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Quarterly Research Performance Progress Report

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Prime Recipient Type	Not for profit organization
Project Title	**FIRST EVER FIELD PILOT ON ALASKA'S NORTH SLOPE TO VALIDATE THE USE OF POLYMER FLOODS FOR HEAVY OIL EOR a.k.a ALASKA NORTH SLOPE FIELD LABORATORY (ANSFL)**

University of Alaska Fairbanks

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1. ACCOMPLISHMENTS

a. Project Goals

The overall objective of this project is to perform a research field experiment to validate the use of polymer floods for heavy oil Enhanced Oil Recovery (EOR) on Alaska North Slope.

The main scientific/technical objectives of the proposed project are:

1. Determine the synergy effect of the integrated EOR technology of polymer, low salinity water, horizontal wells, and conformance treatments (e.g., gels), and its potential to economically enhance heavy oil recovery.
2. Assess polymer injectivity into the Schrader Bluff formations for various polymers at various concentrations.
3. Assess and improve injection conformance along horizontal wellbore and reservoir sweep between horizontal injectors and producers.
4. Evaluate the water salinity effect on the performance of polymer flooding and gel treatments.
5. Optimize pump schedule of low-salinity water and polymer.
6. Establish timing of polymer breakthrough in Schrader Bluff N-sands.
7. Screen an optimized method to control the conformance of polymer flooding at the various stages of the polymer flooding project.
8. Estimate polymer retention from field data and compare with laboratory and simulation results.
9. Assess incremental oil recovery vs. polymer injected.
10. Assess effect of polymer production on surface facilities and remediation methods.

The technical tasks proposed in these studies will focus on the following: (1) optimization of injected polymer viscosity/concentration and quantification of polymer retention via laboratory scale experiments; (2) optimization of injection water salinity and identification of contingencies for premature polymer breakthrough via laboratory scale experiments and numerical analyses; (3) reservoir simulation studies for optimization of polymer injection strategy; (4) design and implementation of a field pilot test at Milne Point on ANS; (5) identification of effective ways to treat produced water that contains polymer, and finally (6) the feasibility of commercial application of the piloted method in ANS heavy oil reservoirs. The project milestones, and current milestone status are shown in **Table 3**.

b. Accomplishments

The primary focus of the research program, in these early stages, has been the initiation of the polymer injection in the already set aside injection wells J-23A and J-24A respectively. The accomplishments to date are summarized in the following bullet points:

- All sub-awards have been issued.

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- Initial Project Management Plan (PMP) completed and submitted to NETL on July 25th, 2018.
- Data Management Plan (DMP) completed and submitted to NETL on July 20th, 2018.
- Rock and fluid samples, and reservoir characterization data sent to university participants.
- Preliminary coreflooding tests have been initiated.
- Literature review on produced fluid treatment completed.
- Pre-polymer tracer and Production Falloff (PFO) tests completed.
- Polymer equipment installation and testing completed.
- Field polymer injection has commenced, and data on influent and effluent field parameters is being continuously collected.

Since the official project start date of June 1, 2018, three meetings have been held between the various project partners. Additionally, a formal presentation was made at the "Mastering the Sub-surface" meeting in Pittsburgh on August 16, 2018. The project kickoff meeting took place on August 22nd in Anchorage, Alaska at the premises of Hilcorp office where all the team members were present and very detailed discussions took place on each of the tasks as well as the overall project that consumed the entire day. Unfortunately, the team visit that was scheduled for the following day to actually see the Milne Point project site, the already installed polymer mixing and injection units, was canceled due to flight delays and potentially inclement weather conditions on the North Slope of Alaska. The site visit has been tentatively re-scheduled for spring 2019 at which time the polymer injection will be well underway.

The following summarizes the team's progress to date in relation to the various tasks and sub-tasks outlined in the Project Management Plan (PMP):

- Task 1.0 - Project Management and Planning

  PMP and DMP: Activity has been completed, per the dates shown above.

- Task 2.0 - Laboratory Experiments for Optimization of Injected Polymer Viscosity/Concentration and Quantification of Polymer Retention

1. Received oil, sand, and cores from Hilcorp.
2. Decided on two water compositions to use during the experiments (one for synthetic formation water, one for injection water).
3. Discussed problems of core integrity with team members (especially University of Alaska).
4. Discussed way forward on experiments (with University of North Dakota and Hilcorp).
5. Decided the first three experiments should be three sand pack studies to assess polymer retention with a) sand as received, b) cleaned (extracted with toluene) sand, and c) sand saturated with oil and driven to S_{or}.
6. Lined up methodology to analyzed produced polymer samples (from Hilcorp) for polymer and certain divalent cations.

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Activity is ongoing.

- Task 3.0 - Laboratory Experiments for Optimization of Injection Water Salinity and Identification of Contingencies in Premature Polymer Breakthrough in the Field

1. Experimental materials from Hilcorp were received, including crude oil, low salinity source water, nine clean core plugs, and a preserved full size core (**Table 1**).
2. The problem associated with the core samples was discussed with team members especially University of Alaska and Hilcorp. The unconsolidated nature of the cores was specified and special caution should be taken to the core integrity in any core treatment process.
3. The received crude oil may contain some water in the form of emulsions (see **Figure 1**). The oil quality and treatment technique was discussed with University of Alaska and New Mexico Tech.
4. The difficulties in achieving the residual oil saturation were discussed with team members, especially Randy Seright from New Mexico Tech.
5. In the next three quarters, Missouri S&T will be focused on optimization of injection water salinity. The enhanced oil recovery mechanisms of low salinity were collected. The main mechanisms involved are summarized as: (1) Multi-Ion Exchange which would alter the wettability of pore surface; (2) Rock mineral dissolution; (3) Fines migration, which may block pore-throats and decrease effective porosity but also possibly divert fluid flow and improve sweep efficiency; (4) Interfacial Tension (IFT) Reduction and accordingly capillary pressure reduction.
7. Detailed lab study schedule was set up after discussion with Hilcorp. Missouri S&T planned to run a couple of sandpack experiments and then core flooding tests to investigate the effect of salinity on residual oil saturation and oil recovery. The optimum salinity would be obtained from these experiments (see **Figure 2**).

Table 1 As received experimental materials.

