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First Ever Polymer Flood Field Pilot to Enhance the Recovery of Heavy Oils on Alaska's North Slope – Polymer Injection Performance

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Abstract

Alaska North Slope (ANS) holds an estimated 20-30+ billion barrel heavy oil resources, yet the development pace has been very slow due to high development costs and low oil recovery using conventional waterflood and EOR methods. The objective of this pilot is to perform a field experiment to validate the use of an advanced polymer flooding technology to unlock the vast heavy oil resources on ANS.

The advanced polymer flooding technology combines polymer flooding, low salinity water flooding, horizontal wells, and if necessary, injection conformance control treatments into one integrated process to significantly improve oil recovery from heavy oil reservoirs. Two pairs of horizontal injection and production wells have been deployed in an isolated fault block of the Schrader Bluff heavy oil reservoir at the Milne Point Field to conduct a polymer flood pilot. The pilot will acquire scientific knowledge and field performance data to optimize polymer flood design in the Schrader Bluff heavy oil reservoirs on ANS.

Polymer injection started on August 28, 2018 using a custom made polymer blending and pumping unit. This paper focuses on the facility setup and polymer injection performance into the horizontal injectors drilled and completed in the Schrader Bluff heavy oil reservoir. Partially hydrolyzed polyacrylamide (HPAM) polymer was selected and the initial target viscosity was set at 45 centipoise. Polymer injection rate was set at 2200 bbl/day for one injector (J-23A) and 1200 bbl/day for the other (J-24A) based on production voidage. Injection pressure was controlled at below fracture pressure to prevent fracturing the reservoir and causing fast breakthroughs. Step rate and pressure falloff tests indicate that short term polymer injectivity is similar to water injectivity, which means that injectivity is mostly controlled by fluid mobility deep in the reservoir rather than that in the vicinity of the injection wellbore. Long term injection data indicate that polymer injectivity has been decreasing in both injectors as the reservoir is filled by polymer. No polymer has been observed in the production stream 7 months after the start of polymer injection compared with a 3-month breakthrough time with waterflood. This indicates that polymer significantly delays breakthrough time which will lead to increased sweep efficiency.

Introduction

Numerous papers have been published on the vast heavy/viscous oil resources on the Alaska North Slope (ANS), which ranges from 20 to 30+ billion barrels (Paskvan et. al. 2016, Young et. al. 2010). Figure 1 depicts the areal extent of this underdeveloped unconventional oil resource covering the Kuparuk River Unit (KRU), Nikaitchuq Unit, Milne Point Unit (MPU), and part of the Prudhoe Bay Unit (PBU) on ANS. In this particular figure, “viscous oil (VO)” refers to the oil deposits in the Schrader Bluff formation (also called West Sak on the Western North Slope) at vertical depths from 2,000 to 5,000 feet with oil viscosities ranging from 5 cP to 10,000 cP, while “heavy oil (HO)” refers to oil deposits in the shallower Ugnu formation with oil viscosities ranging from 1,000 cP to 1,000,000+ cP. However, in the rest of this paper we will refer to both as “heavy oil” which is a more commonly used terminology in the industry. The developed areas are shown in dark blue and the light blue areas are undeveloped Schrader Bluff – west Sak resources. The red outline delineates the heavy oil deposits in the Ugnu formation which do not currently have any commercial production.

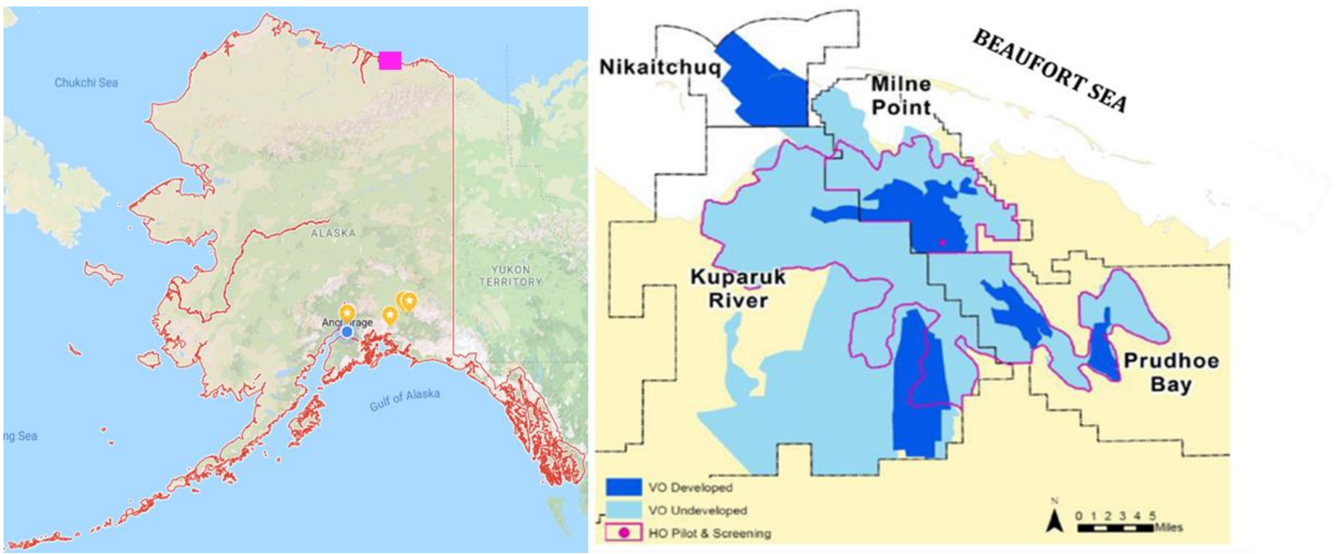

Figure 1. Alaska’s viscous oil and heavy oil reserves (Modified from Paskvan et. al. 2016)

Even after three decades of development efforts by multiple operators, total heavy oil production rate from all ANS fields just reached 57,287 BPD by February 2019 (Monthly Production Reports, Alaska Oil and Gas Conservation Commission) and cumulative oil recovery to date is 255 million barrels which is less than 1% of the total heavy oil in place. Even in the developed areas, the expected oil recovery factor from waterflood is generally less than 20% of Original Oil in Place (OOIP) due to the high (unfavorable) mobility ratio (>20) resulting in poor sweep efficiency. Miscible flooding processes have not been adopted because the miscibility pressure between the heavy oil and solvent (hydrocarbon based or CO_2) would be much higher than the reservoir pressure. Although there is limited application of immiscible enriched gas injection in the Schrader Bluff heavy oil reservoirs via the viscosity reduction water-alternating-gas (VRWAG) process (McGuire et. al. 2005), the expected incremental oil recovery is relatively small compared with the miscible process. Thermal recovery methods such as steam injection are impractical on ANS because of the high cost and concerns of thawing the permafrost, which could cause unpredictable environmental impacts. Therefore, polymer flooding is becoming an attractive EOR technique in such reservoirs, especially with the extensive application of horizontal wells and advancement of polymer flooding technology.

The US Department of Energy and Hilcorp Alaska, LLC are jointly cosponsoring a 4-year field pilot project entitled “First Ever Field Pilot on Alaska’s North Slope to Validate the Use of Polymer Floods for

Heavy Oil Enhanced Oil Recovery (EOR)" which is also known as "Alaska North Slope Field Laboratory (ANSFL)." The overall goals of the project are: (1) Systematically evaluate an advanced polymer technology that will integrate polymer flooding, low salinity water flooding, horizontal wells, and injection conformance control treatments into one process to significantly enhance oil recovery for heavy oil reservoirs; (2) Gain field polymer flood performance data to optimize polymer flood design in the Schrader Bluff heavy oil reservoir on Alaska's North Slope; (3) Minimize disruption to current/existing field operations, and minimize risk of lost production or damage to the wells, reservoir, facilities and the environment, and; (4) Resolve important outstanding technical issues regarding polymer flooding of heavy oils – including the desired polymer viscosity/concentration, salinity, retention, early polymer breakthrough, and treatment of produced fluids that contain polymer.

The overall scope of the aforementioned project has been described by Dandekar *et al* (Dandekar *et al* 2019) in a previous paper presented earlier this year. The focus of this paper is on the facility setup and the polymer injection performance of the two horizontal injectors as well as production responses to date.

