Polymer Solution Preparation, Quality Control, and Produced Fluid Analysis at Milne Point

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Summary

This paper focuses on solution preparation and quality control activities associated with the Milne Point polymer flood on the North Slope of Alaska. This project uses 10 different polymer injection locations with a variety of skid types and configurations, which had a notable impact on polymer quality control and dissolution operations. Compared with bulk 500-kg to 750-kg polymer bags, silos greatly improved the storage capacity and increased the overall quality of the polymer solutions. Silos required less physical effort when transferring polymer. Polymer hydration skids that were made in-house by the polymer supplier were more reliable and experienced fewer polymer solution quality and startup issues than those that were outsourced. These in-house skids also used a uniform programming software that made it relatively easy to train the operators on new hydration skids. For pumping polymer mother solution, triplex pumps provided the best runtime and were most maintenance-friendly, compared with diaphragm or triple screw pumps. Because of the soluble iron present in the polymer makeup water, nitrogen blanketing was preferred to minimize corrosion and oxidative degradation. Inline static mixers were ineffective in mixing mother solution with dilution water when the mixing occurred close to the wellhead. Mixing the two streams too close to the wellhead led to substantial variations in wellhead viscosity measurements. Dedicating individual pumps for injection into a given well provided desirable flexibility in controlling rates and concentrations of polymer for the well. Monitoring produced salinity and polymer concentration provided useful insights about improved sweep and polymer retention associated with the polymer flood. The observed field behavior was consistent with laboratory studies, indicating a "tailing" phenomenon associated with polymer retention at Milne Point.

Introduction

The Milne Point field is a 71,000-acre field on the Alaskan North Slope that produced 414 million barrels of oil since production first started in 1985. The highest production rate (60,000 BOPD) was reached in 1995, and a production minimum (17,000 BOPD) was experienced in 2012. As of 2024, production averages 38,000 BOPD. The very successful Milne Point polymer flood targets three Schrader Bluff sandstones—the Nb, Oa, and Oba sands. Porosity averages 30–32% while permeability averages 1,200 md in the Nb sand and 120–150 md in the Oa and Oba sands. Net reservoir thickness averages 14 ft in the Nb sand, 32 ft in the Oa sand, and 26 ft in the Oba sand. Reservoir temperature ranges from 70°F to 90°F, and depth is between 3,600 ft and 4,100 ft below sea level. Development of the Schrader Bluff sands began in 1991 using vertical wells drilled on 160-acre spacing. Waterflooding began in some areas of the field around 1992 to 1993. Drilling of horizontal wells began in the late 1990s. Up to the end of 2023, 12 drilling locations (gravel pads) existed, with a 13th pad (the R-Pad) added during 2024. Eight of the existing pads inject polymer, and polymer injection is planned for the new R-Pad. Polymer injection began in the J- and L-Pads in late 2018, with polymer injection in other pads commencing at various times since 2018 **(Table 1)**.

In one pattern (the J-Pad), this project has seen produced water cuts drop from ~70% during waterflooding before the project to less than 5% during polymer injection. In another pattern (the L-Pad), more than 0.23 pore volumes of polymer solution were injected to displace 850 cp oil before significant produced water and polymer breakthrough was detected. Consistent with other projects where polymer flooding is applied to recover viscous oils, oil recovery benefits from early implementation of the polymer project (Delamaide 2021; Edwards et al. 2022). As discussed in Dean et al. (2024), polymer injectivity was not generally a problem at Milne Point (either from the facility or reservoir view points), in spite of the high oil viscosities and polymer viscosities required to achieve a polymer/oil mobility ratio near one. For cases where no waterflood occurred before polymer flooding, polymer injectivity generally remained stable throughout polymer injection. This observation is consistent with expectations (Wang et al. 2022b) as the mobility of the injected fluid was basically the same as that of the displaced oil. For cases where waterflooding occurred and significant water breakthrough was noted before polymer injection started, polymer injectivities generally decreased by roughly 50% during polymer injection (Dean et al. 2024). This result is not surprising (at least qualitatively) because viscous polymers gradually displaced low-viscosity water from water fingers that led between injectors and producers.

Many aspects of this project are documented in Dandekar et al. (2019, 2021a, 2021b, 2023), Ning et al. (2019, 2020), Wang et al. (2020, 2021, 2022a, 2022b, 2023), Chang et al. (2020, 2022), Dhaliwal et al. (2021, 2022), Zhao et al. (2021), Edwards et al. (2022), Keith et al. (2022a, 2022b), Seright and Wang (2022, 2023a, 2023b), Aitkulov et al. (2024), and Dean et al. (2024). Please see Aitkulov et al. (2024) and Dean et al. (2024) for the most updated information about overall field performance of the Milne Point polymer floods and injectivity observations.

A number of previous publications examined particular aspects of surface equipment associated with preparation and injection of polymer solutions, including the contrast between using powder vs. emulsion polymers (Morel et al. 2012; Raney et al. 2012; Rivas and Gaither 2013; Jouenne et al. 2016; Dwarakanath et al. 2016), water treatment (Dwyer and Delamaide 2015), use of skids vs. centralized

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Pad	Polymer Start Year	Sands	Injectors/ Producers	Avg. Well Length (ft)	Well Direction	Well Spacing (ft)	Oil Viscosity (cp)
J	2018	Nb	3/3	4,500	E-W	1,100	350
L	2018	Nb	5/5	7,000	N-S	800	850
F	2020	Oa/Kuparuk	3/2	6,500	NW-SE	800	110
M	2020–2024	Nb/Oa/Oba	13/14	7,800/10,000/ 11,260	NW-SE/N-S	900/800/400	560/85/17
I1	2020	Nb	3/3	8,250	NW-SE	1,100	175
I2	2021	Oa/Oba	5/4	11,000/7,400	N-S	800	25/13
E	2021–2024	Nb/Oa/Oba	3/3	7,700/5,800	NW-SE/N-S	1,800/1,000	45/40
S	2022	Nb	2/3	8,400	NW-SE	1,400	45
B	2023	Oa	3/4	6,600	NW-SE	800	85
R	2024	Oa	20/20	10,000	NW-SE	400	85

Table 1—Polymer injection locations (pads).

Pad	Sands	Start	Skid Design	Polymer Hydration	N_2 Blanket?	Mother Solution Polymer Pump	Well House Pump	Dilution Water Added At	Individual Pump Per Well
J	Nb	2018	In-house A	Slicer A	Yes	Triplex	None	Skid	Yes
L	Nb	2018	In-house A	Slicer A	Yes	Triplex	None	Skid	Mixed
F	Oa/Kuparuk	2020	In-house A	Slicer A	Yes	Triplex/ Metering A	Triplex	Header	Yes
M	Nb/Oa/Oba	2020	Outsourced B	Shear A	No	Metering B	None	Wellhouse	No
I1	Nb	2020	In-house A	Slicer A	Yes	Metering A	Diaphragm /Triplex	Wellhouse	Yes
I2	Oa, Oba	2021	Outsourced C	Shear B	Yes	Metering B	Diaphragm /Triplex	Wellhouse	Yes
E	Nb/Oa/Oba	2021	Outsourced D	Shear C	No	Triplex	None	Header	No
S	Nb	2022	In-house A	Slicer A	Yes	Metering A	Diaphragm	Wellhouse	Yes
B	Oa	2023	In-house A	Slicer B	Yes	Metering A	Diaphragm	Wellhouse	Yes
R	Oa	2024	In-house A	Slicer A	Yes	Triplex	None	Header	No

Table 2—Comparison of polymer skids at Milne Point.

facilities (Juri et al. 2022; Gathier et al. 2022), pump and mixing inefficiencies (Wang et al. 2004), mechanical degradation of polymer (Wang et al. 2009; Jouenne et al. 2015, 2017; Husveg et al. 2020; Sagyndikov et al. 2022), and solution mixing and quality (Lüftenegger et al. 2015; Mehta et al. 2016; Kumar et al. 2016). While the above papers typically focus on individual facility issues associated with polymer preparation, this paper is intended to provide a unique overview of polymer surface facilities for an arctic onshore application. This information should be of particular value to those considering the implementation of an onshore polymer flood.

This paper focuses on solution preparation and quality control activities associated with the Milne Point polymer flood on the North Slope of Alaska. The full-field project injects partially hydrolyzed polyacrylamide (HPAM) or acrylamide-acrylate copolymer polymer solutions (with a targeted polymer/oil mobility ratio of one) into parallel horizontal wells throughout the 71,000-acre field. Multiple fault blocks and varied oil viscosities (10–1,300 cp) necessitated the use of localized polymer preparation and injection skids located through the field. This paper discusses the challenges and successes associated with polymer preparation and injection in an arctic environment. This project uses 10 different polymer injection locations **(Table 2)**, with a variety of skid types and configurations. The different skid configurations had a notable impact on polymer quality control and dissolution operations—which will be discussed. The first column in **Table 2** lists the 10 different polymer injection locations (i.e., pads), while the second column lists the Schrader Bluff sand formation that was polymer flooded. (Note that the F-Pad injected into the Kuparuk formation, as well as the Schrader Bluff Oa sand.) The third column lists the year that polymer injection started in a given pad. Subsequent columns list additional characteristics that will be discussed in the paper.

