PAPER: 2007-184

Polymer Flood Application to Improve Heavy Oil Recovery at East Bodo

F.R. WASSMUTH
Alberta Research Council
W. ARNOLD
Pengrowth Corporation
K. GREEN
Alberta Research Council
N. CAMERON
Pengrowth Corporation

Abstract

The East Bodo, Lloydminster SS heavy oil pool has been exploited using primary recovery and waterflood. IOR screening showed that a polymer flood would be a preferred IOR technique. Subsequent coreflood tests indicated that the polymer flood could recover 20% OOIP incremental oil, after waterflooding, to a 95% water cut. Data gathered from the coreflood was used to fine tune the reservoir simulation model to help design the pilot and predict potential economic reserve capture for a commercial field-wide polymer flood. Subsequently, a pilot was initiated. During the pilot operation, achieving the target polymer viscosity, dependant on water quality, proved to be a significant challenge. Early field response is being observed through an increase in injection pressure, reduced water cut and polymer breakthrough. Further positive response of this polymer pilot allows for the expansion of the polymer flood technology to other parts of this reservoir; some with bottomwater and gas cap. This paper reviews the progress of the East Bodo polymer flood, from laboratory concept to working field application, in four major steps: 1) IOR screening using simulations and coreflooding, 2) field pilot design/implementation, 3) pilot performance, and 4) next steps.

Introduction

Pengrowth has targeted East Bodo (Alberta side) and Cosine (Saskatchewan side) for waterflood optimization and subsequent enhanced oil recovery applications. Currently, the most practical EOR technology for this heavy oil reservoir seems to be the polymer flood technology in combination with horizontal wells. Several investigators[1-4] have demonstrated the potential of the polymer flood technology for improved oil recovery in heavy oil reservoirs.

The East Bodo/Cosine Reservoir produces from the Lloydminster Formation, which is part of the Lower Cretaceous Mannville Group. Pengrowth provided some of the reservoir characteristics, as summarized in Table 1. This particular reservoir is separated into two parallel lobes trending North/West to South/East.

To complicate matters, local gas caps are found primarily on the Saskatchewan side of the reservoir. Thus, the current waterflood patterns are located on the Alberta side. In the future, optimized waterflood and EOR schemes need to include those parts of the reservoir which are overlain by gas caps or influenced by bottomwater. A plan of progression aligned with the priorities of Pengrowth was laid out as follows:

- Optimize existing waterflood;
- Step out waterflood into limited gas cap areas;
- Then, target areas with a more extensive gas cap;
- Determine enhanced waterflood potential, for instance polymer flood; and
- Arrange well patterns to benefit both waterflood and subsequent EOR process.

IOR Screening

Several IOR technologies were considered for application in the East Bodo Field. What follows is a list of IOR processes that were initially considered, but screened out after technical or economical issues could not be overcome.

1) Thermal Recovery: Pay is too thin – heat loss to overburden is too large; oil not viscous enough to form a stable steam chamber; fireflood has potential but no expertise at hand.
2) Miscible Solvent Applications (VAPEX): Challenges are operations and capital cost; no commercial analog data available; low reservoir pressure and conformance issues. Net pay is too thin for successful gravity drainage.
3) Microbial EOR: Novel technology with good potential; prefer to monitor commerciality before pursuing. Risk associated with introducing organisms in reservoir that eat oil?
4) Waterflood: Successful analogs have recovered +20% OOIP. Concerns include: viscous fingering through viscous oil zone, injection water may channel into the water leg, bypassing oil, mechanical conformance (vertical wells vs. horizontal).

TABLE 1: Reservoir characteristics.

Reservoir Parameter	Value
Lloydminster formation	Marine shoreface from lower Cretaceous fine-med. grained, 80 – 90% quartz sand, with minor feldspar, chert, kaolinite
Permeability	1,000 mD
Pay porosity	27% min. to 33% max., average = 30%
Oil zone water saturation	26% min.
Initial reservoir pressure	~6,800 kPa
Oil viscosity	600 to 2,000 cP (14 API)

PEER REVIEWED PAPER ("REVIEW AND PUBLICATION PROCESS" CAN BE FOUND ON OUR WEBSITE)

TABLE 2: Summary brine compositions.

Brines	Na^+	Ca^{2+}	Mg^{2+}	Cl^-	HCO_3	TDS
Water tanks, East Bodo	8,930	279	188	15,191	557	25,226
McLaren water, south	9,200	178	161	14,943	828	25,400
Sparky water	9,600	234	175	16,272	399	26,800
East Bodo, prod. well	10,460	423	253	17,594	309	29,000

TABLE 3: Summary of polymer rheology measurements.

Polymer	Conc. (ppm)	S. Bodo (mPa·s) $7s^{-1}$	S. Bodo (mPa·s) $10s^{-1}$	E. Bodo (mPa·s) $7s^{-1}$	E. Bodo (mPa·s) $10s^{-1}$
F3630	-HPAM, molecular w.18 million Daltons, hydrolysis 32%				
F3630	500	7.5	7.1	10.4	8.1
F3630	1,000	14.6	12.7	17.1	15.4
F3630	1,500	22.7	20.2	22.7	21.2
F3830	- HPAM, molecular w. > 20 million Daltons, hydrolysis 30%				
F3830	500	7.2	5.8	7.4	7.9
F3830	1,000	17.3	15.1	17.1	14.4
F3830	1,500	30.0	25.5	29.6	25.2

5) Alkaline Surfactant Polymer (ASP) Flood: Need to soften water for alkaline, which requires greater Opex and Capex. Questions over predominant recovery mechanism arise? Is the increased oil production due to conformance by polymer or reduced interfacial tension from the alkaline and surfactant.