The pilot area is at J-pad of the Milne Point field (Figure 2) which is located approximately 30 miles northwest of Prudhoe Bay Field and 15 miles Northeast of Kuparuk field on the North Slope of Alaska. Milne Point field was discovered in 1969 and production began in November 1985. Operated and owned by Conoco, production from the field was suspended between January 1987 and April 1989 due to low oil prices. The average production rate from April 1989 through December 1993 was 18.2 MBD (thousand barrels per day). In January 1994, BP acquired 91.2% interest and became field operator and then acquired the remaining interest in 2000. As a result of additional drilling and facilities construction, production peaked at 59.1 MBD in July 1998. In November 2014, Hilcorp acquired 50% interest in Milne Point field and assumed operatorship. Oil production rate ranged 18 to 22 MBD from 2014 to 2018 and is expected to increase to over 30 MBD by end of 2019 due to new developments using extended horizontal wells (up to 12,000 ft) in the Schrader Bluff heavy oil reservoir at the new Moose Pad as well as other existing drilling pads in the field.

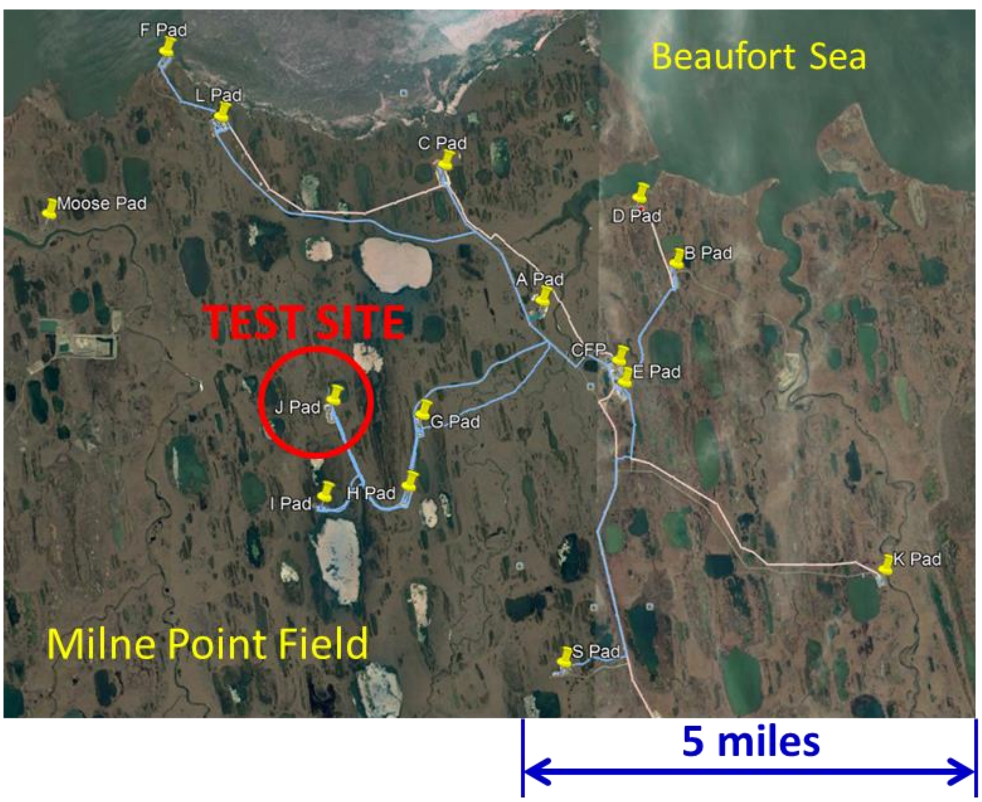

Figure 2. Location of the pilot area at Milne Point J-pad

The Milne Point field consists of four separate oil-bearing formations, listed from shallowest to deepest: Ugnu, Schrader Bluff, Kuparuk, and Sag River. The Ugnu formation is a shallow and unconsolidated sandstone reservoir containing heavy oil which is yet to be developed. The sandstones of the Kuparuk formation contain light oil and have historically been the main producing reservoir at Milne Point. The Sag River is the deepest hydrocarbon-productive formation in Milne Point with very light oil.

The Schrader Bluff formation was deposited in the Late Cretaceous period and was composed of several marine shore face and shelf deposits (McGuire et. al 2005). Figure 3 is a typical log of the Schrader Bluff formation at Milne Point field which is divided into the O-sands (OA and OB) and the N-sands (NA through NF). The project wells are completed in the NB sand which is a thin and unconsolidated shallow marine sandstone with a thickness of 10-18 feet in the J-Pad area of Milne Point. Porosity is approximately 32% and permeability ranges from 500 md to 5000 md. Oil gravity is about 15 degrees API in the project area with a viscosity of ~300 cP at the reservoir conditions.

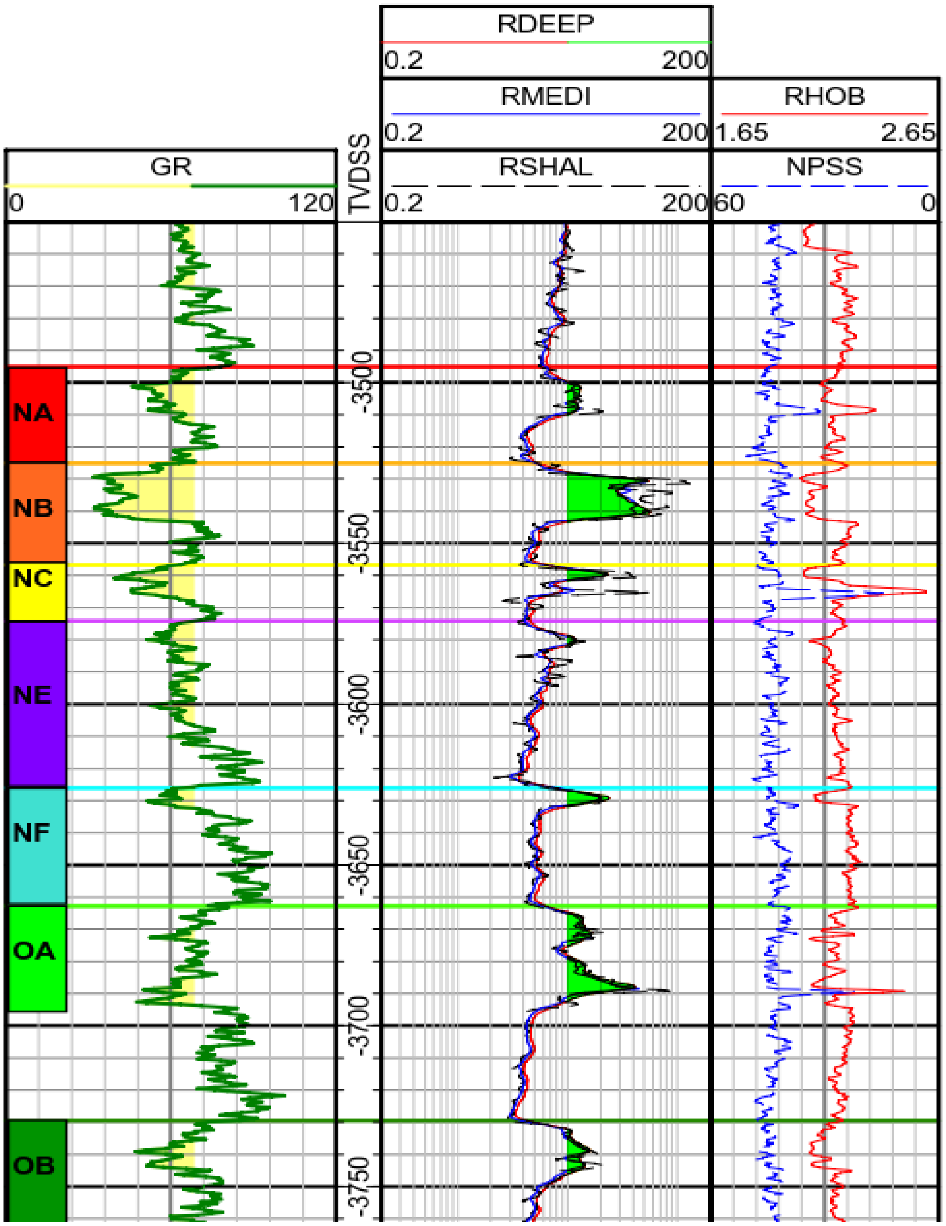

Figure 3. Type log of the Schrader Bluff NB and OA sands.