Materials	Quantity	Notes
Core plugs	9	clean
OA-sand full size core	1	Preserved
Oil samples	~4 gal	Heavier, L-47 API = 17.2
	~4 gal	Lighter, B-28 API = 19
Low salinity source water	4 gal × 2	From J-02A wellhead

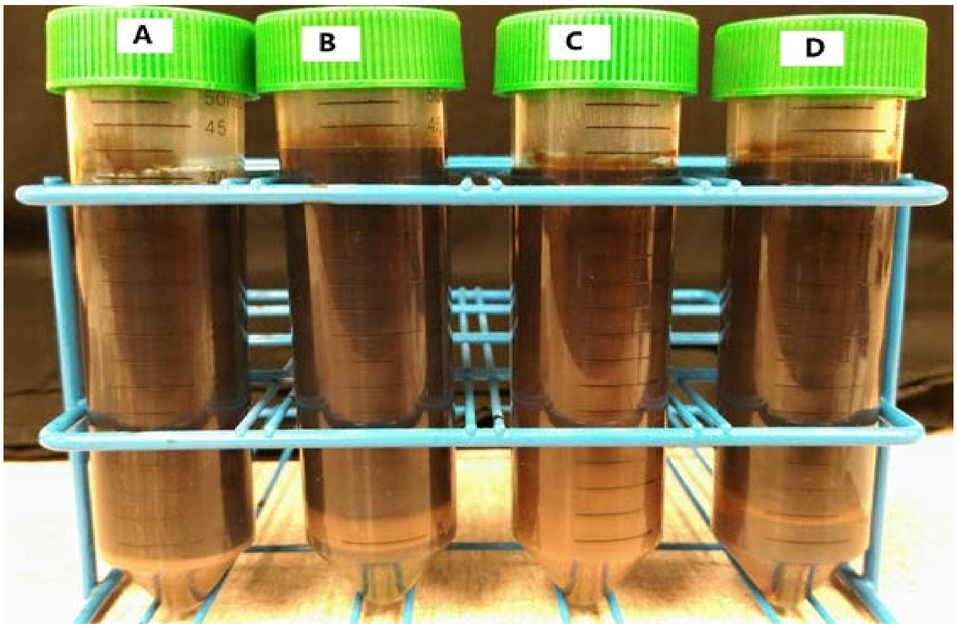


Figure 1 The received crude oil may contain water in the form of emulsions (A). B-28 crude oil received; (B). B-28 crude oil with addition of breaker; (C). L-47 crude oil received; (D). L-47 crude oil with addition of breaker.

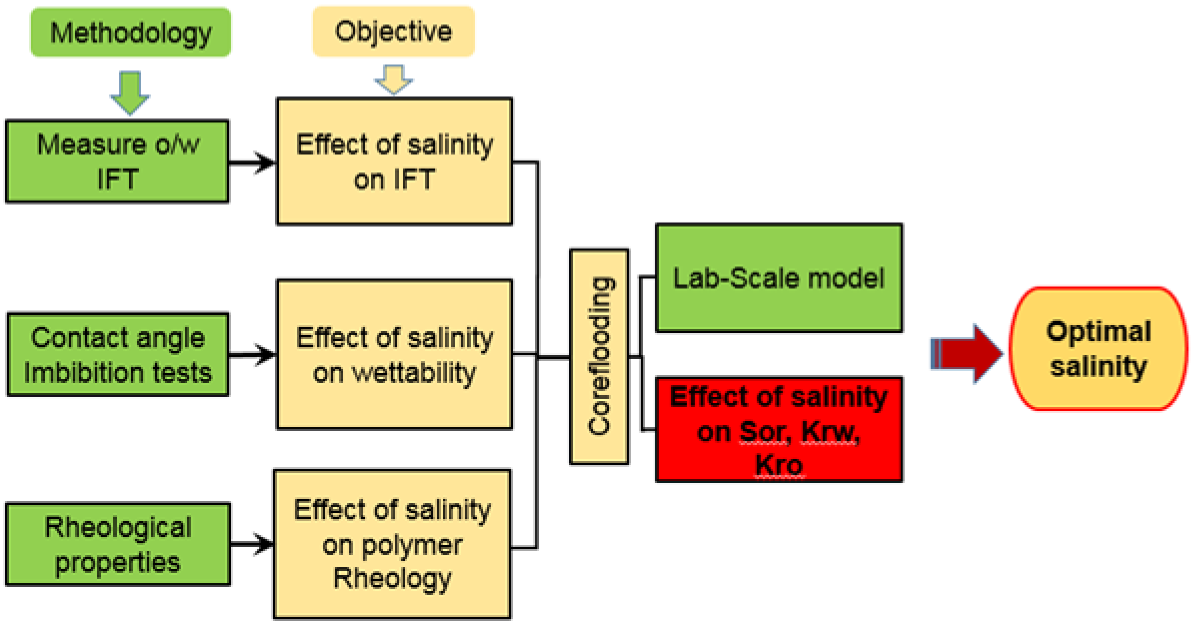


Figure 2 Optimization of injection water salinity.

Activity is ongoing.

- Task 4.0 - Reservoir Simulation Studies for Coreflooding Experiments and Optimization of Field Pilot Test Injection Strategy

Activities completed by UAF and Hilcorp include:
a. ***History matching technique selection.*** Ensemble-based methods have been determined to conduct the history matching for the field scale simulation model. To be specific, the iterative ensemble smoother (ES) algorithm is to be used assisting the history matching the waterflooding and the polymer flooding, estimation of reservoir properties, flooding performance optimization, and uncertainty analysis. Its updating equation is defined as:

$$m^{l+1} = \beta_l m_{pr} + (1-\beta_l) m^l - \beta_l C_M G_l^{\ T} \left(C_D + G_l C_M G_l^{\ T} \right)^{-1} \left[g\left(m^l\right) - d_{obs} - G_l \left(m^l - m_{pr}\right) \right] \quad (1)$$

where m_j^l and m_j^{l+1} denotes model parameters at l^{th} and $(l+1)^{th}$ iteration; β_l is the damping factor, 0< β_l <1; C_M is the covariance of model parameters; G_l are the integrated sensitivity matrix; C_D is the covariance of actual observation data; $g(\cdot)$ represents the reservoir simulator, i.e., CMG (version 2018) in this project; d_{obs} is the actual observation data at all time points; and T represents the transpose of a matrix. Given a reliable reservoir simulation model representing the target reservoir and corresponding production data, the parameterized inputs of the reservoir simulation models, e.g., permeability and multiphase relative permeability, can be iteratively estimated by using the updating equation.

***b. Static reservoir simulation model*.** Hilcorp geologists have constructed and provided a static reservoir model of the project area using existing data from seismic surveys, well logs, wellbore trajectories, and core analysis. The static model includes reservoir geologic structure, faults, formation tops and thickness of each layer, simulation grids, and porosity and permeability distributions. All these data are classified as Limited Rights Data since they have been collected and interpreted using the operator's private funding. Government and recipients must obtain written permission from Hilcorp Alaska, LLC prior to disclosure or use of these Limited Rights Data.

The collected reservoir description data have been organized and analyzed to develop a reservoir simulation model. By using the geological model, PVT data, rock-fluid data, well information, the reservoir simulation model has been generated. **Figure 3** shows the three-dimensional (3D) reservoir simulation model that illustrates the formation, faults, and horizontal well distribution. **Figures 4 and 5** display the permeability and porosity distribution of each layer in the reservoir simulation model, which will be correspondingly tuned in the history matching process.