In light of these concerns, the polymer technology proved to be the most promising technology to investigate first, for two main reasons.

i) The polymer solution viscosity corrects the poor water/oil mobility ratio responsible for conformance control issues and poor waterflood performance on intermediate heavy oils[1, 5].

ii) In combination with horizontal wells, polymer formulation can be injected at high rates to produce heavy oils at economic rates[2, 4].

If the polymer technology can be successfully applied in the East Bodo Reservoir, then more complex chemical flood variations can be investigated, such as surfactant polymer flooding, alkali polymer flooding and ASP. In any event, the polymer flood response would serve as a baseline by which the effectiveness of the other processes can be measured.

Polymer Laboratory Evaluations

The objective of this study was to determine the polymer flood potential in Pengrowth's East Bodo Reservoir through coreflood tests. A waterflood was conducted first on a single core, followed by a polymer flood. In this procedure, the incremental recovery of the polymer flood above waterflood recovery is clearly defined. The coreflood was conducted on reservoir core samples selected by Pengrowth with synthetic brine and oil samples from the East Bodo Reservoir to match reservoir conditions.

The East Bodo water quality from the new target area and its compatibility with the polymer solutions had to be addressed before the coreflood work could go ahead. Injection and production water samples were analyzed and checked for compatibility issues.

Water Analysis

Four water samples from the surrounding area of the East Bodo Reservoir were analyzed for ion composition (see Table 2). The total dissolved solid content ranged from 25,000 to 29,000 ppm, with hardness ion concentrations (Ca++ and Mg++) ranging from 350 ppm to 650 ppm. Hardness ions significantly reduce the effectiveness of the polymer viscosity and, in sufficient concentrations, may lead to precipitation of the polymer. The formation of carbonate scales with hardness ions may also be a factor. Thus, polymer precipitation and scale formation needs to be watched out for during the bench top experiments.

TABLE 4: Core properties.

Core Properties:	CF #1
Length, cm	26.35
Diameter, cm	3.81
Area, cm^2	11.40
Bulk volume, cm^3	300.41
Porosity, ϕ	0.30
Core temperature	23
Air permeability, mD	1,856
Brine permeability, mD	1,370

Noticeably absent in the analyses was the presence of iron; iron was not detected. This is not surprising since the water samples were exposed to air for several days before the analysis took place. This exposure causes the iron to precipitate such that no dissolved iron will be detected. To determine accurate dissolved iron concentrations, measurements need to be done onsite. Such onsite measurements were conducted when the exact water source was identified.

Polymer Rheology

A summary of the rheology measurements for two partially hydrolyzed polyacrylamide polymers (HPAM) at three concentrations is listed in Table 3. The viscosity of the polymer solutions is shear dependent. At low shear rates (<0.1 s^{-1}), the polymer solutions behaved like a Newtonian fluid. At higher shear rates (>0.1 s^{-1}), the polymer solutions demonstrated shear-thinning behaviour. At nominal injection rates, the shear rate within a sandstone core ranges from $7s^{-1}$ to $10s^{-10}$. Viscosity measurements for these crucial shear rates have been summarized in Table 3.

Water and Polymer Coreflood

During the waterflood stage, 1.1 pore volumes of water were injected into the East Bodo Reservoir core at a flow rate of 2 ml/hr. The reservoir core properties have been summarized in Table 4. Water breakthrough occurred after less than 0.1 pore volumes of water had been injected into the core. After 1.1 pore volumes of water injection, the oil recovery reached 34% OOIP with the water cut approaching 95% (see Figure 1).

Subsequently, close to 2 pore volumes of polymer solution, at a concentration of 1,500 ppm, were injected into the core after the initial waterflood (see Figure 1). Injecting the polymer formulation with an effective viscosity of 25 mPa·s, at a rate of 2 ml/hr, caused a rapid pressure increase. The oil was banked ahead of the polymer front, and the water cut decreased to 40%. The oil

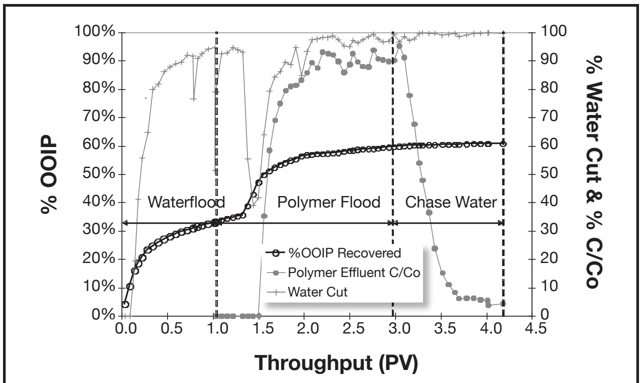

FIGURE 1: Waterflood and polymer flood production profiles.