Topics covered in this paper include an overview of the various polymer skids, along with detailed discussion of various equipment and parts of the flow stream (water filtration, polymer delivery and storage, polymer hydration equipment, pumps, final polymer filtration, and assessing polymer dissolution). At the end, we describe efforts to monitor produced salinity and polymer concentration, along with implications for sweep efficiency and polymer retention in the Milne Point field. We hope the findings will be of high value to other polymer floods.

Polymer-Dissolution Skid Varieties

Since 2018, two major polymer suppliers and four different manufacturers of polymer skids have been used, each with their own programming and hydration technologies, listed in **Table 2**. Only one of the two polymer suppliers manufactured their own polymer hydration

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(dissolution) skids. The second polymer supplier contracted several different companies to manufacture their polymer dissolution skids. Skids that were made in-house by the polymer supplier were more reliable and experienced fewer polymer solution quality and startup issues. These skids also used uniform programming software that made it relatively easy to train the operators on new hydration skids. Uniformity of skid source also facilitated consistency with equipment troubleshooting and for critical spare parts.

Outsourced polymer skids had more startup, programming, and solution quality issues. Different skids inherently experienced different issues. Outsourced skids all used different, nonuniform operational programming, which steepened learning and troubleshooting curves for operators. Outsourced skids required excessive stocking of spare parts for the different units. They also increased downtime because breakdowns required the polymer supplier to request replacement parts from the outsource, accentuating delays.

J-Pad and L-Pad Polymer Facilities (2018). For the initial polymer systems in J- and L-Pads, Hilcorp implemented a predesigned unit from a polymer vendor. This unit takes high-pressure water, reduces it to atmospheric pressure using a water let-down tank, combines it with polymer (supplied via silo), and uses a dedicated adjustable-rate triplex pump and flowline per well to inject the solution as shown in **Figs. 1 and 2**. A triplex pump is a reciprocating pump design that utilizes three separate rods to drive three plungers or pistons, which push fluid into or out of one of three cylinders. The three drive rods connect to a central drive shaft that is turned by an electric motor. Pump rate can be varied by adjusting the motor speed.

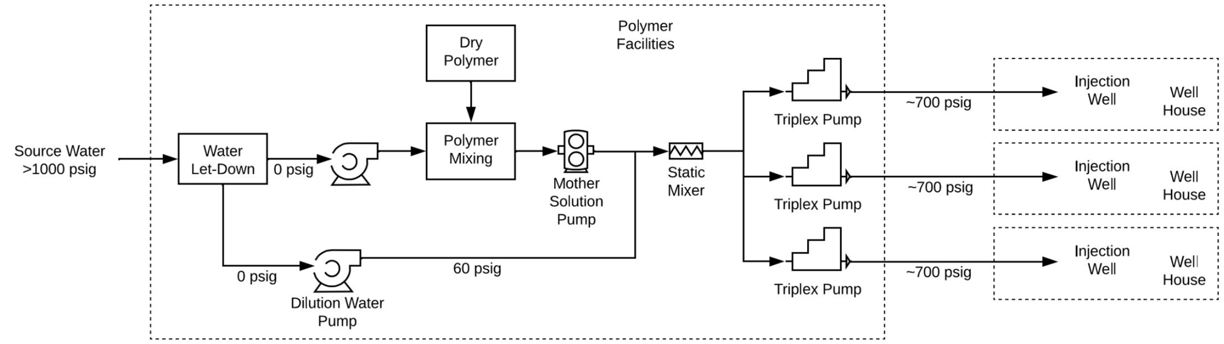

Fig. 1—J-/L-Pad facility configuration.

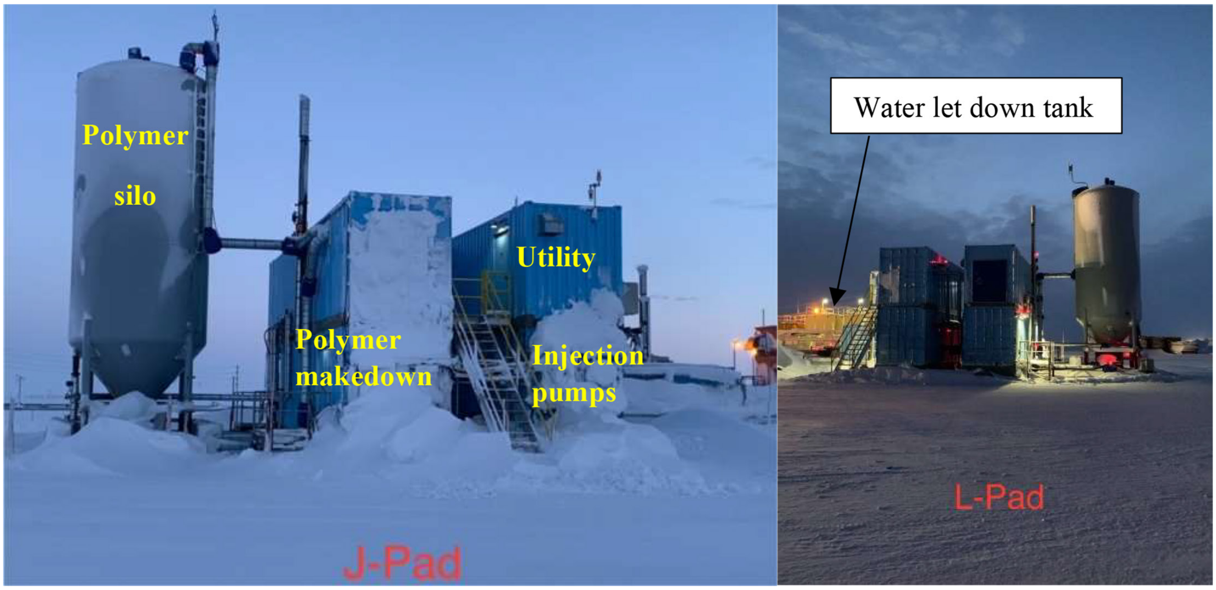

Fig. 2—Exterior views of the J- and L-Pad facilities.

One advantage of this setup is that a central facility contains all the polymer equipment. Another is that it is relatively plug and play—this same design can be used in almost any field and requires little input or expertise from the operator of the field. Because all equipment is contained within one facility, that facility must be designed with all future polymer injectors in mind, either requiring more upfront capital or future expansions. The water pump, metering pump, and maturation tank must be upsized during expansion after the pilot injection period. It is more advantageous to have a skid designed for larger volumes in case the initial pilot is successful and an expansion is planned.

The L-Pad skid had fewer issues compared with the J-Pad skid. An initial problem with the J-Pad skid (during the first year of the polymer flood) was that mother solution tank veers (baffles) were installed incorrectly. The mother solution tank (or polymer mixing tank, shown in **Fig. 3** for the F-Pad) was a rectangular tank that accepted the polymer suspension immediately after the polymer hydration units (i.e., either polymer slicing or shear-pump units). This tank had multiple compartments that were each separated by a tank veer or baffle. Each compartment also had an agitator blade that continuously stirred the polymer suspension/solution. For the incorrect veer placement,

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Fig. 3—Exterior and interior views of the F-Pad facility.

openings between compartments were all located at the top of the tank. This veer placement allowed nonhydrated polymer to short-circuit through the tank—flowing directly across the top portion of the tank. This situation allowed the formation of substantial "fisheyes" and large chunks of undissolved polymer gels to flow through the system and be injected. The problem was corrected by alternating the locations of the openings (top in one compartment and then bottom in the next) so that polymer suspension/solution was forced to flow through the agitator blade and the entire compartment. In addition, we increased agitator blade size for better mixing. Residence time in the tank was also increased by lowering the position where the line from the slicing unit entered the mother solution tank. (This helped because the immaturely mixed polymer tended to rise in the tank.) Currently, after initial troubleshooting, the J-Pad skid is one of our most reliable skids. The triplex pumps used for the polymer injection are very reliable and do not require much maintenance.

In general, since the first year of operation, polymer mother solutions from the various pad hydration facilities have been smooth, well-dissolved, and free of fisheyes—so long as the hydration equipment at a given pad did not experience a mechanical failure and the system was not contaminated by diesel oil. Mention should be made that diesel oil is commonly used to freeze-protect certain parts of the flow system (e.g., the water-pressure let-down tank) during temporary shutdowns. If that oil is not thoroughly flushed from the flow stream before restarting polymer injection, it accentuates the formation of fisheyes and gels. This problem can persist for weeks if the cleanout is not sufficiently thorough before startup.

F-Pad Polymer Facilities (2020). Concerning the F-Pad, the main difference from the J- and L-Pads is that the F-Pad facility has a much larger working space. While the J- and L-Pad facilities are housed in conex boxes (i.e., shipping containers shown in **Fig. 2**), most F-Pad equipment (except the silo) is housed in one spacious module **(Fig. 3)**. The slicing unit is located directly under the silo, which is connected to the main module (through the door shown at the rear of the room in the right photo of **Fig. 3**). Experience at the J- and L-Pads taught Hilcorp to use larger maturation tanks. Use of larger maturation tanks resulted in more consistent hydration and reaching target viscosities.

