the presence of the low salinity effect. The improved oil recovery was mainly ascribed to the low salinity effect. Further discussion of the results are presented in the following subsection.

### LSP Flooding Directly after Waterflooding

In CF5, the LSP flooding was performed after extensive waterflooding (including HSW flooding and LSW flooding). The results are shown in Figure 9. The oil recovery factor reached 60.1% after the LSP flooding, and 10.6% additional oil was recovered in this process. The incremental recovery was higher than the LSP flooding after extensive waterflooding and HSP flooding (CF3), and was almost double that after secondary HSP flooding (CF4). The LSP flooding performed in this scheme was also better than the HSP flooding, as observed in CF3, in which the incremental recovery of HSP flooding after extensive waterflooding was 7.4% OOIP. Some researchers reported considerable incremental oil recovery and Sor reduction in a high-salinity polymer flood after a low-salinity polymer flood (Erincik et al., 2018; Qi et al., 2017). Their impressive observations may be related to the viscoelasticity effect of the polymer solution present at high shear rate condition. It may also be due to other specialized conditions associated with their experiments (e.g., core conditioning). In our experiments performed at normal flow velocity as in the reservoir, ~1.2 ft/d; however, no appreciable incremental recovery was observed in the HSP flooding following the LSP flooding, indicating the injection scheme has an important impact on the oil recovery performance.

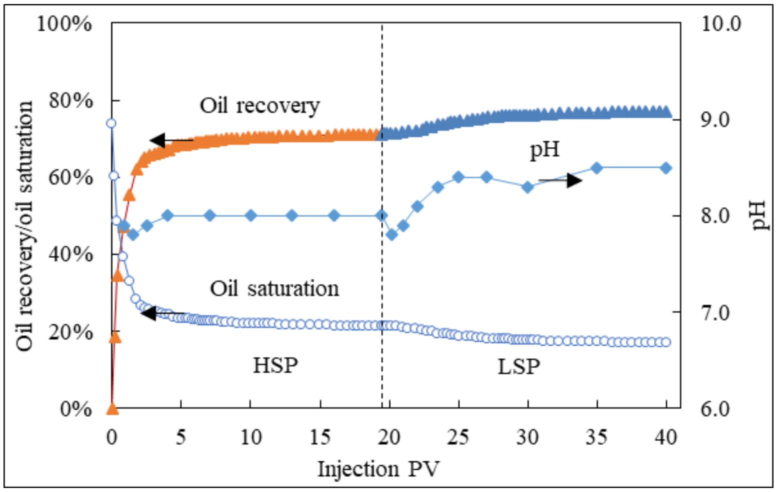



**Figure 8 LSP flooding after a secondary HSP flooding (CF4)**

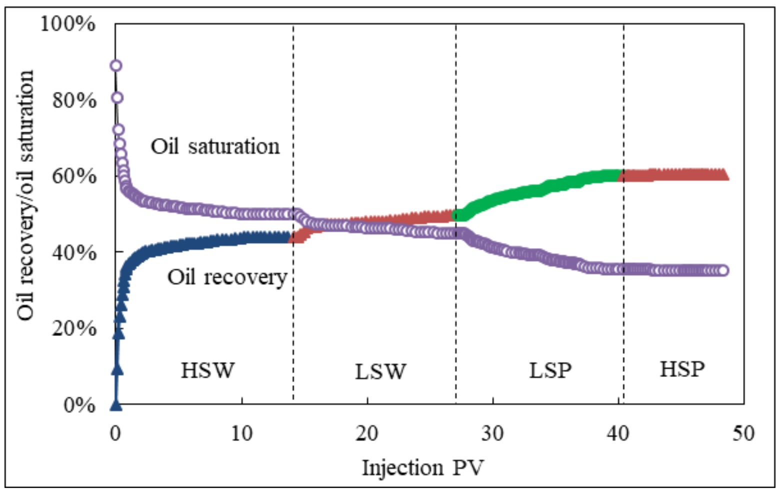



**Figure 9 LSP flooding directly after waterflooding (CF5)**

The LSP flooding after a secondary HSP flooding (CF4) can improve the oil recovery efficiency mainly due to the LSE. The sweep efficiency in the secondary HSP flooding was higher than that in the HSW flooding and LSW flooding in CF5. Thus, most of the pore space in the core was well swept. Further improvement in sweep is expected to be minimum in the following LSP flooding due to the similar viscosity of the two polymer solutions. The incremental recovery was not as significant as the case of LSP flooding after waterflooding (CF5). In the latter case, the less-swept region and unswept region were still significant after waterflooding. The LSP had a better chance to achieve additional oil recovery through both sweep improvement and a low salinity effect. In the less-swept region and the unswept region, LSP flooding could achieve a better sweep efficiency and establish a lower Sor through the LSE. Also, the oil thread/column stabilization effect was favorable for the polymer to establish a lower residual oil saturation, as the oil saturation in the less swept and unswept regions was higher than the Sor after extensive waterflooding. The mechanism was similar to a secondary polymer flood (Huh & Pope, 2008).