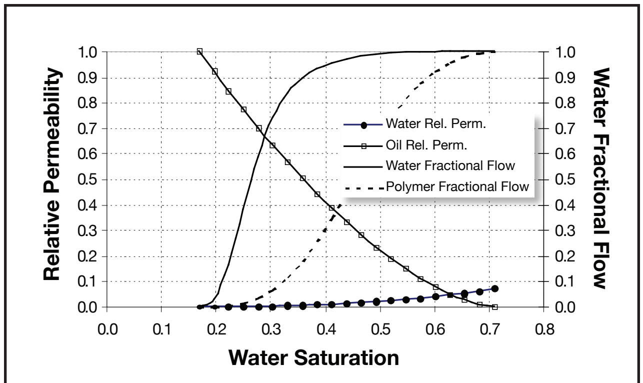

FIGURE 3: Relative permeability curves and fractional flow curves.

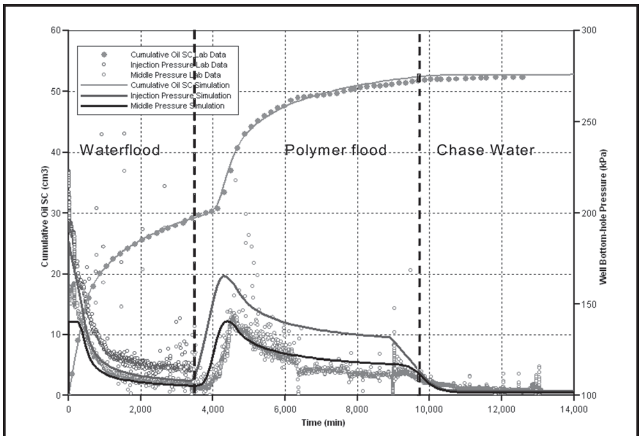

FIGURE 2: History matched waterflood and polymer flood production profiles.

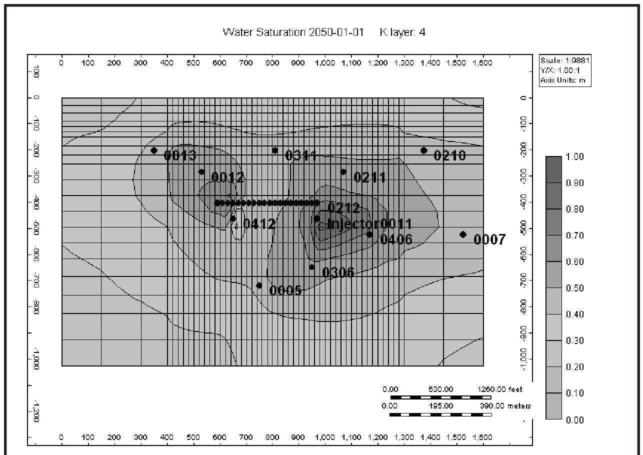

FIGURE 4: Areal view of simulation pattern 11-14-37-01W4.

production increased to the point where an incremental 20% OOIP were produced after ½ a pore volume of polymer injection. At the end of the 1.8 pore volume polymer slug, a total of 59% OOIP had been recovered. The polymer breakthrough occurred shortly after the polymer flood began; after 0.5 pore volumes of polymer had been injected the effluent polymer concentration reached 50% of the injected value. Based on the mass balance of the polymer, injected minus produced, the retention of the polymer in the core was relatively small. In situ, approximately 2.5 mg of polymer adsorbed for every 100 g of rock.

History Matching Coreflood Results

The oil recovery and polymer front propagation during the polymer flood was history matched using the reservoir simulator, STARS. Oil recovery and pressure drop were two components that were matched with the simulator in Figure 2.

The viscosity of the live oil, water and polymer solution was 950 mPa·s, 1 mPa·s and 25 mPa·s, respectively. The relative permeability curves used to achieve the history match for the waterflood and subsequent polymer floods, are shown in Figure 3. Based on the shape of the relative permeability curves, the core is water wet, $k^o_{rw} = 0.1$. The water and polymer coreflood parameters were used to calibrate the field scale simulation model described in the next section.

Field Scale Simulations

In order to demonstrate the potential of the polymer flood, two sets of simulations were conducted:

1) Simulate the impact of a polymer pilot applied to an existing waterflood pattern.
2) Optimize the polymer technology with horizontal wells in an undeveloped section of the reservoir.

TABLE 5: History match simulations.

Parameter	
Injectors: Producers	1:12
Pattern length, m	1,600
Pattern width, m	1,025
Depth, m	794
Pay thickness, m	3.2 ave.
Porosity	0.29 ave.
OOIP, SC m^3	988,078
Horizontal permeability (k_h), mD	1,500
Vertical permeability (k_v), mD	100
Anisotropic permeability, mD	700
Maximum injection rate, m^3/day	286
Initial water saturation	0.28
Initial oil saturation	0.72
Irreducible oil saturation	0.30
Dead oil viscosity, mPa·s	1,128
Live oil viscosity, mPa·s	417

Converting Waterflood Pattern to Polymer Pilot

Thirteen oil production wells and one water injection well were used in the history match of the water injection pattern, as mapped in the areal simulation grid shown in Figure 4. The cross-section of the sand bar was modelled with the varying grid spacing. The pattern spanned 1,600 m in length and 1,000 m in width, with a maximum pay thickness of 6 m. The basic reservoir parameters used in the field-scale simulations are listed in Table 5.