M-Pad Polymer Facility (2020). At the M-Pad (also called the Moose Pad), the desired surface injection pressure and polymer concentration were the same for every well (except for one completed in the Schrader Bluff Nb sand). This allowed the addition of polymer at minimal cost by simply injecting polymer into the common header that was already present. A polymer hydration skid was added, and an existing tank was repurposed as a water let-down tank **(Fig. 4)**. This system is by far the most capital efficient, but it has a limited use. It can only be used when all wells that are fed from the header have the same desired concentration and injection pressure (because choking back the wells will shear, degrade the polymer, and reduce viscosity).

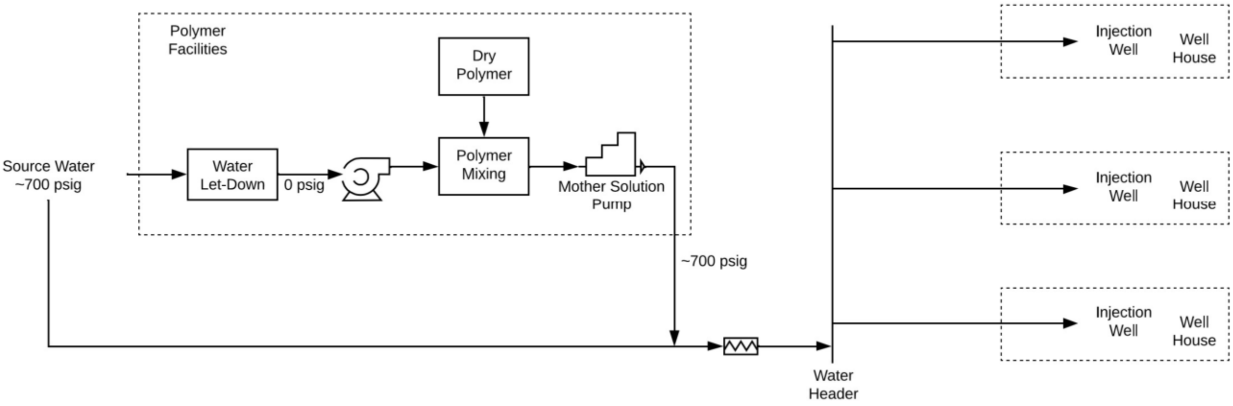

Fig. 4—M-Pad facility configuration.

The M-Pad skid **(Fig. 5)** is housed in three conex boxes attached to each other, where one conex box is devoted as an electrical module (MCC) and the other two were used for hydration. Also, the water let-down tank is outside behind the main skid structure. It is close in design to the F-Pad skid, but it has different internal equipment since the polymer vendor is different. It is very unreliable because the

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Fig. 5—Photos of the M-Pad facility.

positive displacement pump's springs and valves need constant replacement due to washouts/erosion of parts. The hydration-system design was overly complex due to many moving parts.

I-Pad (2020 to 2021) and S-Pad (2022) Polymer Facilities. The I-Pad injectors were part of a redevelopment effort, adding wells to a relatively mature waterflood. The injection pressure at the target rate varies substantially between the wells. As a result, a single final solution header was not feasible. Hilcorp instead chose to add a concentrated polymer solution header and added small injection pumps at each well (illustrated schematically on the right side of **Fig. 6**).

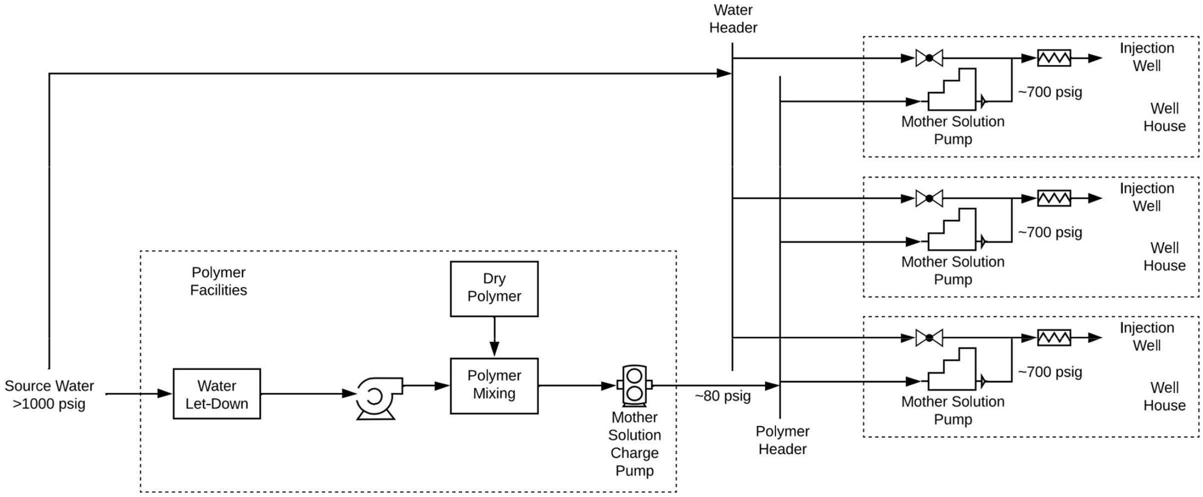

Fig. 6—I-Pad facility configuration.

One advantage of this approach is scalability. After the initial header is added, each new injector only requires a short lateral pipe run and a pump. Because every injector is equipped with a wellhouse, the small injection pumps are simply added inside these existing structures. These pumps only need to handle the concentrated mother solution, so they process ~88% less fluid than the triplex pumps at the J- or L-Pads (the earliest configurations). A disadvantage of this configuration resulted from the short distance between the wellhead and the point where the mother solution was added to the dilution water. In spite of the presence of a static mixer, the dilution water and mother solution were never mixed well. Consequently, viscosities of wellhead samples were quite erratic. (A static mixer is typically a short section of pipe that houses a convoluted flow path. For example, one type of static mixer simply consists of a large chain link set that is welded inside of the pipe.)

The I-Pad Skid 1 design was the same as that for the J- and L-Pads, except the dilution of polymer mother solution occurred inside individual wellhouses for each injector. The reliability of the I-Pad Skid 1 was similar to that for the J-, L-, and F-Pads. The S-Pad skid was identical to the I-Pad Skid 1.

The I-Pad Skid 2 was schematically similar to I-Pad Skid 1 but used a different polymer vendor and equipment. The shear pump used here was very unreliable because of poor-quality stators and rotors that failed frequently. The software for this skid was also too complex and not operator friendly.

E-Pad Polymer Facilities (2021). As part of our efforts to identify the most cost-effective equipment and procedures, nitrogen blanketing was not used at the E-Pad (because nitrogen blanketing added cost). Unfortunately, the E-Pad skid was subsequently found to be the most unreliable and prone to mechanical breakdowns, corrosion, and inadequate polymer hydration. The maturation tank, internals, and water

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Fig. 7—Corrosion due to lack of nitrogen blanket at the E-Pad.

let-down tank were all housed in one very cramped conex box. It required more operator supervision to keep it running. Current water filters are undersized to filter the high iron content in the water, compared with other pads. Other skids have larger water-filtering surfaces, so they plug much less often. We observed direct polymer buildup on the shear pump because the hydration unit (a funnel design) was open to the atmosphere (i.e., no nitrogen blanket). In contrast to other skids, the E-Pad skid did not have any nitrogen blanket over the maturation tank. **Fig. 7** shows examples of the corrosion resulting from using black iron and no nitrogen blanket. Ironically, even though significant corrosion was observed, the final solution injection viscosity met the target level. Nevertheless, the resulting particulates (iron oxide, etc.) accentuate plugging/injectivity problems in the injection wells.

B-Pad Polymer Facilities. B-Pad is very similar to the I-Pad Skid 1 and the S-Pad skid. The main difference is a smaller shear pump and the silo is located immediately above the conex box that houses the hydration unit. Due to the smaller shear pump, the throughput of the system is reduced, but it is significantly more cost-effective.