Figure 4 is a subsurface map showing the horizontal well patterns involved in the project which consists of two injectors (J-23A and J-24A) and two producers (J-27 and J-28) drilled into the Schrader Bluff NB-sand. The lengths of the horizontal wellbores are from 4200 to 5500 feet and the inter-well distance is approximately 1100 feet.

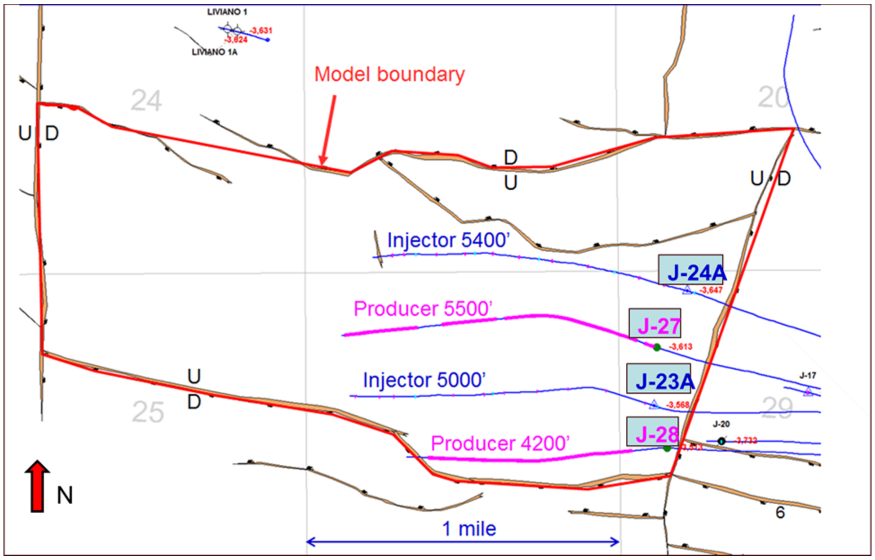

Figure 4. Project well patterns

Figure 5 is a wellbore diagram for injector J-24A which is similar to that of J-23A. The injectors are completed with 4-½" liners equipped with injection control devices (ICD) and swell packers to divide the wellbores into segments. There are 10 ICD's installed in J-24A, each contains ten ⅛" nozzles which are used to regulate water flow along the wellbore. In case there is a thief zone that creates fast connection between the injector and producers, the ICD's in that section of the wellbore will act like chokes to limit water flow into the thief zone.

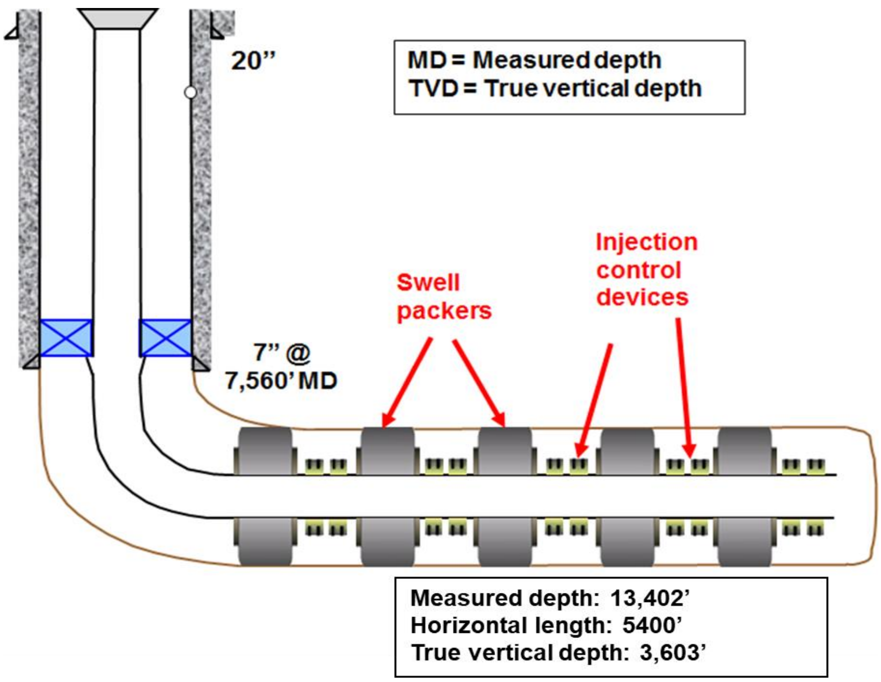

Figure 5. J-24A wellbore diagram.

Methods

Water injection started in June 2016 at J-23A and February 2017 at J-24A, while polymer injection started on August 28, 2018 at both injectors via a polymer slicing unit (PSU). The polymer mixing and pumping skids were custom designed and manufactured for this project. As shown in Figure 6, the PSU consists of 5 modules: the pressure letdown module, the injection pump module, the polymer make-down module, the hopper and the utility module. Polymer powder is transported and stored in super sacs, each containing 750 kg (~1650 lb) of polymer. The super sacs are loaded onto the hopper with a forklift and the polymer is fed into the polymer make-down unit below where it is mixed with water to make a mother solution. After 100 minutes hydration time in the tank, the mother solution is slipstreamed into the main water supply that feeds into 3 triplex positive displacement injection pumps in the pumping unit, one for each injector plus a spare.

Figure 6. Polymer slicing unit (source: SNF)

The PSU was installed at the project site in the summer of 2018 and started with water injection for a few days before ramping up polymer injection. Polymer injection started on August 28, 2018 at 600 ppm ramping up to1800 ppm in about 10 days to achieve a target polymer viscosity of 45 cP which might be adjusted during the project based on predicted benefit optimization and field performance. A commercially available HPAM polymer is currently being pumped at approximately 1800 ppm as shown in Figure 7. Lesson learned here was that operator involvement earlier in design or improved vendor understanding of end user capabilities/needs would likely have resulted in a shorter tie-in window and lower costs.

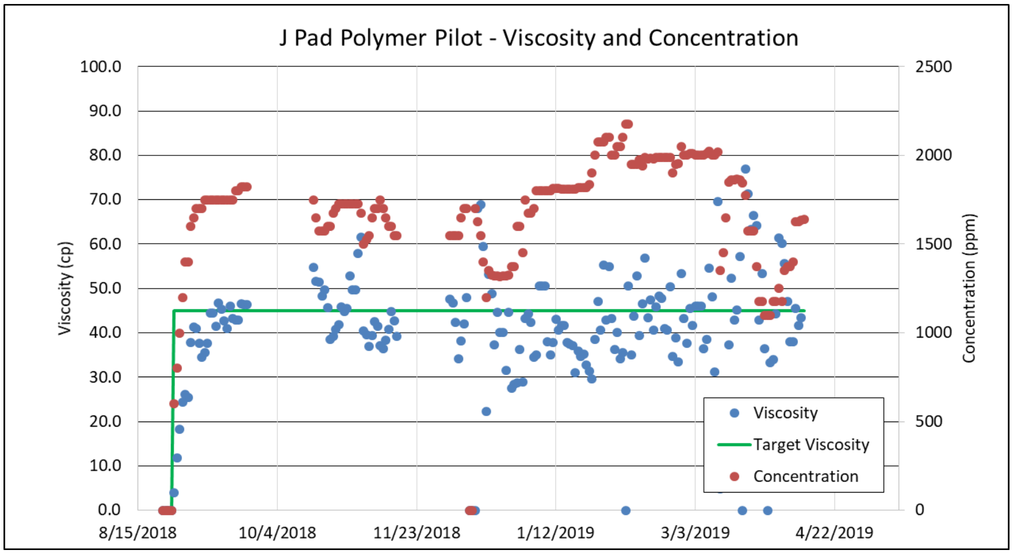

Figure 7. Polymer concentration and viscosity

The water used for making polymer solution is produced from a source water well (J-02) completed in the Prince Creek formation overlying the Ugnu formation which contains relatively fresh water supply with total dissolved solids of 2600 milligram per liter and total hardness of 280 milligram per liter. Shortly after polymer start up, we noticed that the source water contains more hydrocarbon gas than expected forcing us to stop injection and modify the electrical components to meet the Class I Division 2 standards (API RP 500 – Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2). In November 2018, we had to shut down the PSU again to repair the augur motor and replace the worn out cranks and bearings on the injection pumps.