The history match of primary and waterflood recovery was achieved by adjusting the gas/oil and water/oil relative permeability curves. The overall match of the primary and waterflood recovery for the whole pattern is compared in Figure 5 for the period from 1996 to 2005. The horizontal producing well, ‘02/12’, running diagonally across the injection pattern, showed early

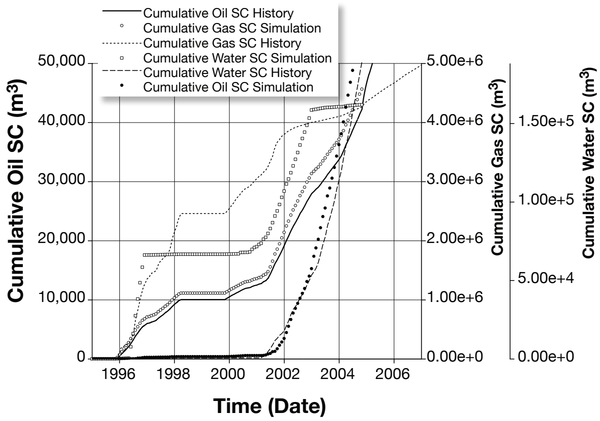

FIGURE 5: History match of oil, gas and water recovery from pattern 11-14-37-01W4.

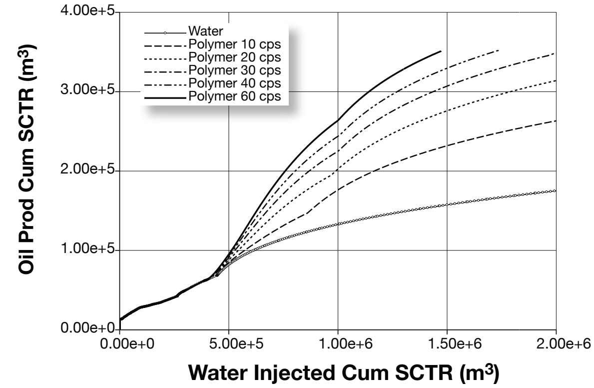

FIGURE 7: Impact of polymer viscosity on oil production (cumulative water injected).

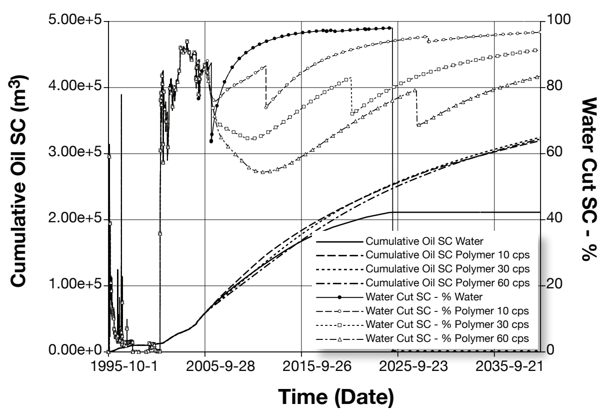

FIGURE 6: Effect of polymer viscosity on oil production and water cut.

water breakthrough and was shut in 2001 after 5 years of intermittent production. In these simulations, a discretized horizontal well model was used to allow the horizontal wellbore to conduct fluids, even after the horizontal well was shut-in. This improved the match of early water breakthrough at wells ‘0005’ and ‘0306’. After establishing a reasonable match on primary and waterflood recovery, the simulation model was used to generate water- and polymer flood predictions.

For the waterflood prediction, it was assumed that sufficient water was available to maintain a maximum injection rate of 600 m^3/d. No shut-in wells were reopened and producers were shut-in when their water cut reached 98%.

Polymer injection started in 2006/01/01 with a polymer solution generating an effective viscosity of 37.5 mPa·s and a bottomhole pressure limited at 20 MPa. In order to increase the injection rate, vertical wells ‘04/12’ and ‘04/06’ were also converted to injectors when their water cuts surpassed 98%.

Water- and polymer flood predictions using the vertical well injectors are shown in Figure 6. The cumulative oil recovery of the polymer flood does not outperform the waterflood until the year 2020. However, the polymer flood produces approximately half the water compared to the waterflood. The main reason for the water and polymer injection rates to be abnormally high for this pattern is that the passive horizontal wellbore buried in the reservoir allows for the distribution of the injected water or polymer along its trajectory.

The impact of polymer viscosity on cumulative oil production and water cut are also shown in Figure 6. Obviously, the higher the polymer viscosity, the lower the produced water cut. The saw tooth pattern in the water cut arises from shut-in production wells after water cut reached 98%. The oil production rate did not improve with increased polymer viscosity since the injection of the various polymer formulations were pressure limited; i.e., all three polymer solutions maintained the maximum pressure gradient between injector and producer.

TABLE 6: Well configurations.

Config.	Inj.	Prod.	Fig.
Vertical Wells Line Drive	3 v	7 v	Figure 8
Crosswise Horizontal Injector	1 hw	7 v	Figure 9
3 Lengthwise Horizontal Wells	1 hw	2 hw	Figure 10

In Figure 7, the cumulative oil production is re-plotted as a function of cumulative water injected. The impact of the polymer flood on reducing the water usage is clearly evident in this figure. If you consider injecting just over a pore volume of water (1.5 million m^3), then you could expect to produce approximately 16% OOIP (160,000 m^3). Injecting the same amount of polymer solution at 40 mPa·s would produce twice the amount of oil (32% OOIP or 320,000 m^3).