Some researchers attribute the residual oil saturation reduction to the viscoelasticity of the polymer solution ( Wang et al., 2000; Xia et al., 2004; Yin et al., 2006; Erincik et al., 2018; Koh et al., 2018; Qi, 2018; Azad & Trivedi, 2019a, 2019b, 2020; Jouenne & Heurteux, 2020). But viscoelasticity is only significant at high shear-rate condition, as indicated by the shear thickening effect at high flux (Seright, et al., 2011; Seright, 2011). More work is required to clarify the role of the viscoelasticity property in the improved oil recovery and reduced residual oil saturation during the LSP flooding performed at relatively low velocity conditions.

Nevertheless, the results clearly demonstrate that combination of LSW and polymer flooding can significantly improve the oil recovery performance. The residual resistance factor (the ratio of water injection pressure before and after the polymer flooding) of both LSP and HSP were below 1.5, indicating injectivity loss and formation damage were not a concern during the polymer flooding.

**Field Application Evaluation**

The idea of combining LSW and polymer flooding has been put into practice on a pattern scale pilot test in the Milne Point field on the North Slope of Alaska. The flood pattern consists of two horizontal injection wells and two horizontal producers. Detailed field practice can be found in recent papers and publications to come (Dandekar et al., 2019, 2020; Ning et al., 2019). The pilot test has been going on for nearly two years and the field performance up to now (May 2020) has preliminarily demonstrated the game-changing potential of low-salinity polymer flood in unlocking the enormous heavy oil resources on the Alaska North Slope. The pilot test has shown impressive successful responses (Figures 10-11): the injectivity is sufficient to replace the production voidage; the water cut reduced from 70% at the start of LSP flooding to less than 15%; and no polymer breakthrough so far. Figures 10 and 11 also show that the oil rate has reversed the decline trend (as would be expected during waterflood) and started to increase due to improved sweep by the injected polymer. Detailed field performance and benefit analysis will be presented in future publications.