Results and Discussion

Step Rate Tests. Several step rate tests were performed on both injectors before and after polymer startup to assess the water versus polymer injectivity. Figures 8 and 9 depict the pre-polymer step rate test results for J-23A and J-24A respectively. Downhole gauges were installed for these tests to eliminate the effect of friction pressure. Analyses show that the water injectivity of both wells are approximately 3.2 barrels per day per psi (bpd/psi) (inverse of the slope of the pressure versus rate plot).

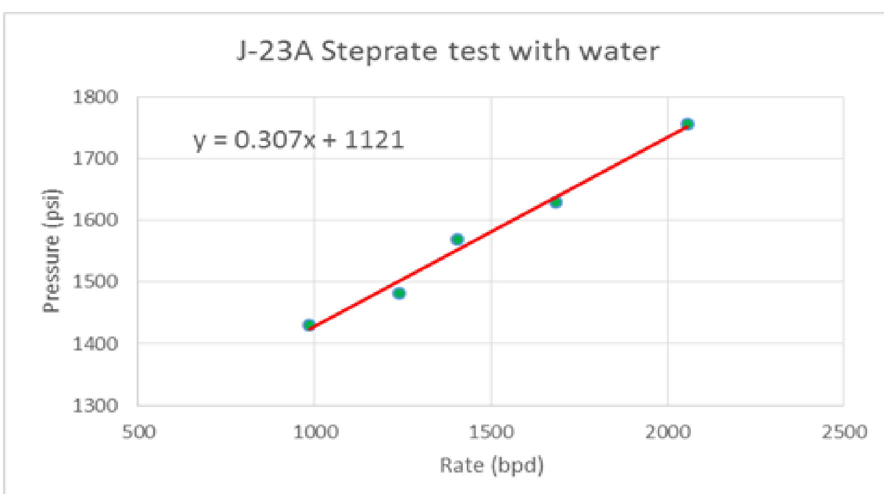

Figure 8. J-23A Pre-polymer step rate test results

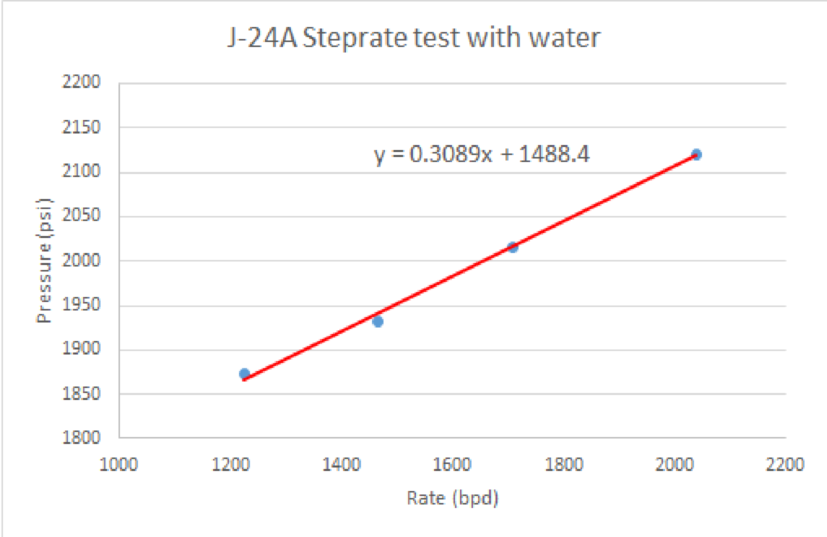

Figure 9. J-24A Pre-polymer step rate test results

On October 5th, 2018, 5 weeks after polymer start up, downhole gauges were run again into the two injectors to perform post-polymer step rate and pressure falloff (PFO) tests. Figure 10 shows the results of J-23A post-polymer step rate test. The data show a nice linear relationship between the injection pressure and injection rate indicating that the formation was not fractured at the time. The injectivity with polymer is estimated to be 3.1 bpd/psi compared with 3.2 bpd/psi with water. Polymer injectivity stayed approximately the same although the viscosity of the polymer was 45 times higher than that of water, which indicates that injectivity was dominated by fluid mobility deep in the reservoir rather than that in the wellbore vicinity.

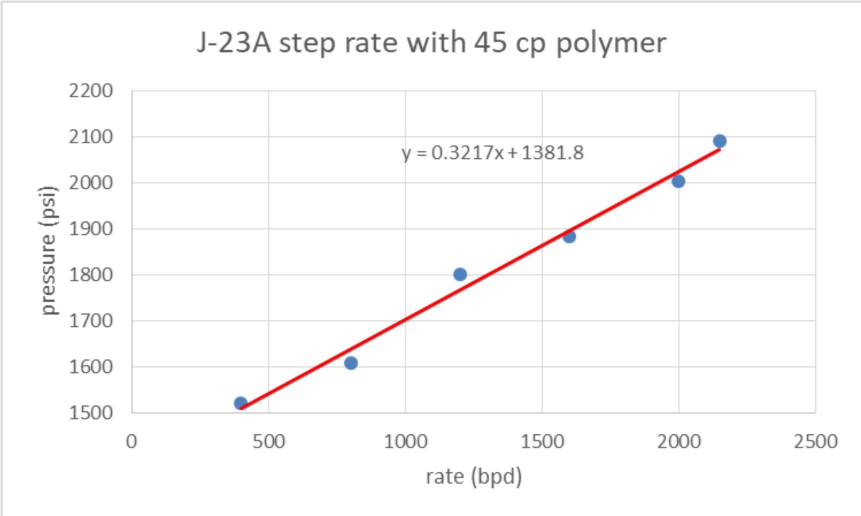

Figure 10. J-23A post-polymer step rate test results

Figure 11 shows the results of J-24A post-polymer step rate test. Again, the data show a nice linear relationship between the injection pressure and injection rate indicating that the formation was not fractured at the time. The injectivity with polymer is estimated to be 4.5 bpd/psi compared with 3.2

bpd/psi with water. This apparent increase in injectivity was most likely due to the transient effect since the post polymer step rate test was conducted immediately after a 24 day shut in during which reservoir pressure declined due to the ongoing production from the offset producer J-27.

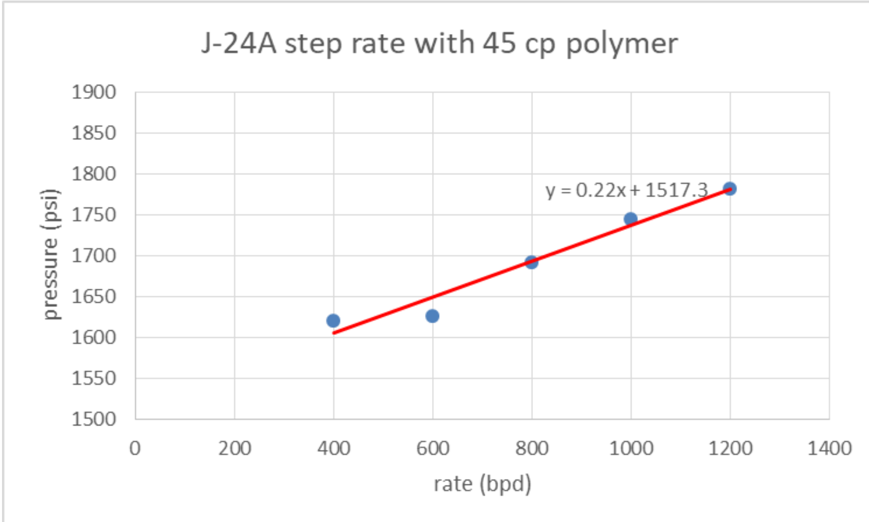

Figure 11. J-24A post-polymer step rate test results

Pressure Falloff Tests. PFO tests were performed in both injectors, J-23A and J-24A, prior to and 3 months after polymer injection started. Figure 12 shows a comparison between the pre and post-polymer PFO pressure derivative plots for J-23A. The sharp increases in pressure derivative data (approximately 10 hours for pre-polymer PFO and 20 hours for post Polymer PFO) was caused by the freeze protection operations in which some diesel/xylene mixture was pumped into the wellbore to prevent the wellbore from freezing up during the shutdown.