Optimizing Horizontal Well Configurations

The second part of the simulation study focused on evaluating the use of vertical and horizontal wells to optimize the oil recovery from potentially new patterns with water- and polymer flood applications. The same simulation parameters obtained from the history match for the waterflood pattern were used in these simulations. The injection rate was limited at a maximum rate of 500 m^3 for each injection well (horizontal or vertical); the maximum bottomhole injection pressure was set at 20 MPa, with a maximum production rate of 200 m^3/day per well.

The simulated well configurations with combinations of vertical and horizontal wells are summarized in Table 6. The figures cross-referenced in Table 6 (Figures 8, 9 and 10), show individual well locations and the remaining oil saturation at the end of the polymer flood.

When simulating the waterflood, the line drive configuration with vertical wells provided the quickest oil recovery and the best sweep efficiency, since the complete pattern was swept even at the edges. For a polymer flood, the use of three parallel, horizontal wells with a central injector provided the optimum configuration since the fastest oil recovery was achieved in comparison to the other configurations, as shown in Figure 11. By the year 2020, polymer flood with the horizontal well configuration recovered 200,000 m^3 of oil, while the line drive vertical well configuration recovered only half the amount of oil at the same time.

Surprisingly, the vertical well configuration still provided the best sweep efficiency for the polymer flood since the edges of the horizontal well patterns were not completely swept. However, the polymer injection rate was severely limited when using vertical wells and the parallel horizontal well configuration was the more attractive alternative when injecting polymer into the reservoir to produce heavy oil at economic rates.

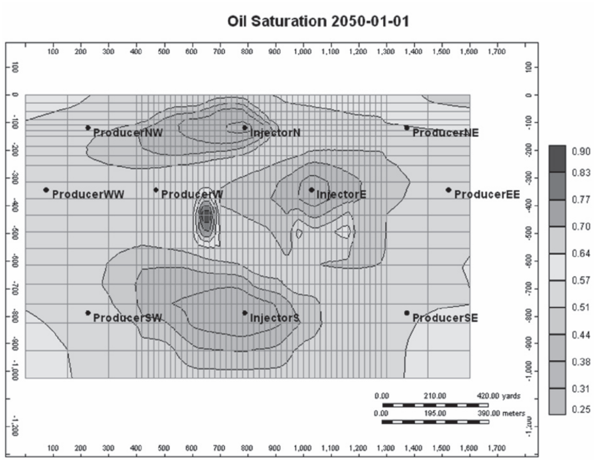

FIGURE 8: Line drive (east-west) with vertical wells.

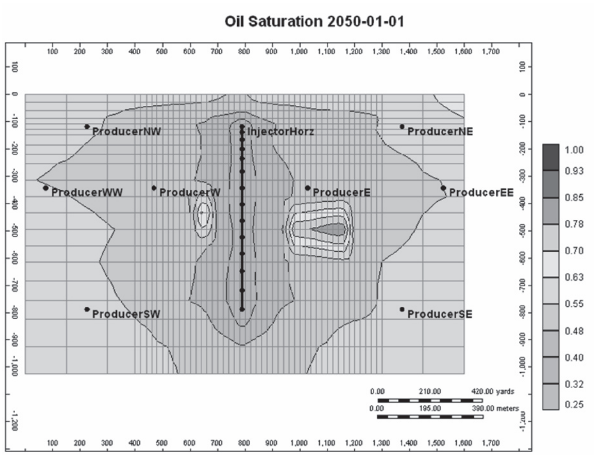

FIGURE 9: Crosswise horizontal injector.

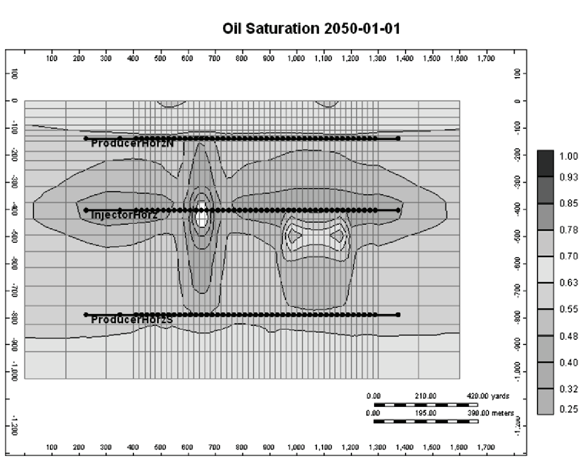

FIGURE 10: 3 Lengthwise horizontal wells.

Pilot Design and Implementation

The simulation and core flooding results encouraged Pengrowth to proceed with a field pilot. This entailed choosing an area of the field in which to pilot, scoping the polymer mixing and injection equipment, and procuring, installing and commissioning this equipment.

