

# Key Aspects of Project Design for Polymer Flooding at the Daqing Oil Field

Dongmei Wang, Exploration and Development Research Institute of Daqing Oil Field Company; R.S. Seright, New Mexico Petroleum Recovery Research Center; Zhenbo Shao and Jinmei Wang, Exploration and Development Research Institute of Daqing Oil Field Company

## Summary

This paper describes the design procedures that led to favorable incremental oil production and reduced water production during 12 years of successful polymer flooding in the Daqing oil field. Special emphasis is placed on some new design factors that were found to be important on the basis of extensive experience with polymer flooding. These factors include (1) recognizing when profile modification is needed before polymer injection and when zone isolation is of value during polymer injection, (2) establishing the optimum polymer formulations and injection rates, and (3) time-dependent variation of the molecular weight of the polymer used in the injected slugs.

For some Daqing wells, oil recovery can be enhanced by 2 to 4% of original oil in place (OOIP) with profile modification before polymer injection. For some Daqing wells with significant permeability differential between layers and no crossflow, injecting polymer solutions separately into different layers improved flow profiles, reservoir sweep efficiency, and injection rates, and it reduced the water cut in production wells. Experience over time revealed that larger polymer-bank sizes are preferred. Bank sizes grew from 240–380 mg/L·PV during the initial pilots to 640 to 700 mg/L·PV in the most recent large-scale industrial sites [pore volume (PV)]. Economics and injectivity behavior can favor changing the polymer molecular weight and polymer concentration during the course of injecting the polymer slug. Polymers with molecular weights from 12 to 35 million Daltons were designed and supplied to meet the requirements for different reservoir geological conditions. The optimum polymer-injection volume varied around 0.7 PV, depending on the water cut in the different flooding units. The average polymer concentration was designed approximately 1000 mg/L, but for an individual injection station, it could be 2000 mg/L or more. At Daqing, the injection rates should be less than 0.14–0.20 PV/year, depending on well spacing.

## Introduction

Many elements have long been recognized as important during the design of a polymer flood (Li and Niu 2002; Jewett and Schurz 1970; Sorbie 1991; Vela et al. 1976; Taber et al. 1997; Maitin 1992; Koning et al. 1988; Demin et al. 1995, 2002; Wang and Qian 2002; Wang et al. 2008). This paper spells out some of those elements, using examples from the Daqing oil field. The Daqing oil field is located in northeast China and is a large river-delta/lacustrine-facies, multilayer, heterogeneous sandstone in an inland basin. The reservoir is buried at a depth of approximately 1000 m, with a temperature of 45°C. The main formation under polymer flood (i.e., the Saertu formation) has a net thickness ranging from from 2.3 to 11.6 m with an average of 6.1 m. The average air permeability is 1.1  $\mu\text{m}^2$ , and the Dykstra-Parsons permeability coefficient averages 0.7. Oil viscosity at reservoir temperature averages approximately 9 mPa·s, and the total salinity of the formation water varies from 3000 to 7000 mg/L. The field was discovered in 1959, and a waterflood was initiated in 1960. The world's largest polymer flood was implemented at Daqing, beginning in

December 1995. By 2007, 22.3% of total production from the Daqing oil field was attributed to polymer flooding. Polymer flooding should boost the ultimate recovery for the field to more than 50% OOIP—10 to 12% OOIP more than from waterflooding. At the end of 2007, oil production from polymer flooding at the Daqing oil field was more than 11.6 million  $\text{m}^3$  (73 million bbl) per year (sustained for 6 years). The polymers used at Daqing are high-molecular-weight partially hydrolyzed polyacrylamides (HPAMs).

During design of a polymer flood, critical reservoir factors that traditionally receive consideration are the reservoir lithology, stratigraphy, important heterogeneities (such as fractures), distribution of remaining oil, well pattern, and well distance. Critical polymer properties include cost-effectiveness (e.g., cost per unit of viscosity), resistance to degradation (mechanical or shear, oxidative, thermal, microbial), tolerance of reservoir salinity and hardness, retention by rock, inaccessible pore volume, permeability dependence of performance, rheology, and compatibility with other chemicals that might be used. Issues long recognized as important for polymer-bank design include bank size (volume), polymer concentration and salinity (affecting bank viscosity and mobility), and whether (and how) to grade polymer concentrations in the chase water.

This paper describes the design procedures that led to favorable incremental oil production and reduced water production during 12 years of successful polymer flooding in the Daqing oil field.

## Zone Management Before/During Polymer Flooding

**Profile Modification Before Polymer Injection.** Under some circumstances, use of gel treatments or other types of “profile modification” methods may be of value before implementation of a polymer or chemical flood (Seright et al. 2003). If fractures cause severe channeling, gel treatments can greatly enhance reservoir sweep if applied before injection of large volumes of expensive polymer or surfactant formulations (Trantham et al. 1980). Also, if one or more high-permeability strata are watered out, there may be considerable value in applying profile-modification methods before starting the enhanced-oil-recovery (EOR) project.

For some Daqing wells with layers with no crossflow, numerical simulation demonstrated that oil recovery can be enhanced by 2–4% of OOIP with profile modification before polymer injection (Chen et al. 2004). (10–12% of OOIP was the typical EOR because of polymer flooding alone.) As expected, the benefits from profile modification decrease if it is implemented toward the middle or end of polymer injection.

On the basis of field experience with profile modification at Daqing, the following basic principles were observed.

### Wells That Are Candidates for Profile Modification.

1. The downhole pressure in injection wells during initial polymer injection is lower than the average level for injectors in the site (Yuan 2005).