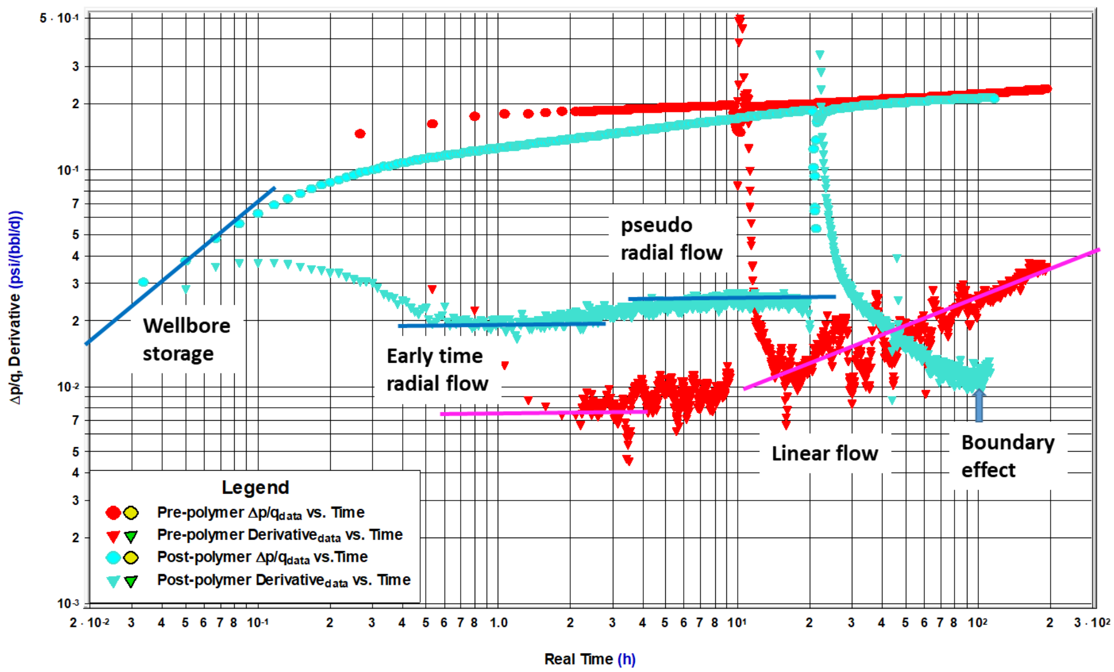

Figure 12. Comparison of J-23A pre and post-polymer PFO tests.

Both PFO tests show early time radial flow regimes, but only the pre-polymer PFO shows a linear flow regime as expected from a horizontal injector. Instead, the post polymer PFO show an apparent pseudo radial flow regime before the freeze protection. The late time data after the freeze protection might have been affected by the offset producers which were left on line during the PFO test. This indicates that the injected polymer might be entering a small section of the wellbore rather than evenly distributed along the 5000 ft horizontal wellbore. The early time pressure derivative data indicate that, post polymer injection, the mobility of the reservoir fluid near wellbore is approximately 2.5 times lower than that of water although the polymer viscosity is 45 times higher than water. This is likely due to polymer being diluted by the previously injected water in the reservoir.

Figure 13 shows the comparison between the pre and post-polymer PFO tests for J-24A. The diagnostic plot shows that both pre- and post-polymer PFO tests are dominated by linear flow regimes. The main difference between the two tests is that the near wellbore mobility post-polymer injection is about 2.5 times lower than that of water similar to what is observed in J-23A. However, one should not expect this number to stay constant with time. The magnitude of the decrease in mobility should change as more and more polymer is injected into the reservoir. Another interesting observation is that the late time pressure derivative data of the two PFO tests seem to merge together because fluid mobility deep in the reservoir is the same before and after the start of polymer injection.

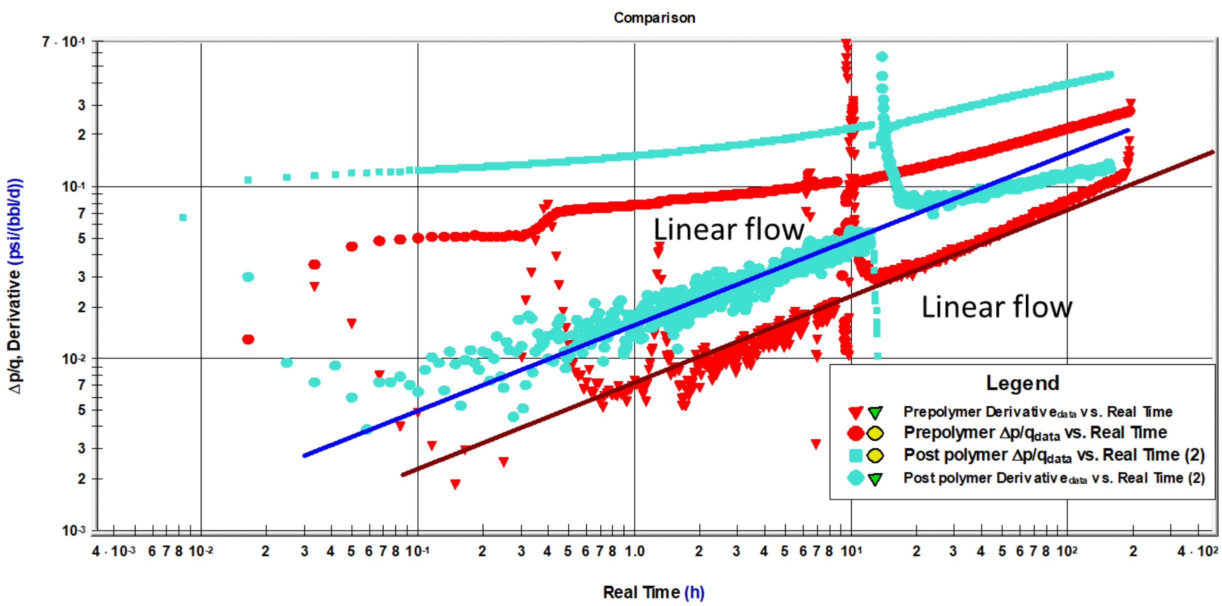

Figure 13. Comparison of J-24A pre and post-polymer PFO tests.

Long-term Injectivity. Figure 14 shows the injection rate and wellhead injection pressure of J-23A since the start of the PSU on August 24th, 2018. The PSU was on water injection for the first 4 days and then switched to polymer on August 28th. The injection rate has been kept constant at approximately 2200 barrels per day (bpd) for the most part while the wellhead pressure stayed at or below 500 psi for nearly five months and then started to creep up, indicating that the injectivity is decreasing as the reservoir is filled with polymer. Current injection pressure is approximately 800 psi.

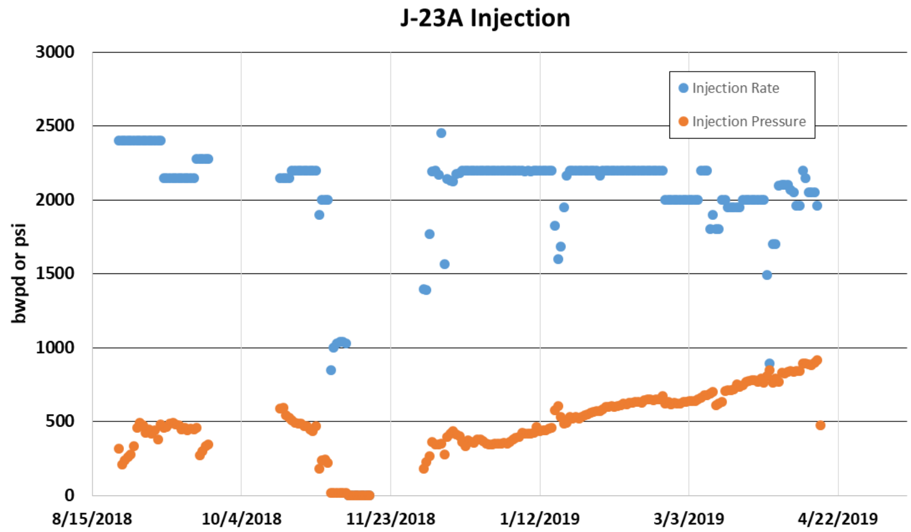

Figure 14. J-23A injection performance

Figure 15 shows the injection performance of J-24A. The polymer injection rate had to be reduced from 1200 bpd to 600 bpd by February 2019 to keep the injection pressure below the initial target pressure of 700 psi, which translates to a pressure gradient of 0.63 psi/ft, to avoid fracturing the formation. However, to catch up on the reservoir voidage replacement, we decided to increase the target pressure to 800 psi (0.66 psi/ft) in March 2019 which is approximately at the formation fracture pressure. From now on, the plan is to keep the injection pressure slightly above the fracture pressure if necessary to achieve the target injection rate.