The 11-14 pattern, shown in Figure 12, was identified as the most appropriate area of the field to implement the polymer pilot for the following reasons:

1. Mature Waterflood Area.

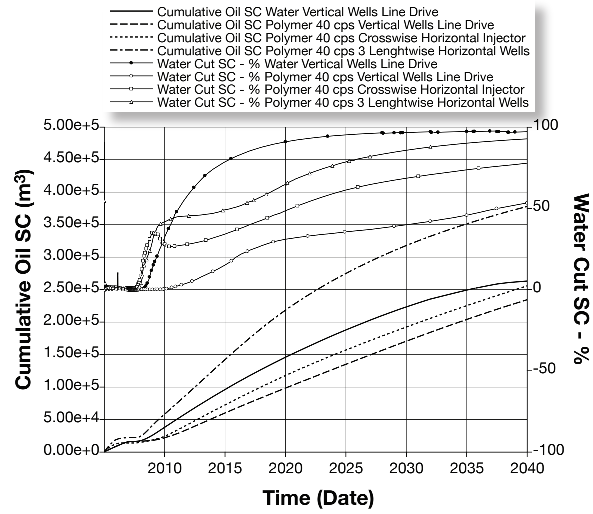

FIGURE 11: Polymer flood results (oil and water cut) for several well configurations.

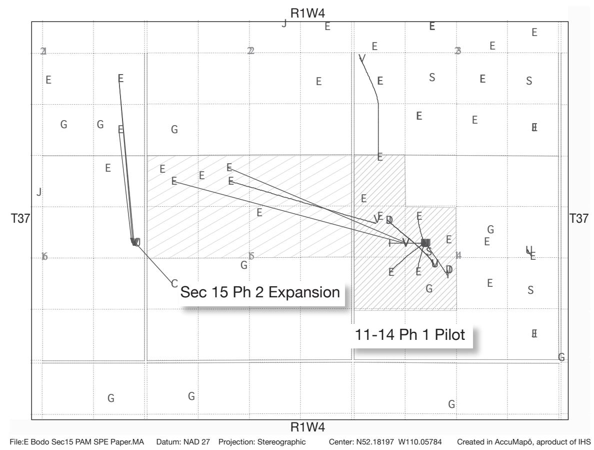

FIGURE 12: Phases 1 and 2 polymer flood pilot in East Bodo.

a) Waterflood was initiated in this pattern with an extensive production history.
b) High recovery factor, so the risk of jeopardizing waterflood recovery in the event of polymer pilot failure would be mitigated.
c) Reduction of water cut from 98% would indicate incremental oil being swept.
d) This pattern has the highest injectivity for the field due to well spacing, an abandoned horizontal well acting as a conduit and high water saturation from previous water injection.

2. Surface facilities had previously been set up at this site, with sufficient lease area, electric power service, secondary containment, etc.
3. This pattern has two water source wells in close proximity that allowed us to isolate the water source and allowed closer scrutiny for quality control purposes. The alternative would be to access the waterflood supply that is made up of varying volumes of three source waters.
4. The reservoir immediately to the west of the 11-14 pattern, in Section 15, had yet to be developed on waterflood. After successful completion of the initial polymer pilot, Phase 2 of the polymer pilot would incorporate horizontal wells; Section 15 was the logical candidate for this.

Incorporating Phase 2 into the polymer pilot, using horizontal wells on Section 15, allowed economy of scale in designing the polymer mixing and injection equipment. Thus, the capacity of the polymer mixing equipment was essentially over-designed for Phase 1 of the polymer pilot, but it allows for immediate expansion to the second phase. As a result, the overall equipment cost was reduced by approximately 40%.

The strategy in choosing an equipment design philosophy was to provide every opportunity for the pilot to succeed. The design of the make down and injection equipment was based on a comprehensive process control and data gathering ability. Although this comes at a premium, it ensured the pilot didn't fail because of equipment problems. The equipment would be skid mounted for ease of installation and to provide mobility to move the equipment to new pilot areas. The pilot skid would be replaced with an inexpensive, simplified, 'fit for purpose' design that would allow for economic optimization.

The pilot skid provides polymer-specific solution injection rates up to 150 m^3/d, independent polymer concentration and pressure for each of three output streams. A manifold at the outlet allows the individual streams to recombine, thus, providing a flow range from 15 m^3/d to 450 m^3/d. The maximum blended injection ratio is 2,000 ppm at 450 m^3/d. The maximum injection pressure is 7,650 kPa, or 10% higher than the maximum surface waterflood injection pressure allowed.

The process flow of the skid allows for bulk handling of 750 kg bags of granular polymer. The granular polymer is mixed with the source water at a specified stock solution concentration and aged in a dual train tank system. The hydrated stock solution is then fed into one of three dilution legs where it is blended down to a specific concentration and injected at a specific rate and/or pressure. The diluted water is filtered at twenty five microns to capture any fish eyes and prevent plugging of the sand face.

The source water is processed off skid through a cascading atmospheric dual 750 bbl tank system to remove oil and excess solids. Before the water is used in any process on the skid, it is filtered to a one micron level.

Pilot Performance

The injection of polymer was initiated in May 2006. The initial targets for the pilot were the ability to mix the polymer solution at a field-scale, to demonstrate there were no injection problems and to ensure there was no undue polymer adsorption onto the rock face. Secondary measures of success would include higher resistance to injection than water, reduced water cut at the produced wells and, finally, increased oil recovery.

There are two readily available sources of water: Sparky and waterflood water. The waterflood water is a combination of produced water from the Lloydminster zone, produced water from trucked-in McLaren zone wells and make-up water from the Sparky water source zone. The chemical composition of these waters is provided in Table 2. The Lloydminster zone is slightly sour, so for safety concerns, this water source was ruled out and the on-site Sparky water was chosen. The Sparky water made a consistent polymer solution in the field, with good injectivity into the reservoir and low polymer adsorption/retention at the sandface. Polymer has broken through at concentrations of approximately 100 ppm at the nearest producing wells.