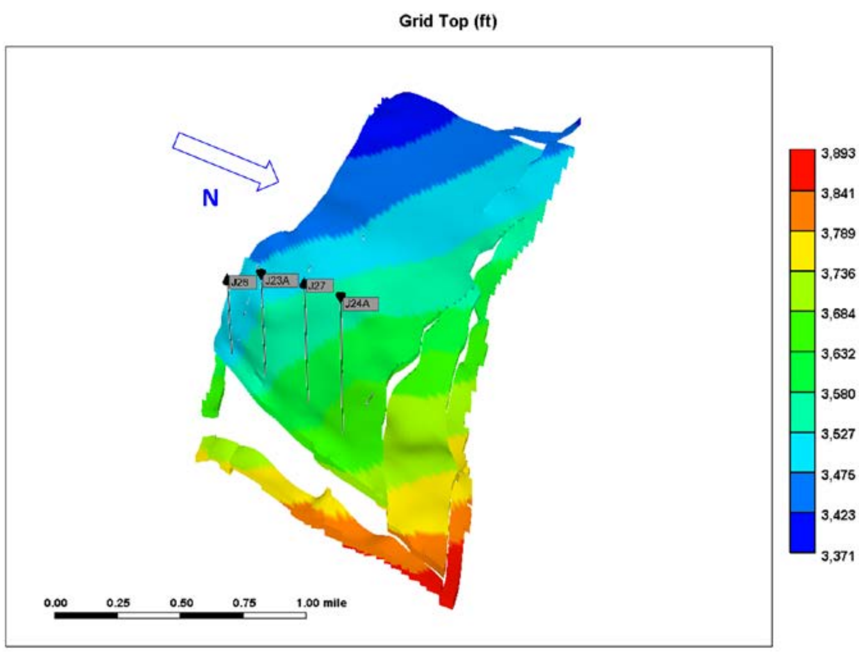
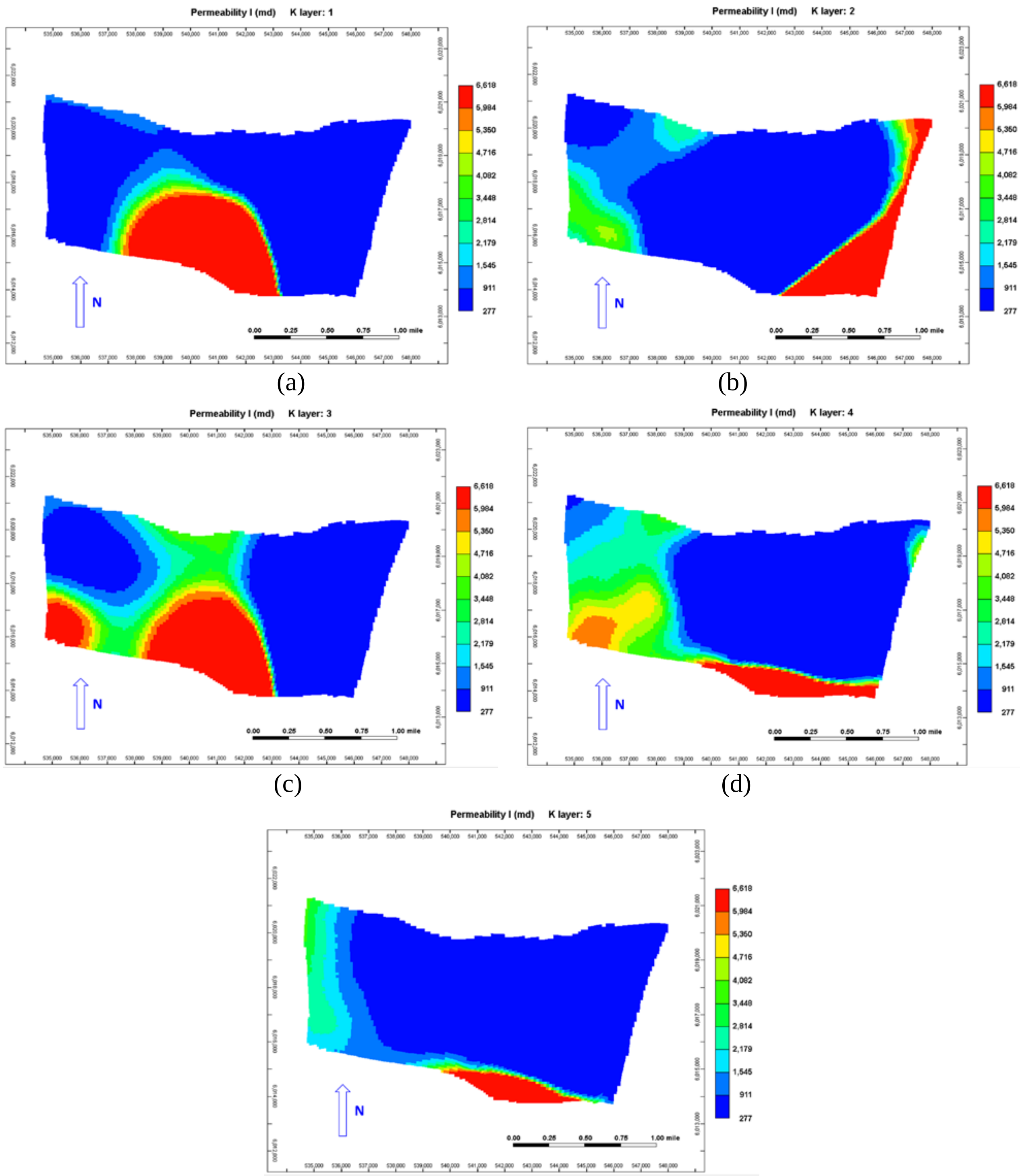
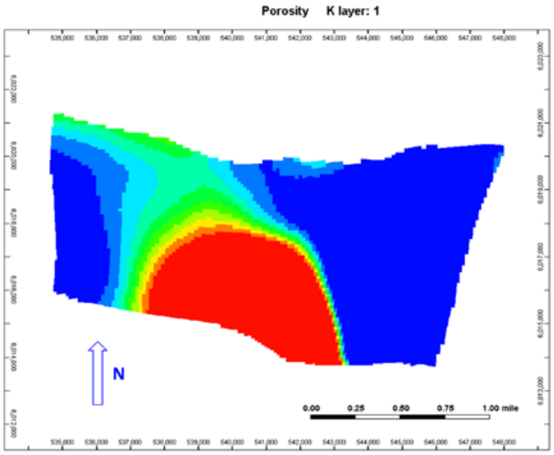


Figure 3 3D reservoir simulation model.

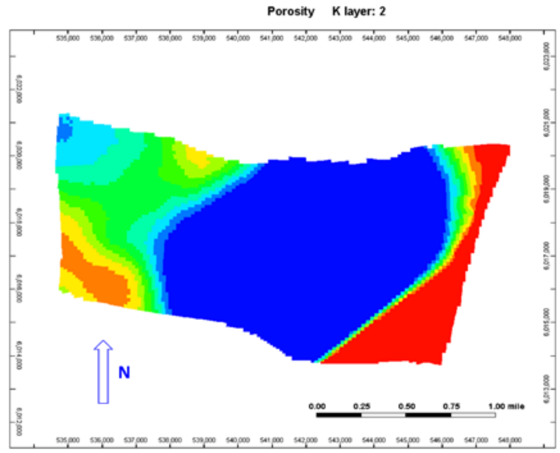


(a) (b) (c) (d) (e)

Figure 4 Permeability distribution of (a) layer #1, (b) layer #2, (c) layer #3, (d) layer #4, and (e) layer #5 in the reservoir simulation model.