R-Pad Polymer Facilities (2024). The next polymer facility to start up will be located at a new well pad (R-pad). This skid is most similar to the J- and L-Pad skids, with the main difference being the use of a triplex pump to charge the mother solution header and reduced pressure at each well. The mother solution header will operate at ~100 psig above the expected injection pressure, and coil chokes (as in Weiss and Baldwin 1985) will be used to achieve the pressure reduction and rate control in the wellhouses. Fundamentally, the coil chokes replace the function of the wellhouse pumps used at other pads. Below is the process flow diagram for this configuration **(Fig. 8)**. The main reason for this change is to reduce the capital and maintenance costs associated with the wellhouse injection systems. Due to an increase in material and labor costs, the wellhouse pump systems increased significantly in price. Additionally, these positive displacement pumps require routine maintenance, further straining resources in an already busy field. The coil chokes consist of long lengths of small diameter tubing, with valves to force fluid to take a longer path or shortcut sections of tubing to achieve the desired rate. Because these are being used for mother solution only, the size of the coil chokes is reduced considerably and can be installed in the wellhouses in place of the wellhouse pumps in use at I-, S-, and B-Pads. As these devices are brought online, the polymer will be

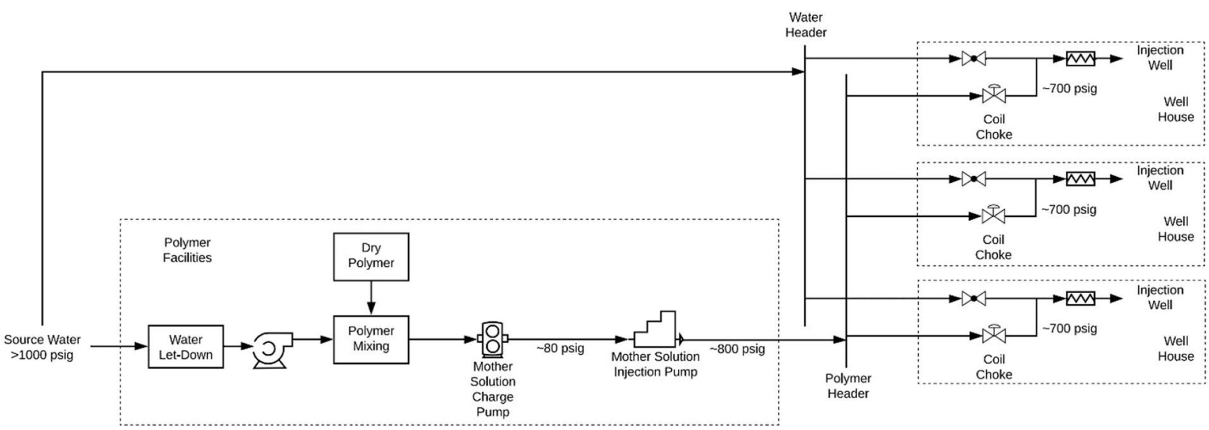

Fig. 8—R-Pad facility configuration.

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Fig. 9—Magnetic bag filter.

Fig. 10—Cartridge filters (individually new on the right; installed in the housing on the left).

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sampled before and after the coil choke to monitor for any mechanical degradation. Additionally, the configuration will be evaluated for flow control capability.

Water Filtration

Water for the polymer floods was usually sourced from the Prince Creek formation, which had a salinity of about 2,500 ppm total dissolved solids (TDS), typically with less than 100-ppm divalent cations. For the 10 different polymer makeup locations, high-pressure (~1,000 psi) water was supplied on site, but the pressure was reduced to atmospheric pressure at each polymer makeup facility. Water filtration was essential before entry into the polymer dissolution skid to minimize any iron or other insoluble sediments. We found that prefiltration using a 5-µm magnetic bag filter **(Fig. 9)** was effective for removing iron particulates from the makeup water. Skids with black-iron piping experienced much more iron buildup, corrosion, and oxidative polymer degradation than skids without black-iron piping. After the 5-µm bag filter, 1-µm cartridge filters **(Fig. 10)** further captured debris and hydrocarbons, which also had a substantial effect on quality-control filter-ratio tests of the prepared polymer solutions.

Polymer Delivery and Storage

Polymer is shipped to the field using a combination of barge, rail, and trucking. Ultimately, it arrives at the field site and is currently offloaded from a pneumatic displacement truck into a storage silo **(Fig. 5)**. **Fig. 11** shows the polymer makeup and injection skid for the first polymer application (i.e., in the J-Pad, begun in 2018). The polymer mixing and pumping skids were custom designed and manufactured and involved five modules: the pressure let-down module, the injection pump module, the polymer make-down module, the hopper, and the utility module. The pressure (or water) let-down module reduces the supplied water pressure from 700–1,000 psi down to atmospheric pressure. The injection pump module housed the injection pump. The polymer make-down (dissolution) module contained a tank where polymer was allowed time to dissolve after first being exposed to water in the polymer slicer or shear unit. The hopper stored the dry polymer powder. The utility unit housed electrical and control components and a laboratory workspace.

Fig. 11—Polymer makeup and injection skid for the J-Pad (Ning et al. 2019).

For the early applications at Milne Point (J-Pad and L-Pad), polymer powder was transported and stored in bulk bags, each containing either 500 kg or 750 kg of HPAM. The bulk bags were loaded onto the hopper with a forklift, and the polymer was fed into the polymer make-down unit below, where it was mixed with water to make a mother solution (typically containing 5,000–12,000 ppm HPAM). After 100 minutes of hydration time in the tank, the mother solution was slipstreamed into the main water supply that fed into three triplex positive displacement injection pumps in the pumping unit, one for each of the two injection wells plus a spare. Later (based on experience and recommendations of the polymer suppliers), silos **(Figs. 2 through 5)** were found to greatly improve the storage capacity and increase the overall quality of polymer hydration in the system. Silos required less physical effort when transferring polymer. Also, use of the bulk bags made it difficult to keep contaminants and moisture out of the polymer during transportation to the field. During offloading of the polymer transport trailer, polymer was screened **(Fig. 12)** before it entered the silo. Debris or contaminants in the polymer were trapped in the screen, thus preventing entry into the polymer hydration system and minimizing damage to polymer slicing unit staters, rotors, and pumps.

Polymer Hydration Equipment

Over the years at Milne Point, four different manufacturer skids were operated with five diverse types of hydration technologies. Details on the operation of these diverse hydration units can sometimes be found in the open literature (Weiss and Baldwin 1985; Morel et al. 2012; Jouenne et al. 2016; Gathier et al. 2022) or from brochures provided by the polymer suppliers. However, often these details are proprietary and not disclosed. Our focus here will be on the equipment that provided the best run time and maintenance performance. Each

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Fig. 12—Screen used during polymer transfer into a storage silo.

piece of equipment had its own unique challenges for the arctic conditions in a remote location. The polymer slicing unit shown in **Fig. 13** was one of the first polymer slicing units that we put into service. (A polymer slicing unit cuts polymer particles extremely finely so that water contact with the polymer grains is maximized, thus accelerating polymer dissolution.) With preemptive maintenance, this has been the most durable, robust rotor and stator and slicing unit. Runtimes of 96–99% were a substantial component of the success provided by these polymer slicing units.

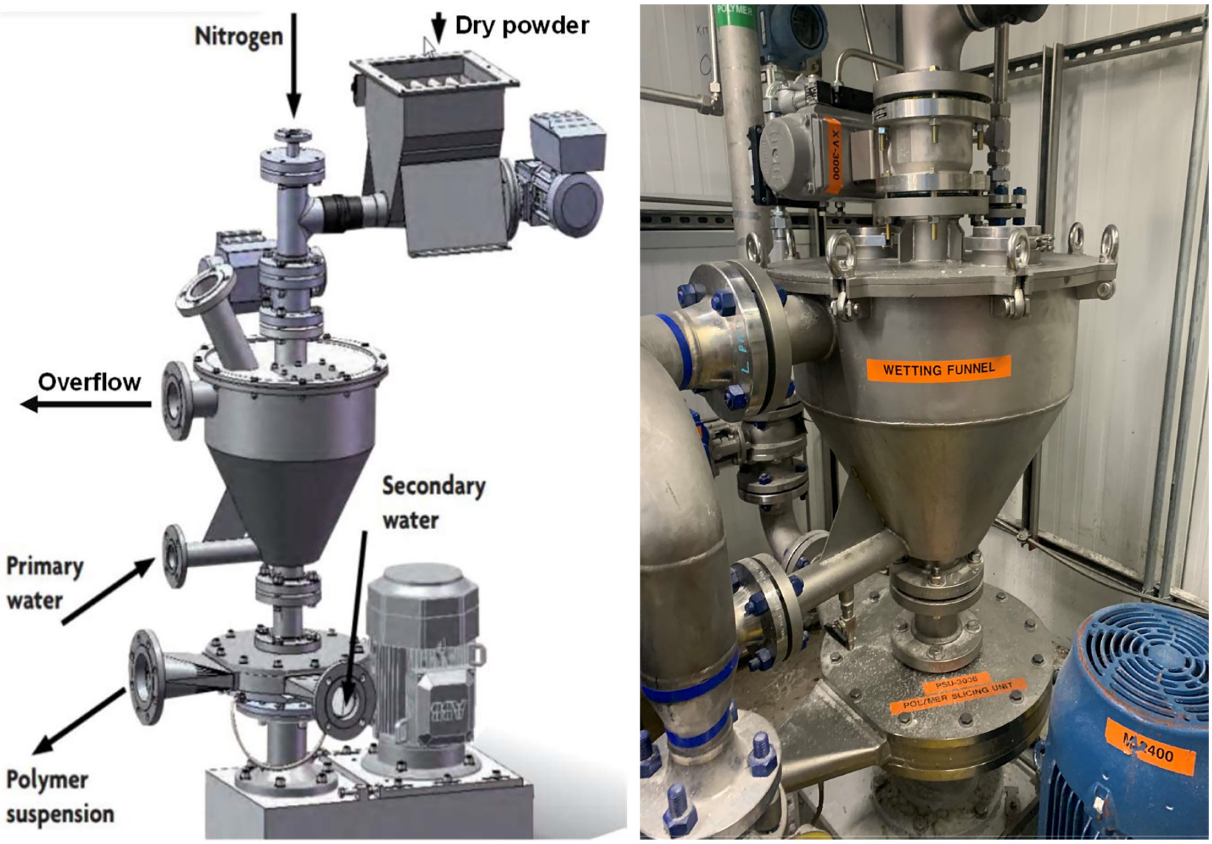

Fig. 13—Effective polymer slicing unit for polymer dissolution (schematic on the left; actual on the right).