By far the largest challenge was dealing with the quality of the source water to mix viscous polymer solutions. The dissolved iron content of the water was underestimated, and so, combined with the hardness, the resultant viscosity yield was lower than anticipated. It is difficult to obtain accurate steady-state iron measurements, given its propensity to drop out of solution in the presence of air. The maximum viscosity produced was 10 cP at 1,500 ppm. This viscosity, combined with the 100 m^3/d deliverability of the Sparky wells, made it difficult to show resistance to injection. Iron precipitation in the atmospheric tanks was enhanced by injecting low concentrations of sodium hydroxide to increase the pH. This helped slightly, but resulted in excessive filter and line plugging problems as a small amount of over treating also dropped out the calcium and magnesium. The target was to increase the pH from 7.8 to 8.7. If the pH reached 9, carbonate scaling was massive. The sodium hydroxide treating was abandoned.

In order to achieve higher solution viscosities, it was decided to use Ribstone Creek source water. Using Ribstone Creek source

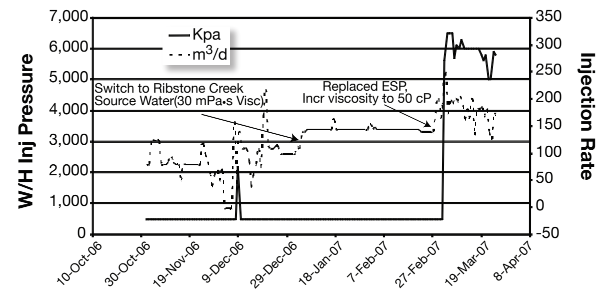

FIGURE 13: Injection pressure response during polymer injection.

water, the viscosity of the blended polymer solution increased to 60 cP at 1,500 ppm. The Ribstone Creek is at a depth of 270 m and has a TDS of about 3,700 ppm. It is classified as groundwater by Alberta Environment and requires a groundwater diversion license (GDL). Pengrowth has a GDL from a previous thermal recovery process. Currently, the water is trucked from the source well to the mixing facility. Plans are underway to bring in the Ribstone Creek water by pipeline for continuous use in the pilot.

After fill-up was achieved and a voidage replacement ratio of 1 was maintained in the pilot area, the injection pressure increased dramatically, as shown in Figure 13. The wellhead injection pressure increased to 6,000 kPa at 200 m^3/d of polymer. Previously, a similar injection pressure was achieved with water at a rate of 250 m^3/d. While maintaining the maximum surface injection pressure, it is expected that the injection rate will drop further as the viscous polymer solution propagates further into the reservoir.

Next Steps

Positive results from Phase 1 of the pilot will pave the way for the Phase 2 expansion of the polymer flood. The Phase 2 expansion will make use of the synergy between horizontal wells and polymer technology applied in heavy oil reservoirs. The optimized, length-wise horizontal well pattern, discussed in the previous simulation section, will be implemented during Phase 2. Since the polymer mixing skid is already on location and operating, a quick start-up of Phase 2 is possible when the decision is made to proceed.

The mixing of viscous polymer formulations is a necessity for polymer floods in heavy oil reservoirs to be effective. Achieving this viscosity at the lowest polymer concentration or cost is a key parameter in optimizing the economic return of the polymer flood. Currently, relatively fresh water is being used to generate such viscous polymer solutions for the pilot application. Expansion of the polymer applications at East Bodo will require us to use produced water or saline source water. In order to generate viscous polymer solutions with these saline brines, two options are being actively pursued:

1. Consider effective water treatment techniques that reduce the hardness/salinity/iron content of the water. These treatment options need to be researched with regard to their practicality and cost effectiveness in the oil industry.
2. Using salinity tolerant polymers such as associative polymers that generate high viscosities in saline brines. These polymers are still experimental products that have not been rigorously lab and field tested, but show good potential.

The final frontier for polymer applications in the East Bodo Field will be the expansion of the technology into parts of the reservoir characterized by gas cap, bottomwater or both. Infill drilling proved uneconomic with primary recovery producing only 2% OOIP and the waterflood potential is not economically viable. Additional simulations have shown that the presence of gas cap and/or bottomwater is also detrimental to any polymer flooding scheme. The results also indicated that a polymer flood can produce oil at economic rates if the bottomwater zone or gas cap are of a limited thickness in comparison to the net pay.

Conclusion

This study focused on progressing the polymer flood concept to improve oil recovery in the East Bodo Field from initial screening, to laboratory evaluations and simulations and, finally, to the field pilot stage. The results at each evaluation step reinforced the idea of the polymer flood technology to be a suitable and economical IOR process for East Bodo.