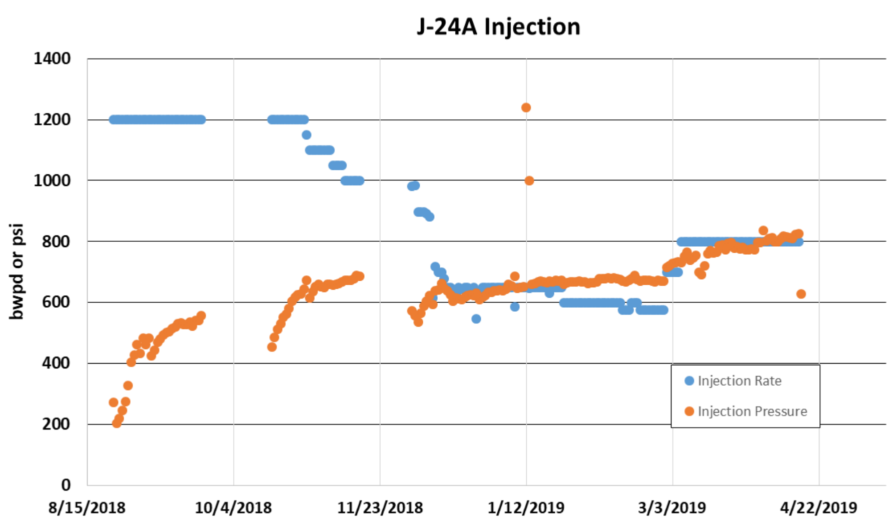

Figure 15. J-24A injection performance

Figure 16 is a Hall Plot for both J-23A and J-24A (Hall 1963) during polymer injection which plots the integration of the differential pressure between the injector and the reservoir versus cumulative water injection. The data would form a straight line if the injectivity stays constant over time, curve up if the injectivity decreases over time and vice versa.

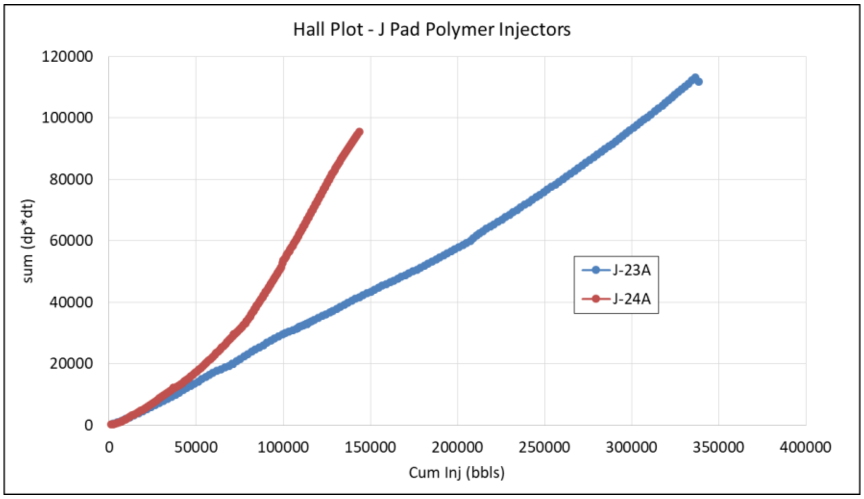

Figure 16. Hall plot during polymer injection

As can be seen from Figure 16, the injectivity of J-23A first stayed constant until the cumulative injection reached 100,000 barrels, then increased slightly until the cumulative injection reached 210,000 barrels, and finally started to decrease as evidenced by the increase in the slope. Whereas, the injectivity of J-24A was decreasing as indicated by the constant increase in the slope. However, J-24A injectivity was increased recently by raising the injection pressure to formation fracture pressure.

As of the end of March 2019, a total of approximately 200,000 and 82,000 lbs of polymer has been injected into J-23A and J-24A, respectively. Cumulatively 510,000 barrels of polymer solution has been injected which represents approximately 3% of the total pore volume in the 2 flood patterns.

Injection Profile Logs

Prior to the start of polymer injection, injection profile logs (IPROF) were conducted to determine if there are fast connections between the injectors and the producers. Injection profile control treatments would be required before polymer injection if fast connections were identified. Two sets of IPROF's were performed in each injector, one in 2017 and another in August 2018. The results of J-23A IPROF are presented in Figure 17 in which the blue bars indicate percentage of injected water entering into each ICD in 2017 and the red bars depicts the injection profile in 2018. The black arrows indicate the location of swell packers.

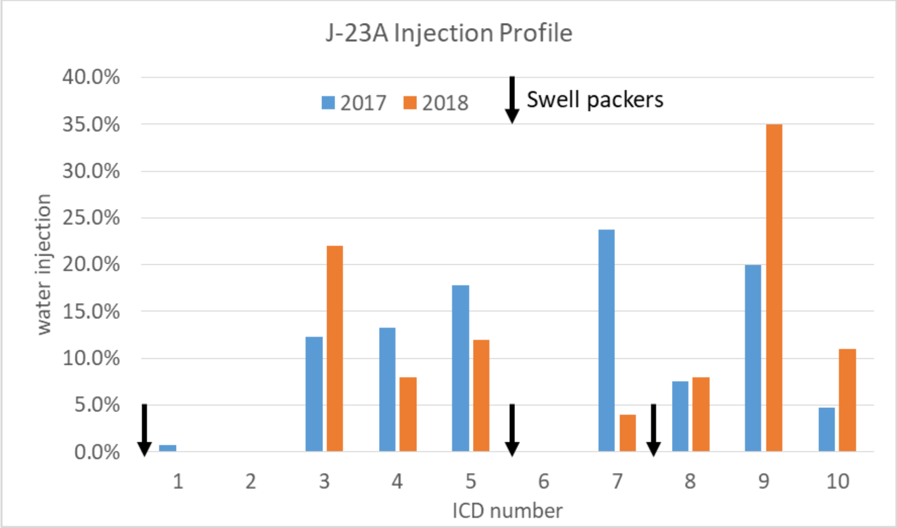

Figure 17. J-23A injection profile log

Figure 17 shows that ICD #1 in well J-23A was only taking 1% of the water injected in 2017 and that ICD's #2 and #6 were not taking any water. Similarly in 2018, ICD's #1, #2 and #6 were not taking any water. It is likely that these three ICD's are plugged up by the dirty produced water that was injected into J-23A from June 2016 to February 2017 before switching to clean source water. However, since the annulus between the sand face and the liner was open, water could distribute along the wellbore even if some ICD's were plugged as long as other ICD's in the same segment were open. The IPROF data show that the first segment was taking more than 40% of the total water injected into J-23A in both 2017 and 2018. The second segment was taking 24% of water injected in 2017 but only taking 9% in 2018, while the third segment was taking more than 30% in both logs.

Figure 18 shows the results of the J-24A IPROF which indicates that all segments of J-24A were taking water and that no thief zones were apparent. Incidentally, J-24A came on line the same day as the J-02 source water well in February 2017, hence never injected dirty produced water. Based on the IPROF results, no profile control treatment was deemed necessary before the start of polymer injection.