(a)



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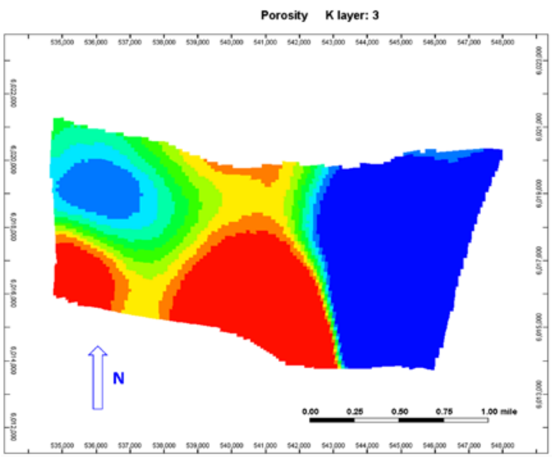
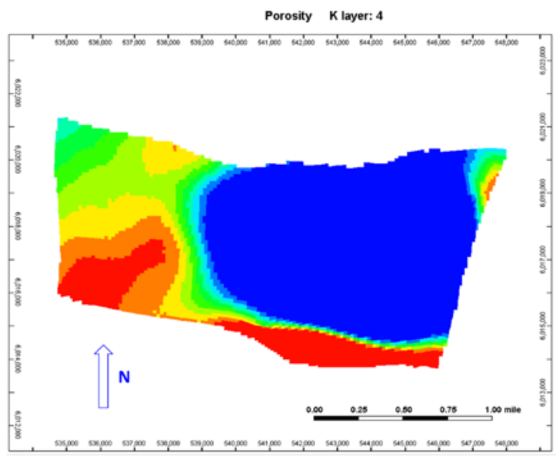
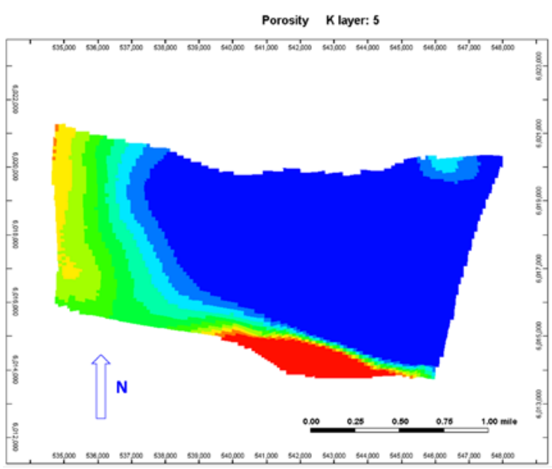


(c)



(d)



(e)

Figure 5 Porosity distribution of (a) layer #1, (b) layer #2, (c) layer #3, (d) layer #4, and (e) layer #5 in the reservoir simulation model.

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Activities completed by UND include:
a. Tentative cases for coreflooding history match design based on the core sample conditions, boundaries condition, and polymer well classification. Cases planned will be modified according to the actual laboratory experimental plan.

Preliminary cases for coreflooding history match design include:
1. Core flooding history with sand pack model, linear flow, 2-D Cartesian coordinate system.
2. Core flooding history with sand pack model, linear flow, 3-D corner point coordinate system.

Activity is ongoing.

- Task 5.0 - Implementation of Polymer Flood Field Pilot in Milne Point

Summary of progress related to the polymer injection is reported under accomplishments. **Figure 6** depicts the location of the test site at Milne Point field, which is located approximately 30 miles northwest of Prudhoe Bay Field on the North Slope of Alaska.

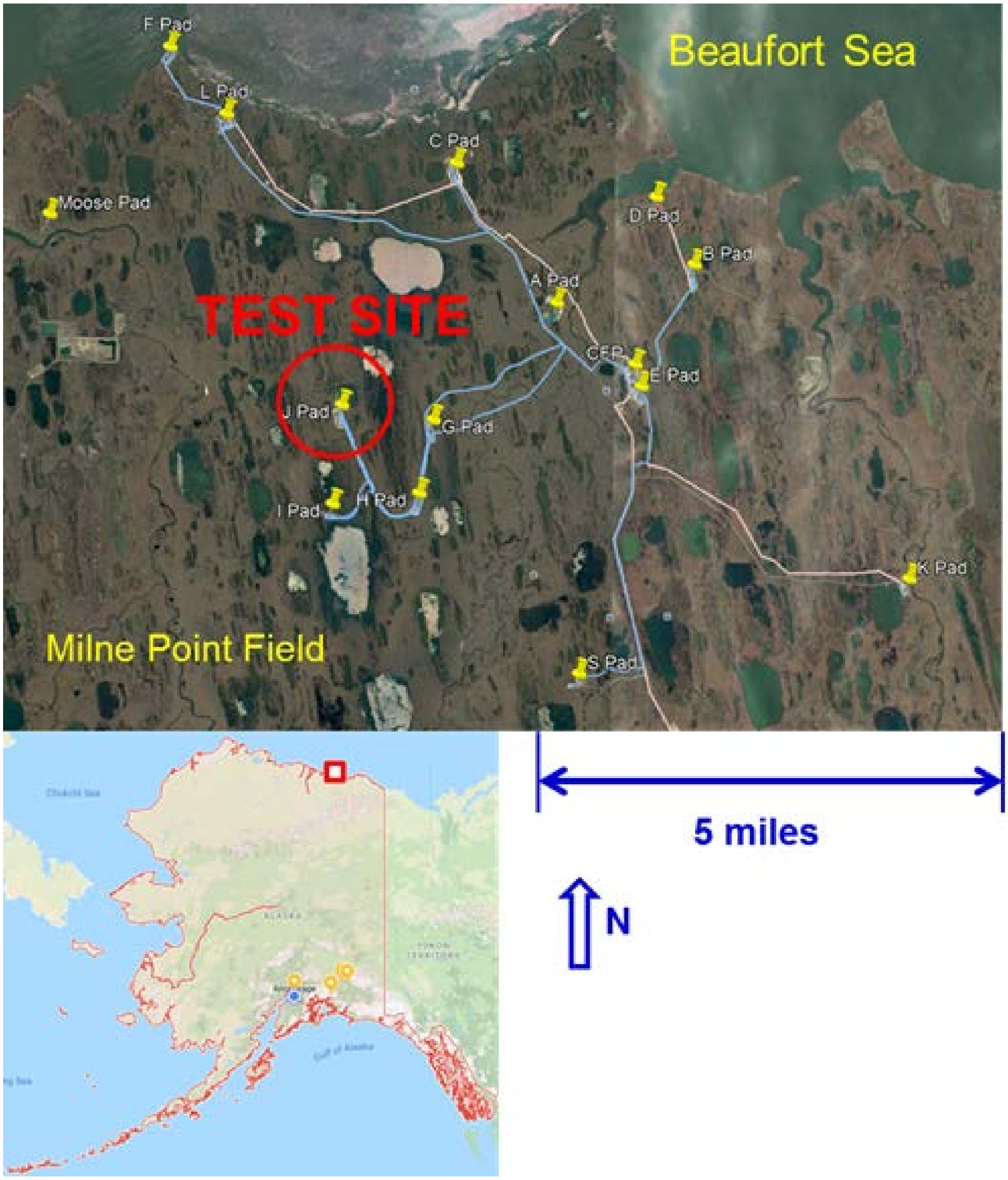

Figure 6 Details of the polymer pilot test site showing MPU J-pad.