An alternative shear pump was utilized for about 12 months but exhibited inferior reliability and runtime. (A shear pump forces wetted polymer grains through a rotor/stator combination to enhance polymer dissolution. The rotor rotates at very high speeds.) This unit was very maintenance-intensive and prone to packing-off due to the tight tolerance between shear teeth in the stator. This shear pump was replaced by a third, different shear-pump company, which was an improvement due to the larger tolerance between the teeth in the stator. The third shear pump still must be rebuilt every 3 months because of failures of the low-quality stator and rotor. **Fig. 14** shows that the

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Fig. 14—Stators and rotors of alternative shear pumps (right vs. left show two separate cases).

weak, thin metal blades (that spin at 6,400 rev/min) used in these pieces commonly experienced failures caused by debris or inconsistent polymer powder feed. This shear pump also exhibited excessive cavitation, causing critical O-rings to wash out.

Polymer manufacturers either built their polymer-dissolution equipment in house or outsourced to a different company. An advantage from a polymer supplier making their own skids was exceptional assistance and readily available replacement equipment. When the hydration skids were outsourced to a third party, delays commonly occurred when replacement parts were needed.

Pumps

Several different types of polymer injection pumps have been used during the Milne Point polymer projects, including triplex, diaphragm, and triple screw pumps. We found that triplex pumps provided the best runtime and were the most maintenance-friendly. The diaphragm pumps were effective and useful, but repairs can be costly and time-consuming. For our applications, the triple screw pumps experienced multiple failures and did not meet our desired runtimes. Centrifugal pumps cannot be used because they mechanically degrade the HPAM.

Although this paper is focused primarily on the injection side, a few comments will be made about production pumps. Production pumps used at Milne Point have primarily been electric submersible pumps (ESPs). Jet pumps have been used in some cases. These have locations/parts that can get hot enough to hydrolyze and precipitate HPAM to form an intractable gel scale (Mittal et al. 2018; Agrawal et al. 2019; Zagitov et al. 2020; Dandekar et al. 2021a; Seright et al. 2021; Prasad et al. 2022). For cases where desired production rates are not high, this problem can be mitigated by using cooler pumps—in particular, progressive cavity pumps and sucker-rod pumps. Another advantage of progressive cavity and sucker-rod pumps is that they cause minimal mechanical degradation to HPAM polymers, whereas jet pumps and ESPs can substantially degrade HPAM (Manichand et al. 2013; Hoy et al. 2020; Shankar et al. 2022). Minimizing polymer degradation allows the opportunity to (1) assess whether the polymer has propagated through the formation intact and (2) allow the possibility of recycling the polymer in the polymer flood. Unfortunately, the production rates at Milne Point have usually been too great for progressive cavity pumps and rod pumps to be viable. Because of frequent failures, one production ESP in the J-Pad was switched to a jet pump. However, use of the jet pump introduced substantial emulsification of the produced fluids and introduced uncertainty about produced water cuts. Consequently, the jet pump was replaced with an ESP.

Polymer Filtration of Prepared Mother Solution and Diluted Polymer Solution

Filters used for final filtration (i.e., before dilution or injection) of the polymer solution vary depending on the polymer concentration and molecular weight. For 1,200-ppm moderate-molecular-weight HPAM (e.g., Flopaam 3630 S™), we used a 25–50-µm bag filter. To filter mother solution (e.g., 5,000-ppm polymer), depending on polymer molecular weight, a 100–200-µm bag filter was preferred. Cardinal and Pall filters exhibited desirable performance, while cheaper filters were not satisfactory. Filter sizes were chosen based on previous experience (of observed pressure-drop and plugging behavior) from both Hilcorp and the polymer supplier.

Assessing Polymer Dissolution

Undissolved polymer has been problematic for some field projects. Polymer gel observed during well-cleanout or backproduction of injectors probably resulted because undissolved polymer was injected at some point. Undissolved polymer leads to insufficient viscosity, wastes money, and creates unnecessary injectivity losses or fracture extension. Filter-ratio tests have been strongly advocated to monitor solution quality (Dean et al. 2022) and are used for quality control at Milne Point. Samples of mother solution were typically collected and diluted to the anticipated injection concentration and then performed using the method described in Dean et al. (2022). Filter-ratio tests of these polymer solutions generally indicated acceptable polymer dissolution. However, over-reliance on filter-ratio tests alone can cause operators to overlook important dissolution problems (Dandekar et al. 2021a, 2021b; Edwards et al. 2022) because they only sample an extremely small fraction of the fluid volume injected and because they have no convincing quantitative relation to polymer injectivity (Seright et al. 2009). Filter-ratio tests should be complemented with wellhead low-shear-rate (e.g., 7.3 s^{-1}) viscosity measurements that are consistent (i.e., small variations around the target viscosity) and lack of plugging of facility filters (e.g., sock filters) that all injected polymers must pass through (Edwards et al. 2022; Prasad et al. 2022).

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As mentioned in the section "J-Pad and L-Pad Polymer Facilities," polymer mother solutions from the various pad hydration facilities have generally been smooth, well-dissolved, and free of fisheyes—so long as the hydration equipment at a given pad did not experience a mechanical failure or freeze-protect oil was properly flushed from the flow stream. Filter-ratio tests were performed on 300 mL of sample collected at the wellhead. Viscosity measurements were also made on wellhead samples.

Wellhead samples for measurement of viscosities and polymer concentrations were collected using the standard sample-bomb method, as described in *API RP 63* (1990) and Manichand et al. (2013). Nevertheless, collected wellhead samples were sometimes significantly less homogeneous than desired. This resulted from the wellhead sample point being located within a few feet of the point where mother solution teed into the brine-dilution line. Although an inline mixer was located between the tee and the sample point, it was not sufficiently effective in homogenizing the fluid. This observation is consistent with Wang et al. (2004), who also noted that inline or "static" mixers were ineffective in blending polymer mother solution with dilution water. As a consequence, erratic fluctuations in measured polymer concentration and wellhead solution viscosity were sometimes noted. For example, the blue circles in **Fig. 15** plot polymer concentrations for samples collected before injection into the J-Pad. Also, note the considerable scatter/deviation from the target viscosity (solid green curve). Thus, the wellhead polymer concentration and viscosities were sometimes compromised. Nevertheless, transit through 3,000 + feet of piping resulted in well-mixed polymer solutions before the polymer entered the formation.

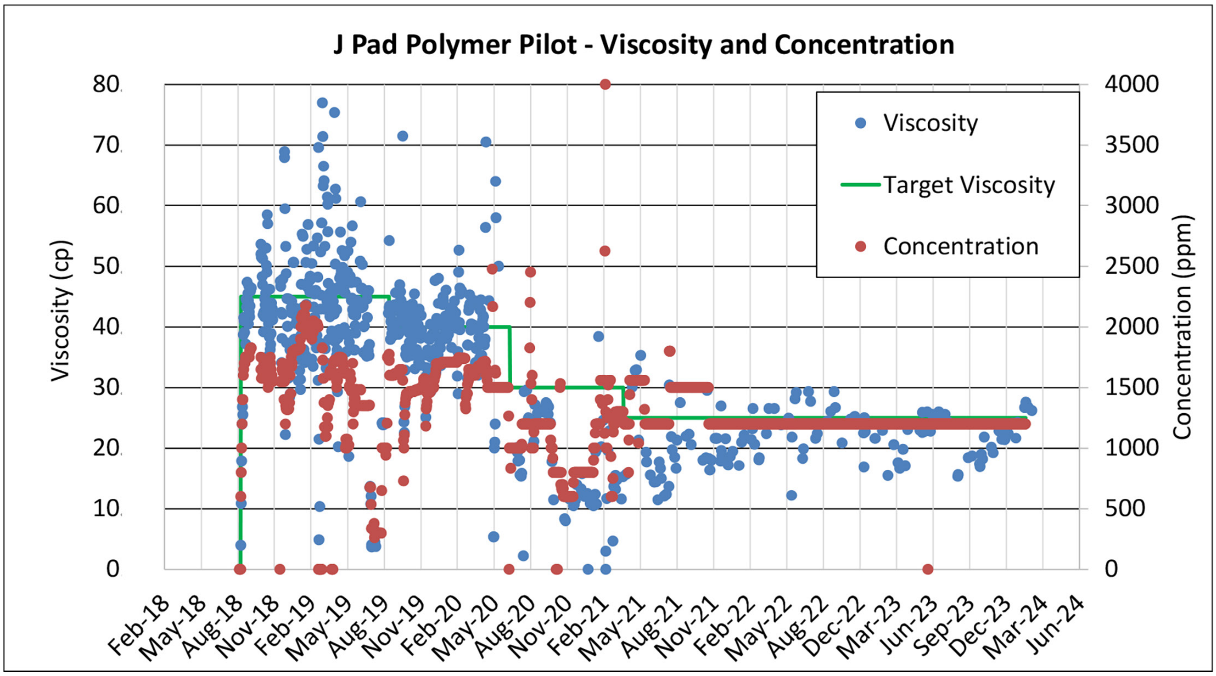

Fig. 15—Wellhead viscosity and concentration vs. time for the J-Pad.