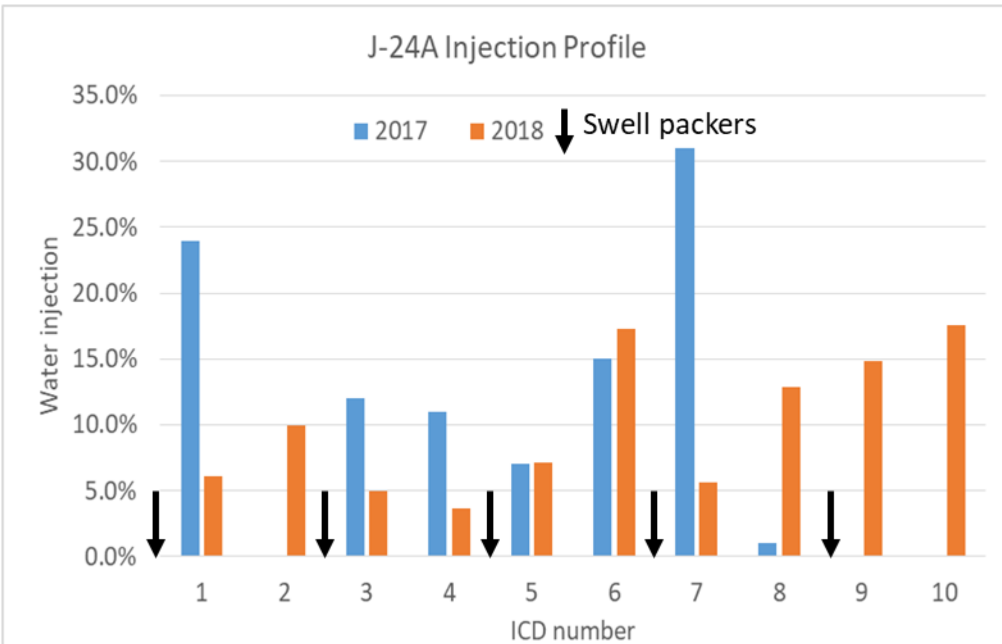

Figure 18. J-24A injection profile log

Tracer Tests. A pre-polymer tracer test was conducted 25 days prior to the start of polymer injection to define the waterflood breakthrough timing. Two different tracers named T-140C and T-140A were pumped into injectors J-23A and J-24A, respectively, on August 3, 2018. Produced water samples were taken weekly from producers J-27 and J-28 and analyzed to detect tracer concentration and the results are shown in Figure 19. Tracer T-140C was first observed in J-27, 70 days after injection and the tracer concentration reached the peak at 155 days indicating that communication between injector J-23A and producer J-27 was strong. Tracer T-140C from injector J-23A first appeared in producer J-28 103 days after injection and the concentration increased to 5 parts per billion days after injection. Tracer T-140A from injector J-24A first appeared in producer J-27 140 days after injection but the concentration is still less than 1 parts per billion 7 months after injection, indicating poor communication between the well pair.

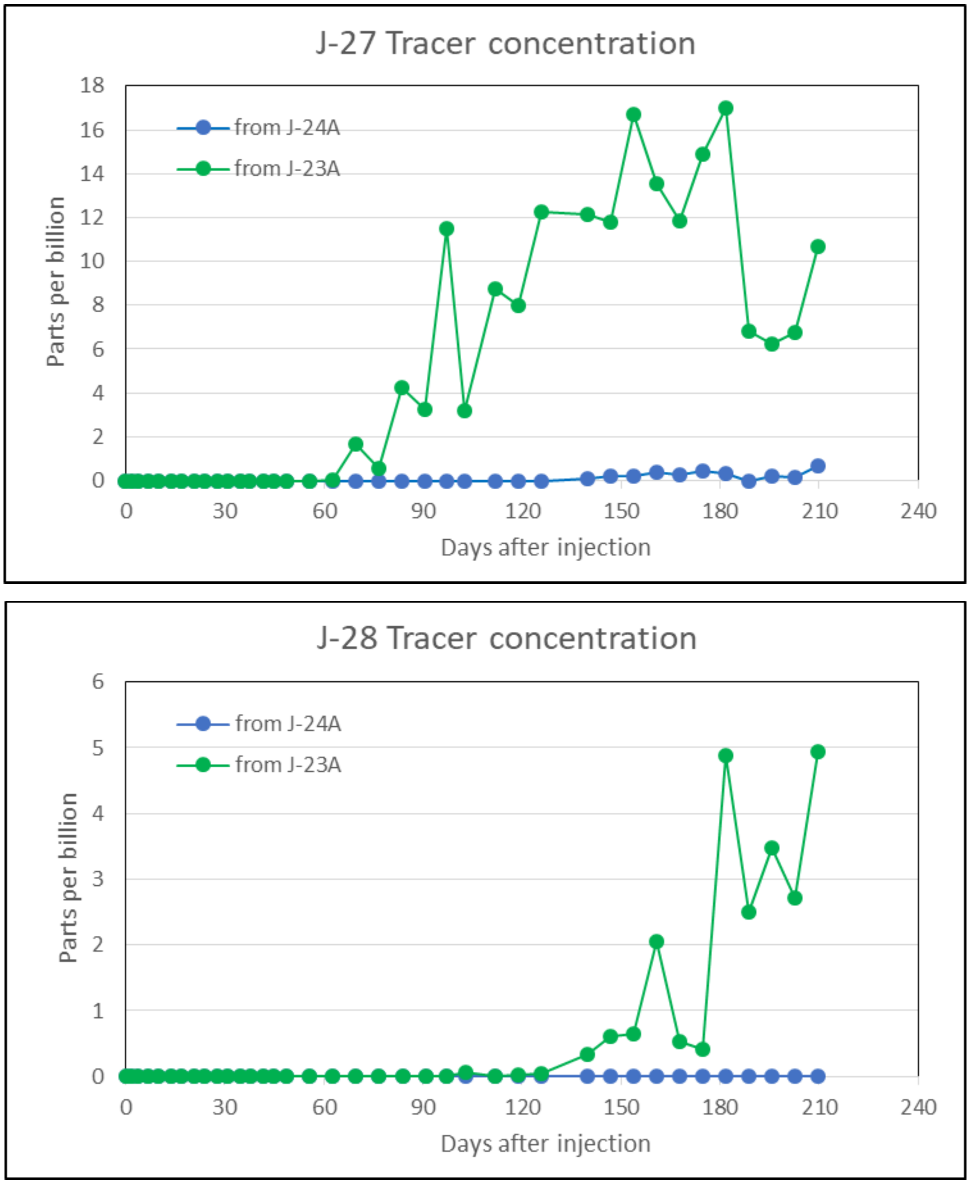

Figure 19. Tracer concentrations in produced water

Production Response.

Figure 20 presents the production data of J-27 before and after the start of polymer injection. As can be seen, the water cut (light blue) decreased from approximately 65% to less than 50% in the first 6 weeks after polymer injection and then started to creep up to about 55% by the end of March 2019 which is 7 months after the start of the polymer injection. Unfortunately some errors occurred in the well test facility which erroneously gave high oil production rate shortly after polymer startup. However, the trend of water cut is believed to be representative. The total liquid rate (dark blue) has been decreasing due to the lack of injection support with polymer since the voidage replacement ratio has been less than 1.0 since the start of polymer injection.