Tracer tests:

Figure 7 is a map showing the horizontal well patterns of the project which consists of two injectors (J-23A and J-24A) and two producers (J-27 and J-28). The lengths of the horizontal wellbores are from 4200 to 5500 feet and the inter-well distance is approximately 1500 feet.

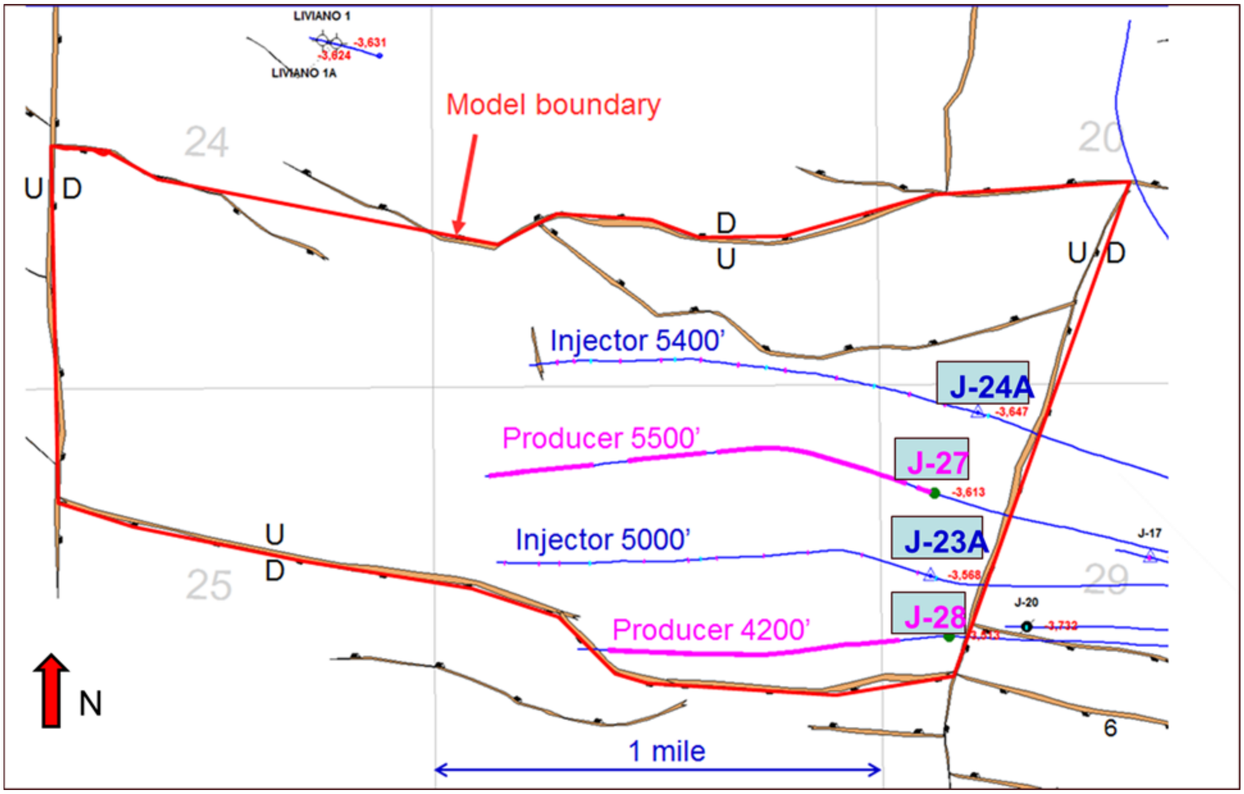

Figure 7 Project well patterns.

Pre-polymer tracer tests were conducted on August 3, 2018 by Tracerco. Tracer T-140A was pumped into well J-24A and tracer T-140C was pumped into well J-23A. Samples will be collected from the two producers, J-27 and J-28, 3 times per week in the first 2 weeks, 2 times per week from week 5 to week 8, and once per week thereafter.

The tracer breakthrough timing would be an indication of how long it would take water to travel from the injectors to the corresponding producers. It has been six weeks since the pre-polymer tracer injection date and no tracer production has been detected yet. A post polymer tracer test is planned to be performed 1-2 months after polymer injection has stabilized and the results will be compared with the pre-polymer tracer test.

Pre-polymer step rate and PFO:
Pressure falloff (PFO) and step rate tests were performed in mid-August using surface pressure gauges on each of the two injectors during water injection. However, it was found that the pressure data exhibited abnormal trend. Further investigations revealed that a surface check valve and possibly some downhole restrictions may be the culprits that caused the erroneous pressure readings.

To remediate this problem, downhole gauges were installed and additional PFO and step rate tests were performed after tying in the polymer skids on August 23rd. The test data and results of analysis will be reported in the next Quarterly Report.

Injection profile logs:
Figure 8 is a wellbore diagram for injector J-23A which is similar to that of J-24A. The injectors are completed with 4-½" liners equipped with injection control devices (ICD) and swell packers which divide the wellbores into segments. There are 10 ICD's installed in J-23A, each contain 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 limiting water flow into the thief zone.