Concerning **Fig. 15**, note that variations in viscosity and polymer concentration were more severe before 2021 than after 2021. In large part, the improvement after 2021 was due to improved oversight of the operation (e.g., more thorough flushing of diesel oil from the flow stream after freeze-protect procedures) and attention to detail during the testing.

Wellhead-sample dissolved oxygen levels were routinely measured to be less than 20 ppb for the pads and skids where nitrogen blanketing was used.

On site, polymer concentration was monitored using the bleach method (*API RP 63* 1990). Typically, 1 L of mother solution was collected for this test. (Viscosities were also routinely measured on the mother solution.) This polymer-concentration-detection method is based on the reaction of polyacrylamides with sodium hypochlorite and the resultant formation of an insoluble chloramide reaction product. The turbidities of the resulting samples were measured with spectrophotometry and concentrations were determined by comparisons with standards. Because the measurement was based on turbidity and spectrophotometry, the final sample for analysis must be free of color and contain no insoluble matter. This is a useful method, but it can be very time-consuming. The red circles in **Fig. 15** show measured polymer concentrations. The scatter of data points in this plot also reflects the mixing and diesel contamination issues mentioned in the previous paragraphs. As will be mentioned in a later section, samples produced from production wells were sent to New Mexico, USA, and analyzed for polymer concentration (and cation content) using more accurate methods (Wang et al. 2020; Seright and Wang 2022, 2023a). For injected polymer solutions, the on-site bleach method was used because it quickly provided polymer concentrations that were needed immediately, in case operational adjustments were needed. In contrast, measurement of polymer in the produced fluid was less time-critical; hence, the luxury of sending the samples to New Mexico for analysis. Incidentally, the polymer detection method used at New Mexico (nitrogen chemiluminescence) does not depend on the level of degradation experienced by the HPAM during collection or transit.

Monitoring Produced Salinity and Polymer Concentration

Useful information about polymer retention and sweep improvement can be gleaned by monitoring the salinity and polymer concentration produced from wells offsetting polymer injectors. Manichand and Seright (2014) demonstrated a procedure where the difference in arrival times for a salinity tracer vs. polymer allowed an in-situ estimate of polymer retention. We attempted a similar procedure for the Milne Point polymer floods. The salinity of produced water was monitored by collecting samples and performing analyses for dissolved sodium, potassium, magnesium, and calcium using a Thermo Dionex Aquion™ ion chromatography system. Polymer in produced water was analyzed by nitrogen chemiluminescence using a Shimadzu TOC-L/TNM-L™ unit (Wang et al. 2020; Seright and Wang 2022, 2023a).

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Injected and Produced Water Salinities. The injection water used in the Milne Point polymer floods was Prince Creek water (which we also call "Milne Point injection water"), which has a salinity of about 0.25% TDS. In contrast, the native formation water salinity was about 10 times greater than this value. **Fig. 16** plots salinities of water currently produced from the Schrader Bluff formation of various Milne Point wells. (Each letter on the *y*-axis designates a particular pad associated with polymer injection.) Water has just recently been produced from Well F109 (on the F-Pad), so the salinity (2.85% TDS or 11.4 times the salinity of the Prince Creek injection water) is approximately that of the original Schrader Bluff formation. The other wells have produced water for varying periods of time since the start of either water or polymer injection (always involving Prince Creek water). Typically, the ratio of sodium to calcium (wt/wt) was roughly 50:1; the ratio of calcium to magnesium was roughly 1:4; and very little potassium was present.

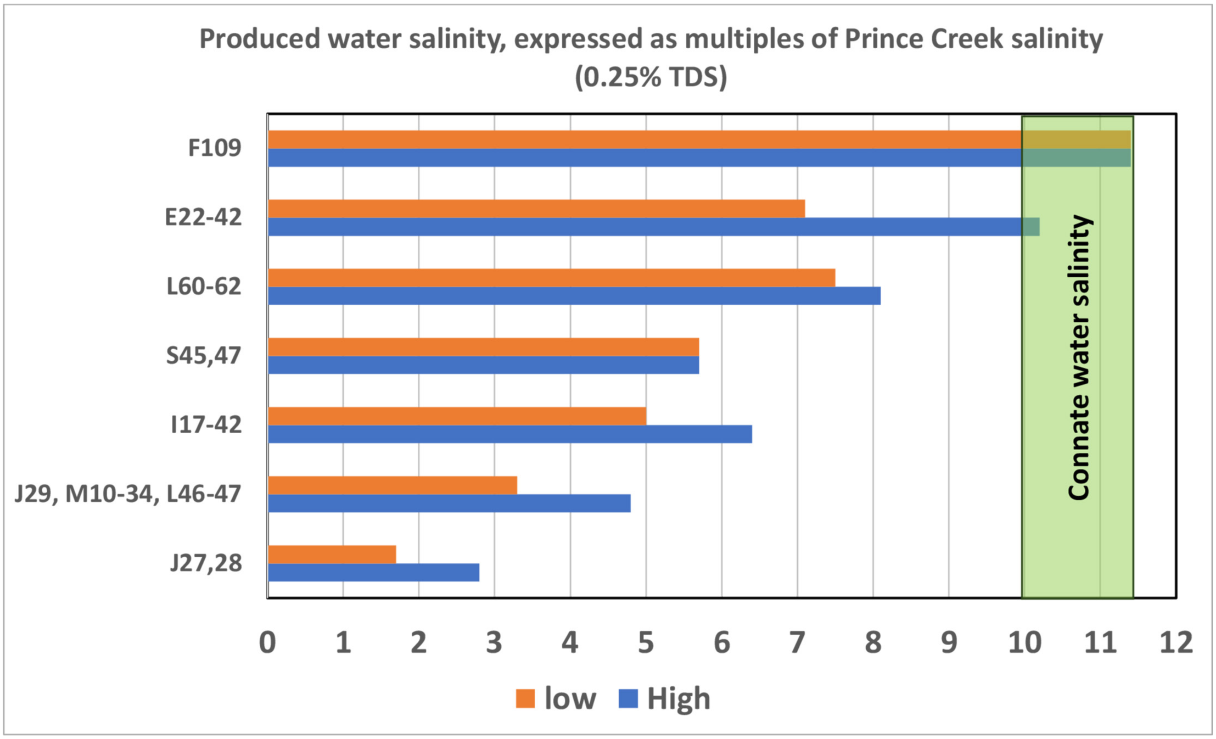

Fig. 16—Salinities produced from Milne Point wells completed in the Schrader Bluff formation, expressed as multiples of the salinity of the injection water (e.g., 1 = salinity of Prince Creek water = 0.25% TDS. 10 = 2.5% TDS).

Polymer Retention "Tailing" Phenomenon. Extensive laboratory studies were conducted to characterize HPAM (Flopaam 3630S) retention on Milne Point (Schrader Bluff) core material (Wang et al. 2020; Seright and Wang 2022, 2023a). These studies consistently demonstrated that illite dominated polymer retention and that a "tailing" phenomenon was observed **(Fig. 17)**. In this tailing phenomenon, injected polymer broke through at the end of a core at the same time as an associated water tracer—indicating that retention did not delay movement of the polymer through the sand. After the first breakthrough of the polymer and water tracer, the effluent tracer concentration rapidly rose to match that of the injected tracer concentration. In contrast, the effluent polymer concentration only rose to about 70% of the injected polymer concentration. Thereafter, the effluent polymer concentration slowly increased over the course of many pore volumes (of polymer/tracer injection) before it finally reached the injected polymer concentration. From a practical viewpoint, this "tailing" phenomenon suggests that polymer retention will not delay movement of the polymer bank (or the associated oil bank) through the reservoir. Because a fraction of the polymer (about 70% in this particular case) propagates through the reservoir rock at the same speed as the aqueous solvent, there will be no water bank (that is completely depleted of polymer) that moves ahead of the main part of the polymer bank. In contrast, some simulators assume that polymer retention will completely remove polymer from the first part of the polymer bank, thus forming a water bank ahead of the polymer bank (Seright and Wang 2023a). If formed, this water bank could channel through the oil and delay movement of the oil bank. Nevertheless, when the polymer bank first arrives at a given point in the reservoir, the effective concentration, viscosity, and mobility ratio will not be as desirable as expected for polymers with the original concentration and viscosity. The polymer concentration and viscosity will gradually rise with increased throughput, but they may not reach the originally intended values over a practical time frame.