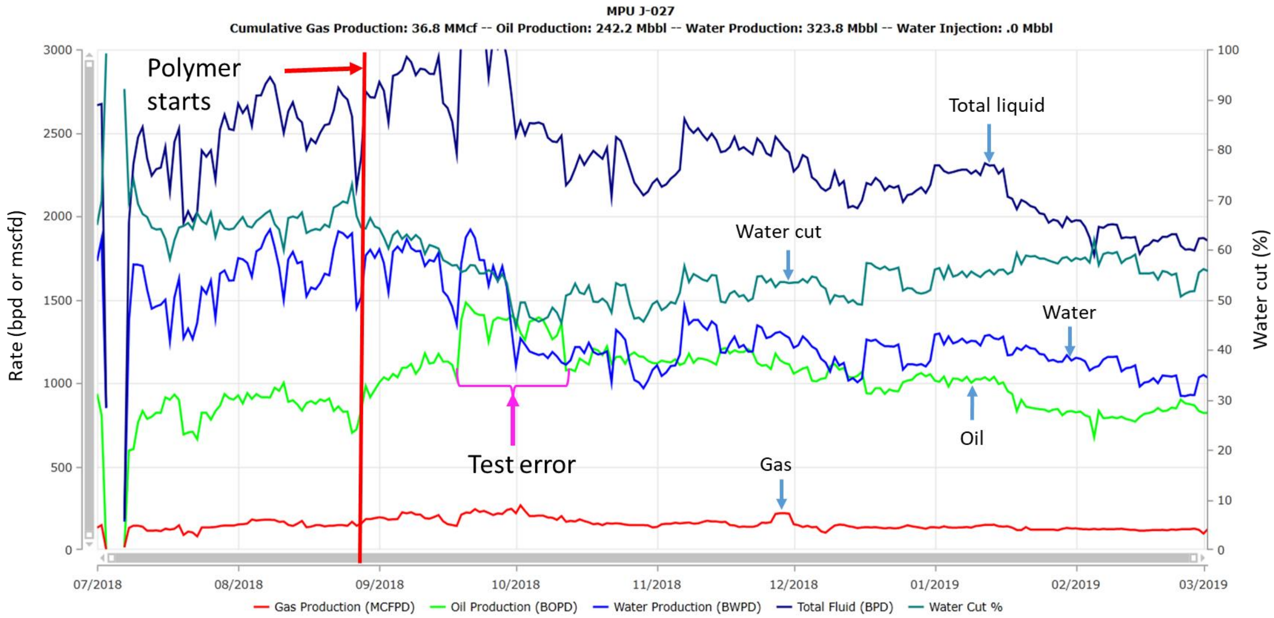

Figure 20. J-27 production response

Figure 21 presents the production data of J-28 before and after the start of polymer injection. Similar to J-27, the water cut decreased from approximately 70% to 45% in 2 months and then started to creep up to about 57% by the end of March 2019. The total liquid rate has also been declining due to the lack of injection support. It is still too early to quantify the amount of incremental oil production due to polymer injection since the total polymer solution injected into the reservoir is still less than 3% of the total pore volume (TPV) in the flood patterns. We expect to be able to confidently define incremental oil recovery after 10-12% TPV of polymer solution has been injected.

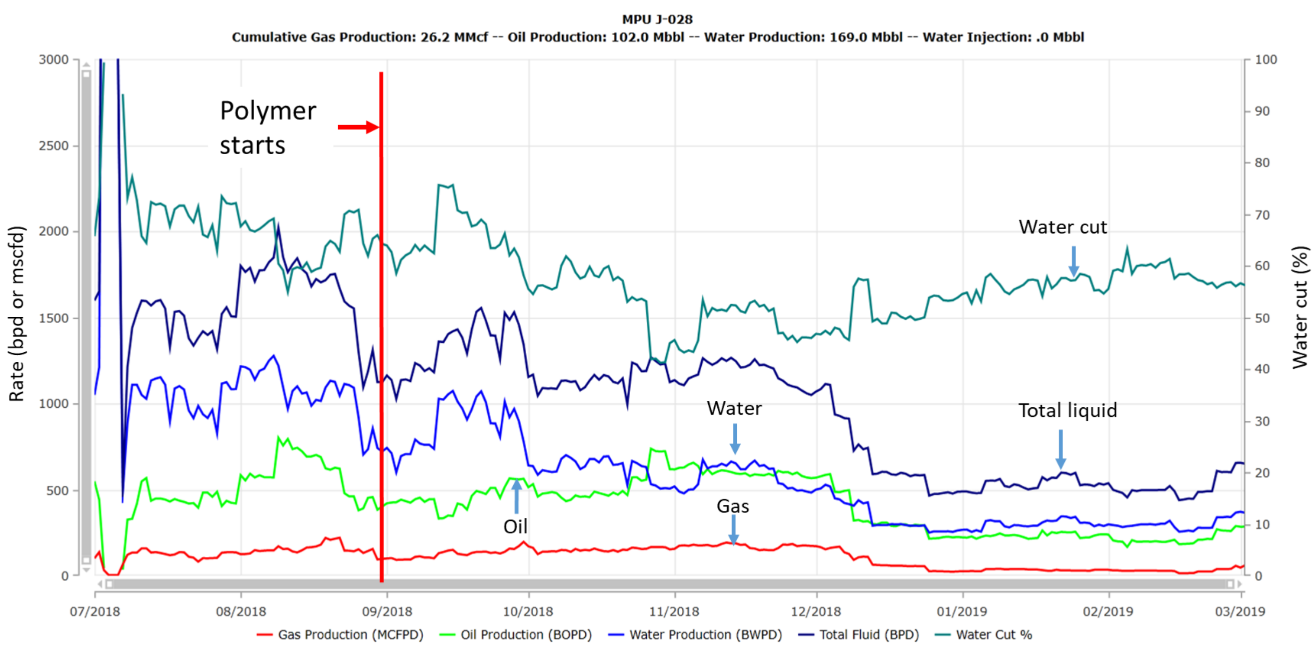

Figure 21. J-28 production response

Since the start of polymer injection, produced water samples have been collected weekly and analyzed onsite using the clay flocculation test, as well as in the laboratory via nitrogen-fluorescence water composition analyses to detect the presence of produced polymer in the production stream. As of the end of March 2019, seven months after the start of polymer injection, no polymer has been observed in the production stream, while waterflood breakthrough time is about 3 months from injector J-23A to producer J-27 based on both production data and tracer test. This indicates that polymer significantly delays breakthrough time which will lead to increased sweep efficiency.

Conclusions

It has been 8 months since the start of polymer injection into the 2 horizontal injectors, J-23A and J-24A, completed in the Schrader Bluff heavy oil reservoir at Milne Point field on the North Slope of Alaska. Below is a summary of the observations to date:

1. The custom designed and manufactured polymer slicing unit is operating as expected to mix and pump polymer after minor modifications to accommodate the higher than expected hydrocarbon gas in the source water. Lesson learned was that operator involvement earlier in design or improved vendor understanding of end user capabilities/needs would likely have resulted in a shorter tie-in window and lower costs.
2. Step rate and pressure falloff tests show that short term polymer injectivity of the horizontal injectors are similar to their water injectivity prior to the polymer startup indicating that injectivity is mostly dominated by fluid mobility deep in the reservoir rather than that in the wellbore vicinity.
3. One of the two injectors (J-23A) is able to inject 45 cP polymer at target injection rate of 2200 bpd, while the injection rate of the other injector (J-24A) decreased to half of the target rate of 1200 bpd to keep the bottom pressure below fracture pressure. Long term injection data indicate that polymer injectivity has been decreasing in both injectors as the reservoir is filled by polymer. It becomes necessary to raise the injection pressure to slightly above formation fracture pressure to achieve the target injection rates.
4. No polymer has been observed in the production stream seven months after the start of polymer injection compared with a 3-month breakthrough time with waterflood. This indicates that polymer significantly delays breakthrough time which will lead to increased sweep efficiency.
5. It is too early to quantify incremental oil recovery from polymer injection since only less than 3% TPV of polymer solution has been injected into the reservoir to date. However, the decreasing water cut trend is encouraging.

Nomenclature

ANS	Alaska North Slope
ANSFL	Alaska North Slope Field Laboratory
API	American Petroleum Institute
bbl	Barrel
bpd	Barrels per day
BOPD	Barrels Oil per Day
BWPD	Barrels of Water Per Day
cP	Centipoise
EOR	Enhanced Oil Recovery
ft	Feet
HO	Heavy oil
HPAM	Hydrolyzed polyacrylamide

ICD	Injection control device
IPROF	Injection profile logs
KRU	Kuparuk River Unit
MBD	Thousand barrels per day
MCFPD	Thousand cubic feet per day
MD	Measured depth
md	Milli-Darcy
MPU	Milne Point Unit
OOIP	Original Oil in Place
PFO	Pressure Falloff
PPM	Parts Per Million
PBU	Prudhoe Bay Unit
psi	Pound per squire inch
PSU	Polymer Slicing Unit
PV	Pore Volume
TVD	True vertical depth
TPV	Total Pore Volume
VRWAG	Viscosity Reduction Water Alternating Gas
WAG	Water Alternating Gas

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