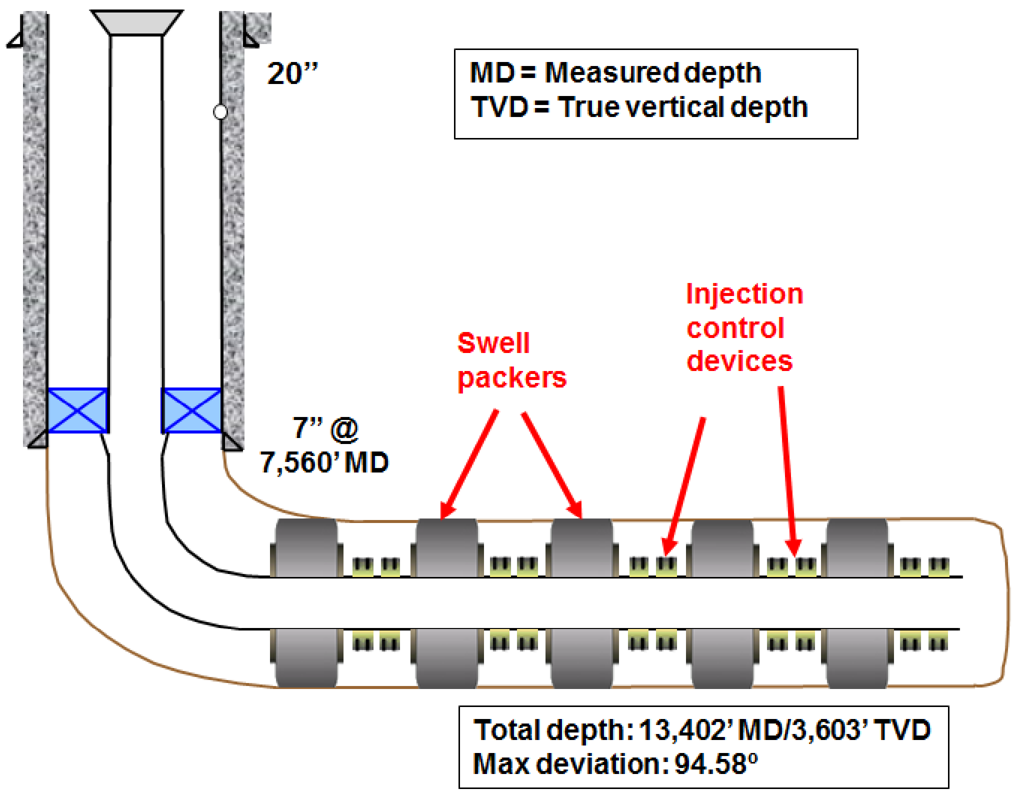

Figure 8 J-23A wellbore diagram.

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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 have been performed in each injector, one in 2017 with Hilcorp's private funding and another in August 2018 as part of this project. The results of both are presented in **Figures 9 and 10** for J-23A and J-24A respectively. 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.

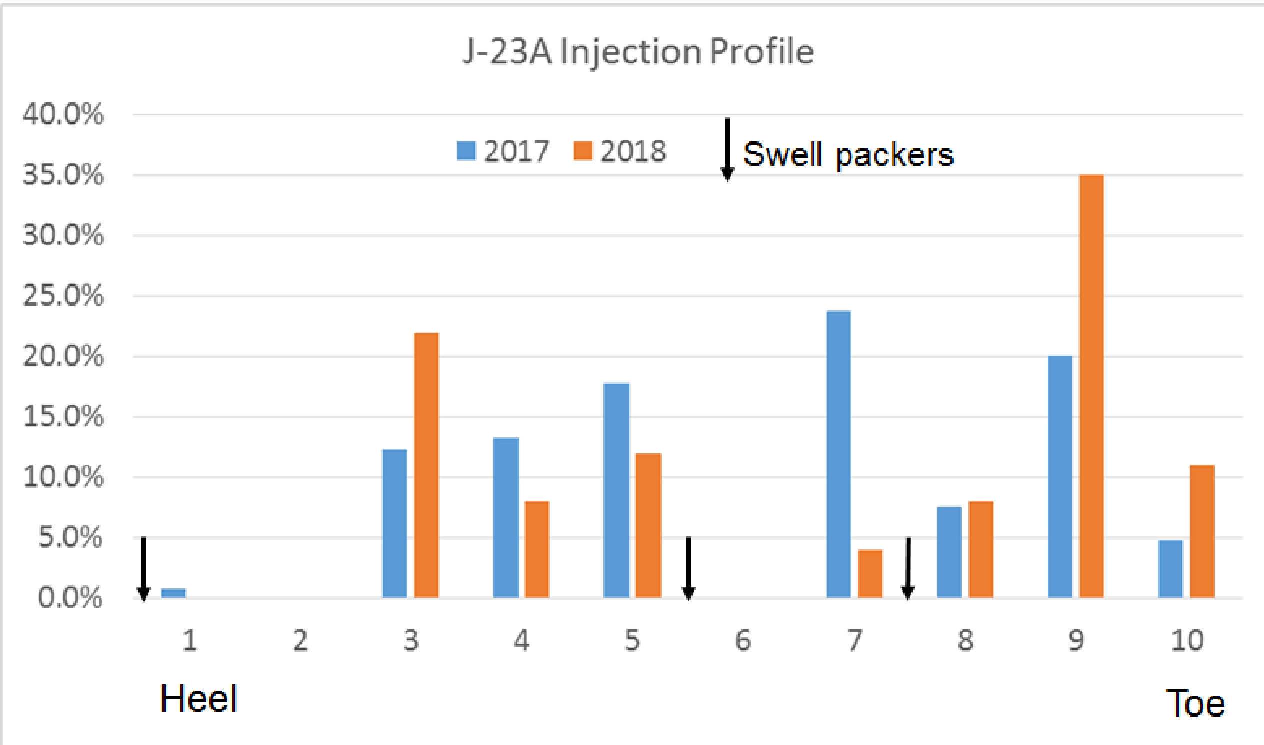

Figure 9 J-23A injection profiles.