L-Pad Results. Produced water salinities and polymer concentrations from the L-Pad are consistent with the "tailing" phenomenon observed in the laboratory. Polymer flooding was initiated in the L-Pad with no prior waterflood. Injection of 2,000-ppm Flopaam 3630 S (dissolved in Prince Creek water) began at the L-Pad in November 2018, with an anticipated polymer/oil mobility ratio near one. Oil (~850 cp) was produced essentially water-free for more than 3 years. Soon after detection of a significant water breakthrough, a sample was collected from Well L62 in August 2022. This sample contained 654-ppm HPAM and 7.9 times the salinity of Prince Creek water. A second sample was collected and analyzed in May 2023 and contained 520-ppm HPAM and 7.5 times the salinity of Prince Creek water. (Similarly, the first polymer breakthrough in Well L57 occurred in late December 2023. At that time, the produced water salinity was five times that of Prince Creek water.) Because the first produced polymer samples had salinities much closer to the original formation water than to Prince Creek water, we assess that the polymer propagated through the formation at the same rate as a water (salinity) tracer—consistent with our laboratory results. Also, since the produced polymer concentration is not rising over time and is significantly lower

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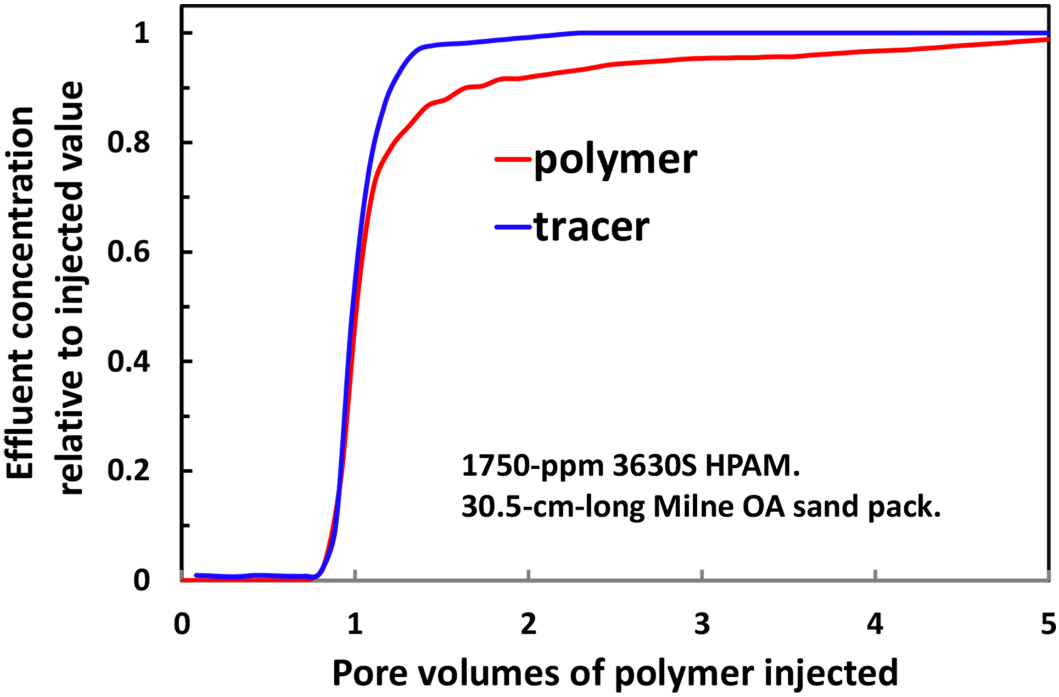

Fig. 17—Illustration of polymer retention "tailing effect" in Milne Point core material.

than the injected HPAM concentration, we assess that the polymer-retention "tailing" phenomenon was occurring—as in our laboratory experiments. No polymer-free water has been injected and no active aquifer is present in this area, so dilution by alternative water sources could not account for the produced polymer concentration being 26–33% of the injected polymer concentration. Why was the produced polymer concentration not 70% of the injected value instead of 26–33%? One possibility is that this particular pattern contains a higher illite content than present in our core experiments. Another possibility is that the observed polymer concentration is low simply because polymer has just arrived at the production well and may rise to stabilize at a higher value in the coming months. Additional monitoring of produced fluids should clarify this issue.

J-Pad Results. Salinity changes in the produced water can give a qualitative indication that polymer injection is improving sweep efficiency. At the J-Pad, about 0.1 pore volumes of Prince Creek water was injected before starting polymer injection in August 2018. Water cuts in offset producers (J27 and J28) quickly rose to as high as 70% soon after injecting water. After the start of polymer injection, water cuts in Wells J28 and J27 declined over the next 2 years, reaching values as low as 5% **(Figs. 18 and 19)**. A polymer breakthrough

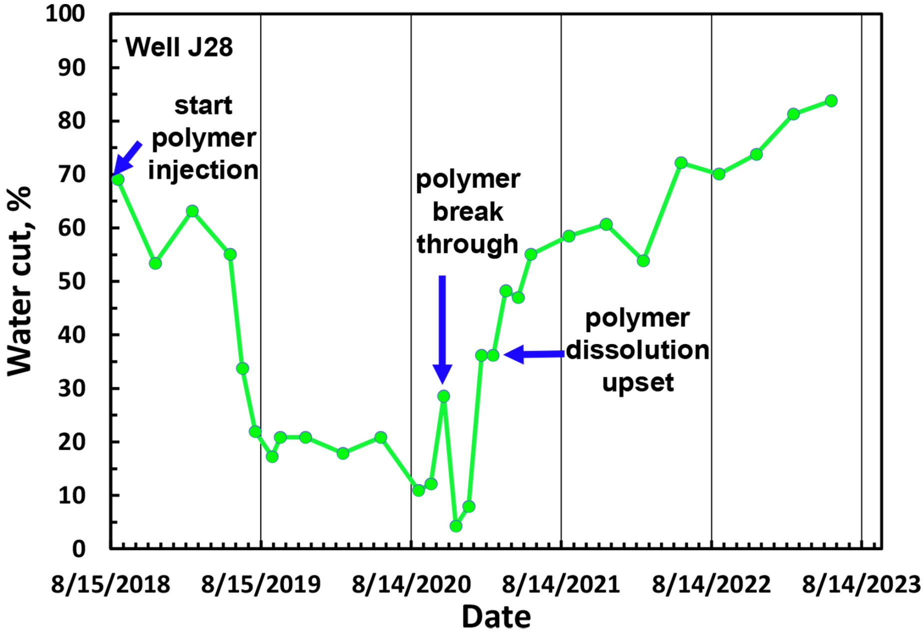

Fig. 18—Water cuts for Well J28.

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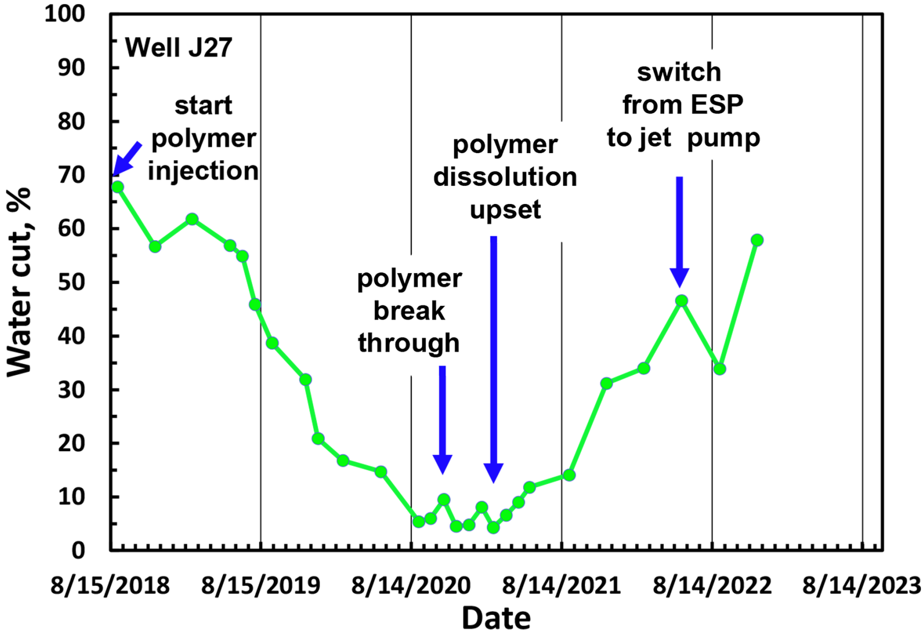

Fig. 19—Water cuts for Well J27.

was noted in October 2020, in Well J27, and in December 2020, in Well J28. After polymer breakthrough, water cuts increased fairly rapidly in Well J28 and more gradually in Well J27.

Figs. 20 and 21 plot salinities for Wells J28 and J27, respectively—expressed as produced sodium concentration [Na] relative to injected sodium concentration (associated with the Prince Creek water). Note in **Figs. 16, 20, and 21** that the produced salinities in Wells J28 and J27 are much lower than the original formation water—indicating severe channeling of the injected water from injectors to producers (either due to viscous fingering or through a fracture-like feature). In both J28 and J27, the produced salinity increased between the start of polymer injection and polymer breakthrough—by 27% in Well J28 and by 19% in Well J27 **(Figs. 20 and 21)**. This increase in salinity confirms that the polymer flood is improving sweep efficiency during this period. Specifically, as polymer injection progresses, the polymer is pushing into unswept portions of the reservoir and driving a greater fraction of oil and the original formation water to the producers. After polymer breakthrough, **Figs. 20 and 21** reveal a sudden drop in salinity. Thereafter, salinity was reasonably constant or began to decline—consistent with the post-polymer-breakthrough water-cut behavior in **Figs. 18 and 19**. In Well J27, the ESP was replaced in mid-2022 with a jet pump. The power fluid used to drive the jet pump was notably more saline than the produced water—accounting for the sudden salinity increase in August 2022 in **Fig. 21**.