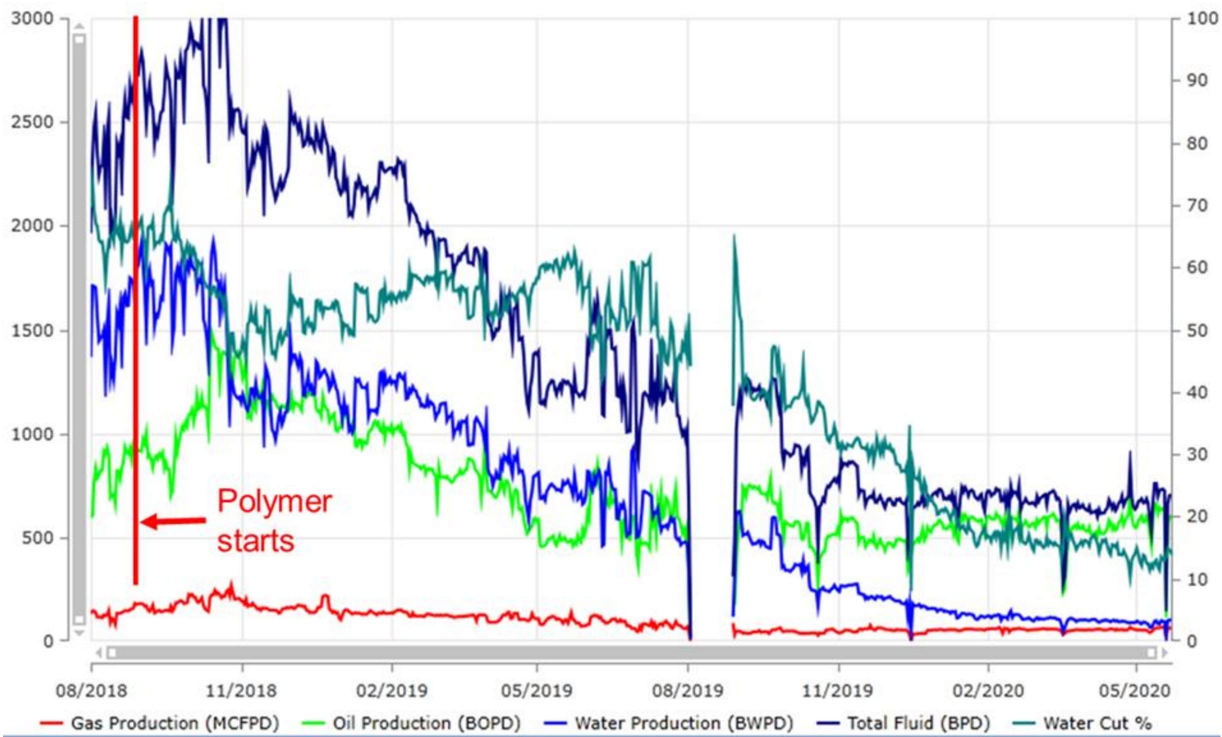



**Figure 10 J-27 production performance**

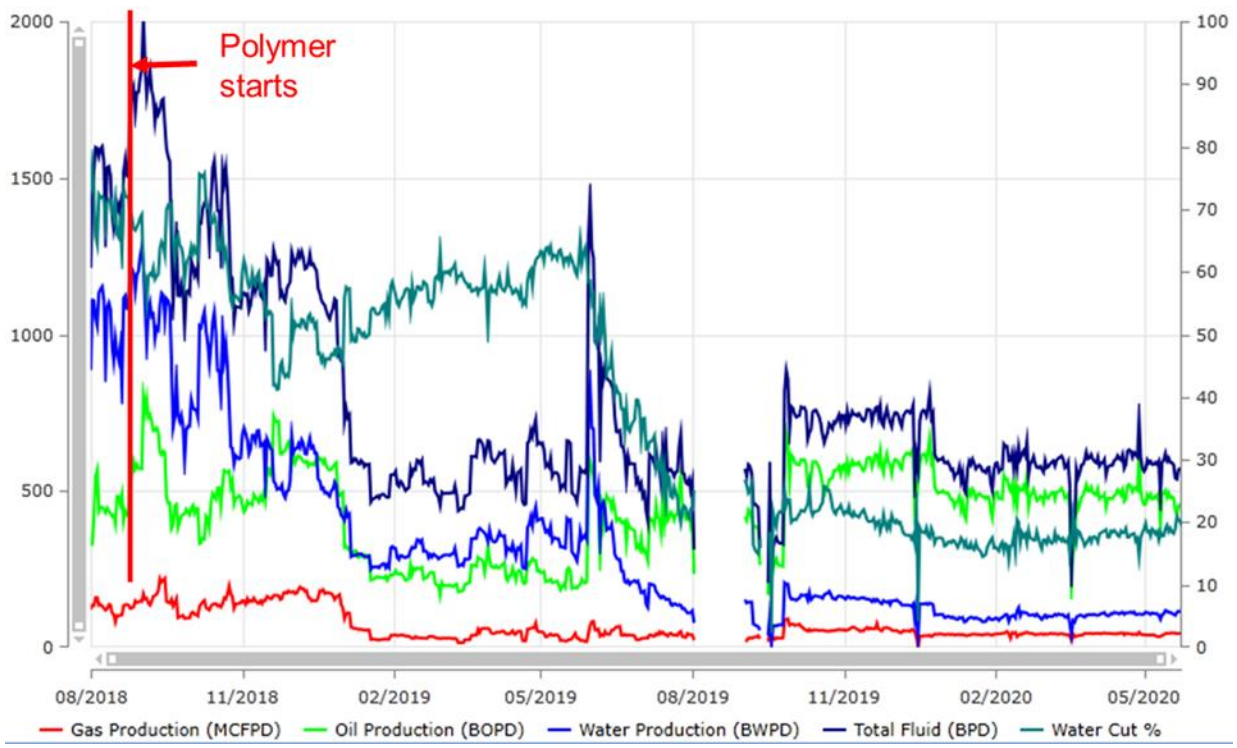



**Figure 11 J-28 production performance**

## Conclusions

(1) The HSP requires nearly two thirds more polymer than the LSP to achieve the same target viscosity.

(2) LSW flooding performed in secondary mode is better than in tertiary mode, and the water breakthrough occurs later than the secondary HSW flooding. LSP flooding can further improve the oil recovery, by ~8%, after extensive HSP flooding with the same viscosity. Ion exchange may occur as indicated by the increased pH during LSW flooding and LSP flooding.

(3) Three regions could exist after waterflooding: the well-swept region, less-swept region, and unswept region. LSP flooding performed directly after waterflooding can achieve ~10% more incremental oil recovery, which is ascribed to improved sweep efficiency and LSE in the less-swept region and unswept region.

(4) Field application practice has demonstrated remarkable success regarding water cut reduction, oil production improvement, and delayed breakthrough behavior.

(5) The synergy of combining low-salinity water and polymer flooding has been demonstrated under various conditions in this study. Future work is required to further investigate the rheology behavior under reservoir conditions, polymer retention, in-situ emulsification, and the impact of wettability at varying salinity conditions.

## Nomenclature

ANS = Alaska North Slope
EOR = Enhanced oil recovery
FW = Formation water, salinity=27500 ppm

HSP = High-salinity polymer, salinity=FW
HSW = High-salinity water, salinity=FW
LSP = Low-salinity polymer, salinity=injection source brine in the Milne Point field
LSW = Low-salinity water, salinity=injection source brine in the Milne Point field
OOIP = Oil originally in place
$S_{or}$ = Residual oil saturation
$S_{wi}$ = Irreducible water saturation

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