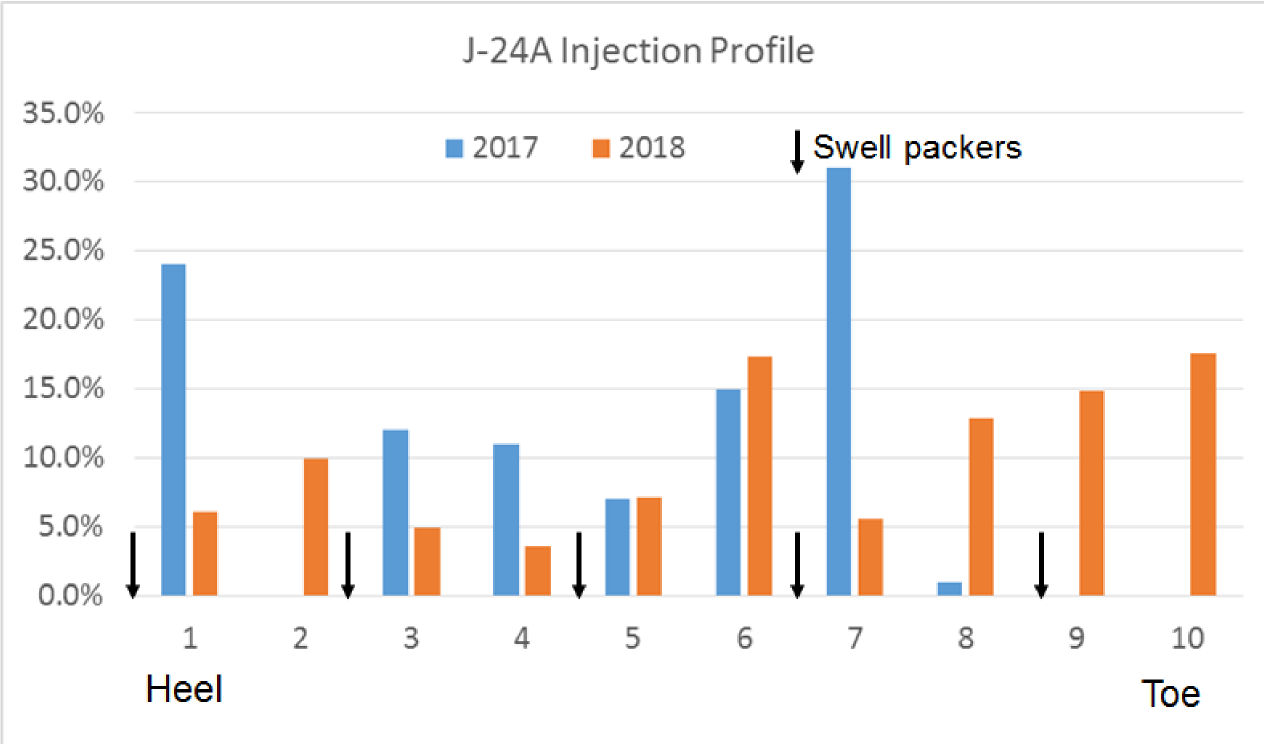

Figure 10 J-24A injection profiles.

Figure 9 shows that ICD #1 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 are not taking any water. However, each segment of the wellbore are taking water because other ICD's in the corresponding segment are open. Since the annulus between the sand face and the liner is open, water can distribute along the wellbore even if some ICD's are plugged as long as other ICD's in the same segment are open. The IPROF data show that the first segment is taking more than 40% of the total water injected in both 2017 and 218. The second segment was taking 24% of water injected in 2017 but only taking 9% in 2018, while the third segment are taking more than 30% in both logs. **Figure 10** indicates that all segments of J-24A are taking water and that no thief zones are apparent. Therefore, no profile control treatment is deemed necessary at this time.

Polymer injection startup:

The polymer mixing and pumping facilities named Polymer Skid Unit (PSU) were custom designed and manufactured for this project in Canada. As shown in **Figure 11,** 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 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 feed into the 3 triplex injection pumps in the pumping unit, one for each injector plus a spare.

Figure 11 Polymer injection unit on the J-pad.

The PSU arrived at the project site on June 29th and was installed and tested through July and August. On August 23rd, the PSU was tied in and started pumping water while waiting for the area injection order from Alaska Oil and Gas Conservation Commission (AOGCC). Polymer injection started on August 28, 2018 at 600 ppm ramping up every 24 hours to 800 ppm, 1000 ppm, 1200 ppm, 1400 ppm, 1600 ppm, 1650 ppm, 1700 ppm, and 1800 ppm. The initial target polymer viscosity is 45 cP based on preliminary reservoir simulation studies, which will be adjusted and optimized per laboratory and simulation results as they become available.

Figure 12 is a screen shot of the monitoring system showing the injection status on August 29, 2018. J-23A was injecting 2400 bpd at 250 psi tubing pressure and J-24A was injecting 1200 bpd at 300 psi. The flow rate of the mother solution was at 10.9 gallon per minute which was equivalent to 800 ppm polymer going downhole.

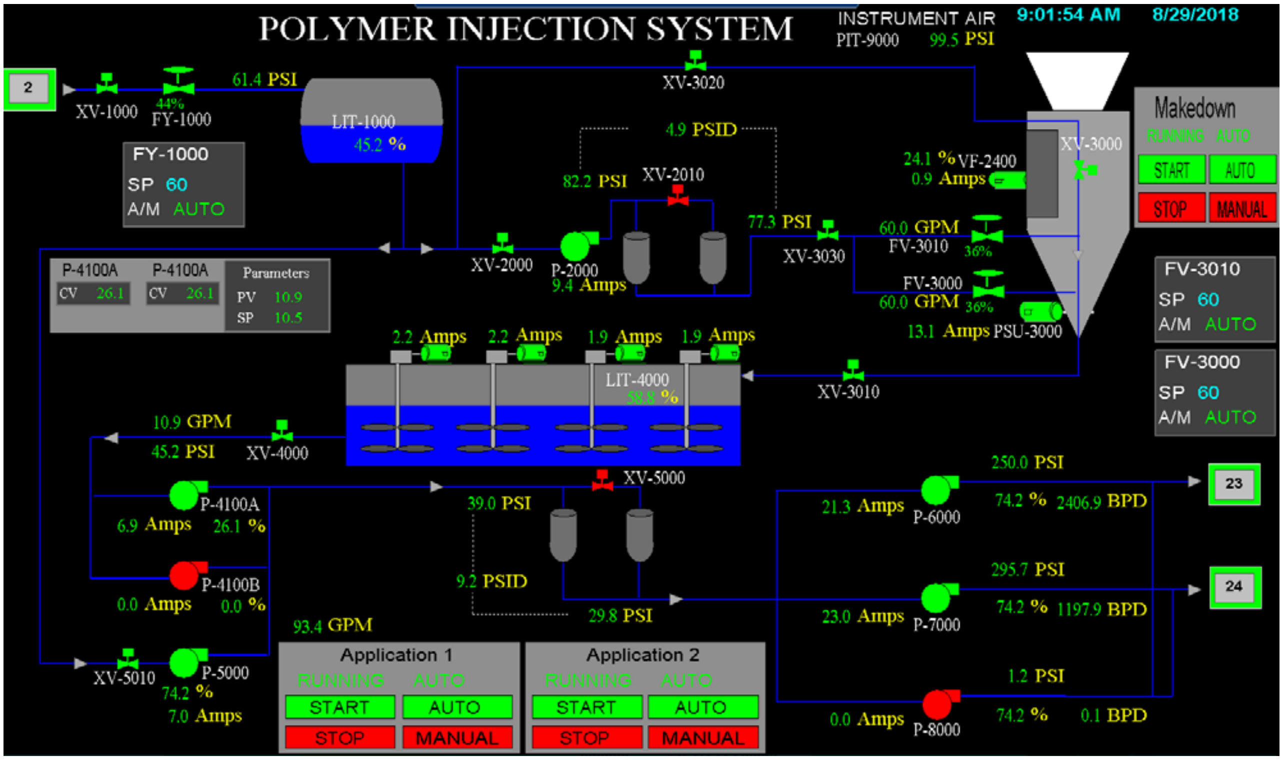

Figure 12 Polymer injection monitoring system.

Activity is ongoing.

- Task 6.0 -Analysis of Effective Ways to Treat Produced Water that Contains Polymer

Based on the conducted literature review the applied oil/water separation techniques in typical chemical EOR projects have been tabulated, and are shown in **Table 2** below. Although, some new technology is emerging to solve the separation problem, but the application is limited due to the high cost and the lack of matched facility. However, to minimize the influence on the oilfield production and current production system, the first step is to screen suitable emulsion breaker to deal with the produced fluids. The demulsification performance is evaluated through the bottle test which is a well-known method in the petroleum industry.

Table 2 Screening criteria for polymer contained produced water treatment based on literature review.