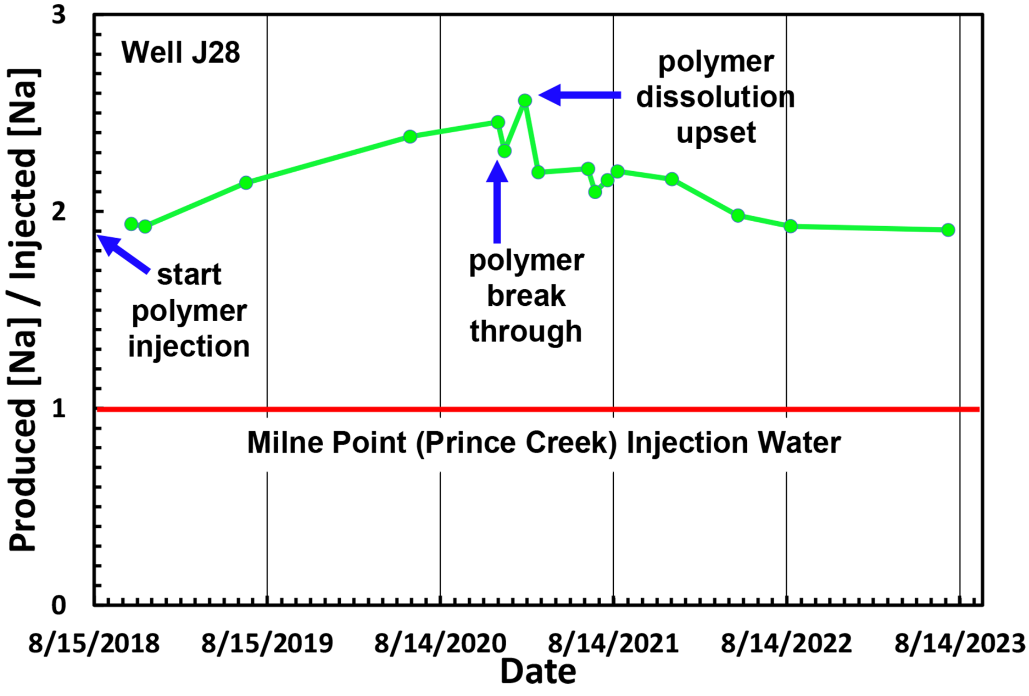

Fig. 20—Produced salinities for Well J28.

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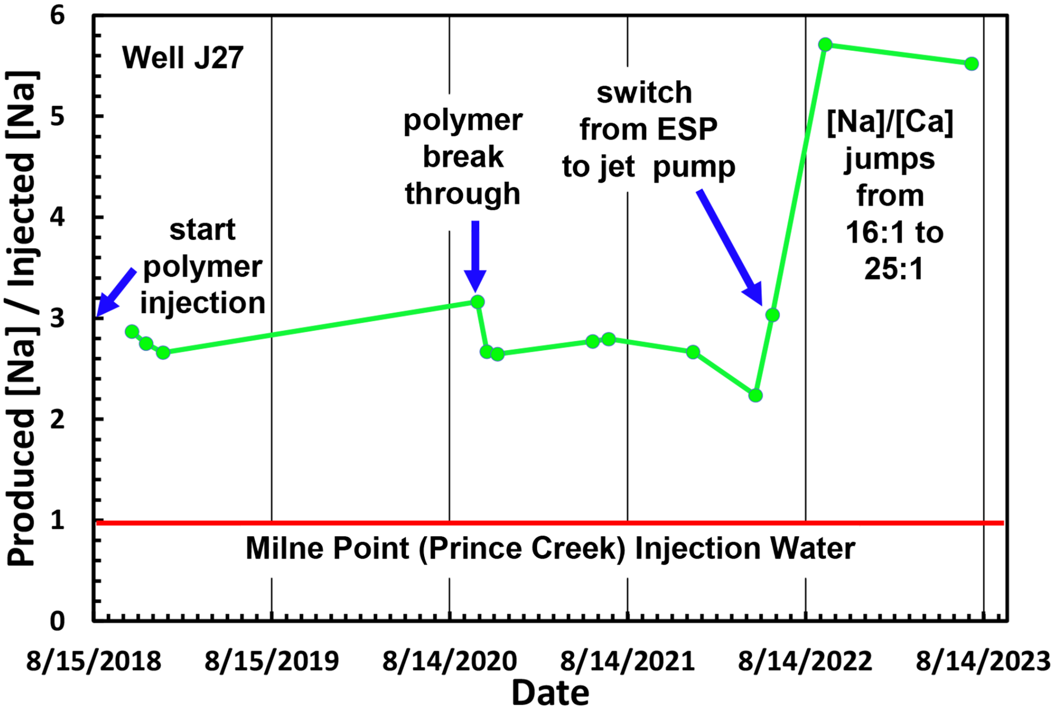

Fig. 21—Produced salinities for Well J27.

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E-Pad, F-Pad, I-Pad, M-Pad, S-Pad, and R-Pad. Polymer injection into E-Pad, F-Pad, I-Pad, M-Pad, S-Pad, and R-Pad was not initiated until 2020 to 2024. To date, no polymer has been produced from these pads, and no significant salinity changes have been noted in the produced waters.

We are aware of the oil/water separation problems that have been reported by others after polymer breakthrough (Kumar et al. 2016; Mehta et al. 2016; Mittal et al. 2018; Prasad et al. 2022; Shankar et al. 2022). Although extensive laboratory studies have been performed to mitigate the problems when they occur Dhaliwal et al. 2021, 2022), no polymer-induced oil/water separation problems have occurred to date because the polymer concentrations are too dilute at the time that they reach the central water processing facility. However, this concern is anticipated to grow after a polymer breakthrough occurs in the various polymer-flooded patterns.

At present, molecular weight distributions (Seright et al. 1981) of produced polymer samples would be compromised because the polymer is extensively degraded upon passing through either ESP or jet pumps. However, our laboratory studies to date indicate no measurable chromatographic separation upon passing through Milne Point core material (Wang et al. 2020; Seright and Wang 2022, 2023a).

Relevance to Other Polymer Floods

The observations and conclusions from this paper, of course, are directly applicable to the Milne Point polymer flood. We hope that insights from our project will be useful to others during future polymer floods, but that will depend on the specific conditions of the other fields. Use of localized skids for polymer dissolution made sense at Milne Point because of the substantial distances between injection locations (e.g., ~9 miles between M- and S-Pads) and notable differences between pattern oil viscosities (i.e., 10–1,300 cp). In contrast, centralized polymer makeup facilities were judged more appropriate for Daqing, China, and Mangala, India, and other fields throughout the world (Wang et al. 2009; Prasad et al. 2022). Use of nitrogen blankets to prevent oxidation/corrosion generally should be utilized for cases where polymer makeup water contains dissolved iron, but field applications exist (e.g., Daqing, China, and Tambaredjo, Suriname) where nitrogen blankets are not needed because the water does not contain dissolved iron and reservoir temperatures are low (Wang et al. 2009; Manichand and Seright 2014). Use of wellhouses to protect individual wellheads and pumps was essential at Milne Point because of the arctic cold, but probably will not be needed in warmer climates. Concerning polymer retention, our choices during analysis of produced fluids were strongly affected by the "tailing" phenomenon associated with high reservoir illite content (Seright and Wang 2023a) and the substantial salinity difference between the injected polymer and the connate water. Those choices could be different in other reservoirs if clays are not present or salinity contrasts are minimal. If polymer is supplied as an emulsion instead of as powder, the mixing/dissolution facilities may be completely different. For cases where polymer is supplied as powder, fairly general applicability (to field applications of polymer flooding) may be found for our observations regarding skid uniformity and ease of operation, mixer and pump reliability, use of inline mixers to blend mother solutions, and increased flexibility when dedicating one injection pump per well.

Conclusions

The following conclusions were noted from our experiences at the Milne Point polymer flood:

1. Compared with bulk 500–750-kg polymer bags, silos greatly improved the storage capacity and increased the overall quality of polymer hydration in the system. Silos also required less physical effort when transferring polymer.
2. Polymer hydration skids that were made in-house by the polymer supplier were more reliable and experienced fewer polymer solution quality and startup issues than those that were outsourced. These in-house skids also used a uniform programming software that made it relatively easy to train the operators on new hydration skids.
3. For pumping polymer mother solution, triplex pumps provided the best runtime and were the most maintenance-friendly, compared with diaphragm or triple screw pumps.

4. Although polymer solutions could be prepared that met our target viscosities without using a nitrogen blanket, corrosion and iron particulates raised substantial reliability and injectivity concerns if nitrogen blanketing was not used—especially when using black-iron piping and when the makeup water contained dissolved iron.
5. Inline static mixers were ineffective in mixing mother solution with dilution water when the mixing occurred close to the wellhead. Mixing the two streams too close to the wellhead led to substantial variations in wellhead viscosity measurements.
6. Dedicating individual pumps for injection into a given well provided desirable flexibility in controlling rates and concentrations of polymer for the well.
7. Monitoring produced salinity and polymer concentration provided useful insights about improved sweep and polymer retention associated with the polymer flood. The observed field behavior was consistent with laboratory studies indicating a "tailing" phenomenon associated with polymer retention at Milne Point.

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