1) Using high level screening criteria showed that the polymer flood technology had greater potential than thermal, solvent or microbial EOR methods.
2) The polymer flood technology addressed the main concern of poor conformance during immiscible displacement of heavy oil (due to a poor mobility ratio). More complex chemical flooding schemes can be evaluated after the polymer technology has proved successful in the field.
3) The coreflood test indicated that the polymer flood accelerated the displacement efficiency. A half pore volume of polymer slug recovered an incremental 20% OOIP (after the core had been waterflooded with 1 pore volume and the water cut surpassed 90%).
4) Field-scale simulations indicated that a polymer pilot initiated on a pattern with vertical wells would produce oil at much lower water cuts than the existing waterflood.
5) Combined polymer flood technology with parallel horizontal wells achieved higher injectivity of the viscous polymer solution and increased oil production rates. This synergy of horizontal wells and polymer technology will be implemented in the development of new patterns (Phase 2).
6) The 11-14 pattern was chosen as the Phase 1 pilot site based on the lowest exposure to incremental capital costs and the lowest risk to jeopardize future oil production. A waterflood was already operating on this pattern.
7) Water quality issues became a major concern during the early piloting stage, mainly due to iron concentrations in the source water. These issues were sidestepped by using a fresher water source. The fresher source water allowed mixing and injection of viscous polymer solutions of 50 mPa·s or more.
8) After achieving fill-up in the pilot area and a voidage replacement ratio of 1, a dramatic increase in injection pressure was observed. The lowering of the produced water cut will be the next positive response expected from the polymer flood.
9) The pilot design focused on testing the technology on an existing vertical pattern in Phase 1. Encouraging results from Phase 1 will allow for immediate expansion to Phase 2 using horizontal wells.

Acknowledgements

The authors would like to acknowledge the support and assistance provided by Pengrowth Corporation, which made it possible to conduct and present this study.

REFERENCES

1. KNIGHT, B.L. and RHUDY, J.S., Recovery of High-Viscosity Crudes by Polymer Flooding; *Journal of Canadian Petroleum Technology, Vol. 16, No. 4, pp. 46-55, October-December 1977.*
2. WASSMUTH, F.R., GREEN, K., HODGINS, L. and TURTA, A.T., Polymer Flood Technology for Heavy Oil Recovery; *paper 2007-182 presented at the Petroleum Society's 8th Canadian International Petroleum Conference (58th Annual Technical Meeting), Calgary, AB, 12-14 June 2007.*
3. ELEMENT, D.J., GOODYEAR, S.G., SARGENT, N.C. and JAYASEKERA, A.J., Comparison of Polymer and Waterflood Residual Oil Saturations; *paper IOR-04 presented at the 11th Symposium on Improved Oil Recovery, 63rd EAGE Conference & Exhibition, Amsterdam, Netherlands, 11-12 June 2001.*
4. ZAITOUN, A., TABARY, R., FOSSEY, J.P. and BOYLE, T., Implementing a Heavy-Oil Horizontal Well Polymer Flood in Western Canada; *paper 1998.191 presented at the Seventh UNITAR International Conference on Heavy Crude and Tar Sands, Beijing, China, 27-30 October 1998.*
5. SELBY, R., ALIKHAN, A.A. and FAROUQ ALI, S.M., Potential of Non-Thermal Methods for Heavy Oil Recovery; *Journal of Canadian Petroleum Technology, Vol. 28, No. 4. pp. 45-59, July-August 1989.*

Provenance—Original Petroleum Society manuscript, **Polymer Flood Application to Improve Heavy Oil Recovery at East Bodo** (2007-184), first presented at the 8th Canadian International Petroleum Conference (the 58th Annual Technical Meeting of the Petroleum Society), June 12-14, 2007, in Calgary, Alberta. Abstract submitted for review December 15, 2006; editorial comments sent to the author(s) July 22, 2008; revised manuscript received December 9, 2008; paper approved for pre-press December 9, 2008; final approval <Approved>.

Authors' Biographies

Fred Wassmuth graduated from the University of Calgary with a Ph.D. in physical chemistry in 1990. Fred's work on chemically improved oil recovery processes started in 1991 at the Petroleum Recovery Institute, now a legacy company of the Alberta Research Council. He has been involved with traditional chemical flooding methods such as polymer, alkali/surfactant/polymer and micellar surfactant floods for recovering conventional oils. This research led to several field projects which demonstrated the commercial application of polymer flooding to improve the recovery of heavy oils in Western Canada.

Wayne Arnold graduated from the University of Alberta with a B.Sc. degree in mechanical engineering in 1983. Wayne worked as a Well Test Engineer for Halliburton Services Ltd. for the next ten years, primarily in Western Canada, but also enjoyed international assignments in Denmark, Venezuela, Nigeria, Singapore, Papua New Guinea, Colombia and on the east coast of Canada. Wayne joined PanCanadian Energy in 1995, gaining experience in operations, facility, production and exploitation engineering. In 2003, he initiated the polymer flood at Pelican Lake for EnCana. In 2004, he moved to Pengrowth Corporation, where he implemented the polymer flood work described in this paper. As Subsurface Lead, Lindbergh Oilsands, Wayne is in charge of the exploitation, production and completion engineering for Pengrowth's SAGD project.

Ken Green is a Senior Technologist for the Alberta Research Council. Ken is currently utilizing simulation programs to improve the design of polymer field applications. His work incorporates laboratory results to calibrate reservoir simulators for field-scale simulations. He has over 30 years of experience in laboratory studies for enhanced oil recovery.

Neil Cameron graduated from the University of Alberta in petroleum engineering in 2003. He started his career with Pengrowth as an Exploitation Engineer, working in Judy Creek on water and miscible flooding projects. In 2005, Neil's career path moved to conventional heavy oil as a Production and Completions Engineer, where he was responsible for all operations and commissioning of Pengrowth's first polymer flood. Currently, Neil is the Exploitation and Operations Engineer charged with the design of Pengrowth's first SAGD pilot.