DAQING					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
45	3000-7000	11	3~9(F)	ASP	1.Three phase separator –free water knockout-electrical dehydrator

					2.Floatation –two stage filtration-back washing -sterilization
Problems				Solution	
Poor demulsification				• Change power supply • New mix demulsifier/micro-emulsion demulsifier • Optimize structure and materials of coalescence Packing material and operation conditions	
High oil content in wastewater				• New flocculants • Air-sparged hydrocyclone • PVDF membrane	
Scaling of heating furnace				Anti-scaling agents	
Foam in produce liquid				Screw pumps and defoamer	
SHENGLI					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
68	8200	12.5	45(R)/ 100-3000(F)	SP	three phase separation- settling tanks-heating-electrical dehydrator
Problems				Solution	
• Poor demulsification • High oil content in wastewater				• New flocculants/compound chemicals with both dehydration and de-oil ability • Micro-demulsifier	
KAYAMAY					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
40	7990	8.9	8.82(R)/ 52.6(F)	ASP	N
Problems				Solution	
• Poor demulsification • High oil content in wastewater				New demulsifier	
LIAOHE					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
55	3500	N	14(R)	SP	three phase separator- settling tank- electrical dehydrator
Problems				Solution	
• Poor demulsification • High oil content in wastewater				New demulsifier	
GUDAO					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
71	3900	12.5	50-150(R)/ 1475-3875(F)	ASP	1.three phase separator-two stage settling-heater-electrical dehydrator 2.two stage deoil tank- buffering tank-pressure filter
Problems				Solution	

• Poor demulsification • High oil content in wastewater				New demulsifier	
GUDONG					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
65	8207	12.5	45(R)/350 (F)	ASP	Settling tank- electrical dehydrator
Problems				Solution	
• Poor demulsification • High oil content in wastewater • Electrical breakdown				New demulsifier	
HENAN					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
50	2125	10	80-120(F)	SP	1. three phase separator- thermal-chemical settlement 2.Two stage settling- two stage filtration
Problems				Solution	
• Poor demulsification • High oil content in wastewater				• New demulsifier • New inverse demulsifier and flocculant	
DAGANG					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
53	13450	5.21	50(R)	SP	Free water remover-thermochemical dehydration-two stage settling tank
Problems				Solution	
• Poor demulsification • High oil content in wastewater				Compound chemicals with both dehydration and deoil ability	
Cambridge Minnelusa					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
55.6	N	3.5	31(F)	ASP	Free water knockout-heat dehydration- settling tank
Problems				Solution	
• Poor demulsification • High oil content in wastewater				New demulsifier	
BOHAI SZ360-1					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
65	9084	14.28	70(R)	Polymer	1.two stage settling –electrical dehydrator 2.deoil tank- two stage filtration
Problems				Solution	
Emulsification				Gemini demulsifier	

soft water shortage				Membrane	
high oil content in wastewater				• Add floatation system • New flocculants	
Pelican Lake					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
12-17	8000	1.8-2.6	1500-10000(F)	Polymer	Two phase separator- free water knockout-heat treater
Problems				Solution	
• Produced water reinjection • Oil water separation				• Diluting produced liquid • New demulsifier	
Scaling				Scale inhibitor	
Failure of fire tube				High performance demulsifier	
Oman					
Reservoir T(ºC)	Salinity (mg/L)	Reservoir P(Mpa)	Viscosity (cp)	Flooding	Treatment process
46	7404	N	40-120(F)	Polymer	Skim tank-Flotation/flocculation-filtration-absorption
Problems				Solution	
High oil content in water				• Two stage flocculation • AS replace PAC as flocculants	

Activity is ongoing.

- Task 7.0 - Feasibility of Commercial Application of the Proposed Advanced Polymer Flooding in ANS Heavy Oil Reservoirs

Activity has not yet started.

c. Opportunities for Training and Professional Development
Nothing to Report.

d. Dissemination of Results to Communities of Interest
Nothing to Report.

e. Plan for Next Quarter
Building on the current progress achieved by the research team, work planned for the next quarter will include steadily progressing toward the planned completion dates outlined in **Table 3** below.

Table 3 Summary of milestone status.

Milestones	Task No.	Planned Completion Date	Actual Completion Date	Verification Method	Comments
Project Management Plan	1a	o 9/30/2022	o Ongoing	Report	None
Data Management Plan	1b	o 8/31/2018	o 7/20/2018	Report	None
• Initial polymer screening and concentration • Quantify polymer retention	2	o 9/30/2018 o 3/31/2019	o 8/1/2018 o Initiated	Report	None
• Effect of water salinity on S_{or} • Screening of gel products for conformance control	3	o 4/30/2019 o 6/30/2019	o Initiated o Initiated	Report	None
• Pilot area model waterflooding history match • Coreflooding model history match • Updated area model for polymer flood prediction • Reservoir modeling report	4	o 12/312018 o 4/30/2019 o 5/31/2019 o 5/31/2019	o Initiated o Initiated o Not yet started o Not yet started	Report	None
• Test site selection • Equipment installation and testing • Injection profile log • Tracer tests (pre-polymer)	5	o 6/30/2018 o 7/31/2018 o 9/30/2018 o 9/30/2018	o 6/30/2018 o 8/23/2018 o 8/11/2018 o 8/3/2018	Report	None
• Initial treatment plan recommendation based upon literature survey	6	o 12/31/2018	o Initiated	Report	None

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2. PRODUCTS

Nothing to Report.

3. PARTICIPANTS & OTHER COLLABORATING ORGANIZATIONS

Nothing to Report.

4. IMPACT

Nothing to Report.

5. CHANGES/PROBLEMS

Nothing to Report.

6. SPECIAL REPORTING REQUIREMENTS

Nothing to Report.

7. BUDGETARY INFORMATION

A summary of the budgetary information for the first budget period of the project is provided in **Table 4**. This table shows the planned costs, reported costs, and the variance between the two. Reported costs is the sum of UAF’s incurred expenses and the sum of the invoices received from our project partners. The variance for this report period is large because we have not received invoices from any of our project partners as of August 31, 2018.

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Table 4 Budgetary Information for Budget Period 1.

Baseline Reporting Quarter	Budget Period 1	
	June-Aug 2018	
	Q1	Cumulative Total
Baseline Cost Plan		
Federal Share	$523,869	$523,869
Non-Federal Share	$504,049	$504,049
Total Planned	**$1,027,918**	**$1,027,918**
Actual Incurred Cost (UAF only--no other institutions have invoiced)		
Federal Share	$84,836	$84,836
Non-Federal Share	$0	$0
Total Incurred Cost	**$84,836**	**$84,836**
Variance		
Federal Share	-$439,033	-$439,033
Non-Federal Share	-$50,4049	-$50,4049
Total Variance	**-$943,083**	**-$943,083**

As of August 31, 2018, UAF has not received invoices from our project partners, hence the large variance. Please note that the PMP also has a spending plan that is based on calendar quarters.

8. PROJECT OUTCOMES

Nothing to Report.