2. The pressure injection index, PI, (a pressure-transient-test result) is less than the average value in the pilot site (Qiao et al. 2000). PI, is defined by

$$PI = \frac{1}{t} \int_0^t p(t) dt \quad p(t), \dots \dots \dots (1)$$

**TABLE 1—EFFECT OF SEPARATE-LAYER INJECTION**

Injection Method	Layer	$D_{znet}$ (m)	$k_{eff}$ ( $10^{-3} \mu m^2$ )	Final Water Cut (%)	Ultimate Recovery (%OOIP)
Separated	Lower	5	400	98	53.36
	Higher	5	1000	98	53.34
	Combined	10	700	98	53.35
Not Separated	Lower	5	400	94	45.33
	Higher	5	1000	99.6	57.29
	Combined	10	700	98	51.31

Total injection polymer mass: 570 mg/L·PV.  
 Polymer concentration: 1000 mg/L.

and is the well pressure after the injector is shut in for time,  $t$ , during a pressure-transient test (at Daqing, these transient tests typically last 90 minutes).

3. Injection pressures are less than the average level and the water cuts at the offset production wells are larger than the average level.

**Layers That Are Candidates for Profile Modification.**

1. Choose layers that show good lateral connectivity between wells, that have high permeability differential with respect to adjacent layers, that have high permeability and thick net pay, and that exhibit effective-permeability barriers between adjacent zones. (Here, permeability differential is defined as permeability of the high-permeability zone divided by the permeability of the low-permeability zone.)

2. Choose layers with a high water cut, a high water saturation, or that appear watered-out.

3. Choose layers with a large difference in water intake from other layers. (Water-intake index is given by injection rate divided by  $\Delta p$  times net pay of the injectors.) (Yuan 2005).

**Separate-Layer Injection.** If crossflow can occur between adjacent strata, sweep in the less-permeable zones can be almost as great as that in the high-permeability zones if the mobility ratio times the permeability differential is less than unity (Zhang and Seright 2007). However, if no crossflow occurs between strata, sweep in the less-permeable zone will be no better than approximately the square root of the reciprocal of the permeability differential (Zhang and Seright 2007). At Daqing, a means was devised to improve this sweep problem when crossflow does not occur. On the basis of theoretical studies and practical results from Daqing pilot tests (Wu et al. 2005; Wang and Qian 2002), separate-layer injection was found to improve flow profiles, reservoir-sweep efficiency, and injection rates, and it can reduce the water cut in production wells. Numerical-simulation studies reveal that the efficiency of polymer flooding depends importantly on the permeability differential between layers and at the time at which separate-layer injection occurs.

An example based on numerical simulation is provided in Table 1, in which the permeability differential was 2.5 and flooding occurred until 98% water cut was reached. In this case, the incremental recovery using layer separation was 2.04% more than the case with no layer separation. The simulations were performed with an in-house simulator called Polymer. This simulator was an improved version of the UTCHEM (University of Texas, Austin, Texas, Version 6.0, 1997), and is a 3D multiphase multicomponent compositional variable-temperature finite-difference numerical simulator. For the simulations described in Table 1, we used a 3D model that had 17x17x2 gridblocks.

Based on numerical simulation, Fig. 1 shows ultimate-recovery results for various conditions when the injection rate was held constant in different layers (i.e., the same injection rate per unit of net pay occurred in all layers). In this figure, the final polymer slug had a polymer-concentration/volume product (i.e., a polymer mass) of 600 mg/L·PV (Wu et al. 2005). The x-axis plots the delay (expressed in mg/L·PV) between the start of initial polymer injection (with no separation of injection) and when separate-layer

injection was initiated. The figure shows that separate-layer injection did not affect ultimate oil recovery if the polymer mass at the time of layer separation was less than 200 mg/L·PV. However, above this value, the total effectiveness decreased with delay of the start of separate injection. Increased vertical heterogeneity accentuated this effect.

Results from theoretical studies and from practical pilot tests indicate that separate-layer injection should be implemented before the polymer-concentration/volume product (mass) becomes 200 mg/L·PV if this technology can be implemented in the sites (Zhang et al. 2004). For those wells where injection cannot be separated because of technical or other reasons, flow profiles should be controlled as well as is practical, and separate-layer injection should be implemented when it becomes feasible.

Our theoretical studies and pilot tests revealed that the conditions that favor separate-layer injection at Daqing include (Wu et al. 2005)

1. The permeability differential between oil zones  $\geq 2.5$ .

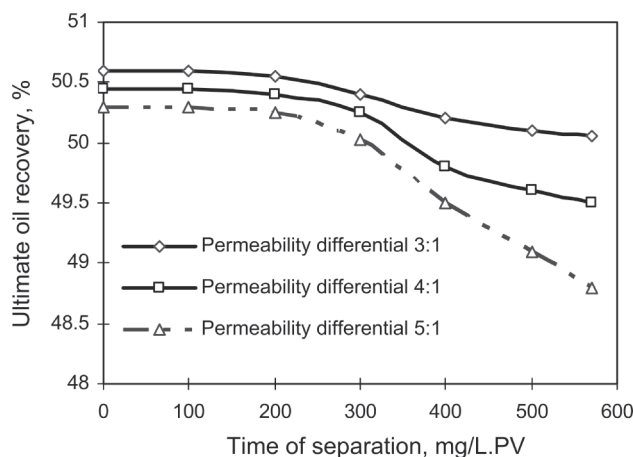
2. The net pay for the lower-permeability oil zones should account for at least 30% of the total net pay.

3. Layers should be separated by a barrier that is at least 1 m thick.

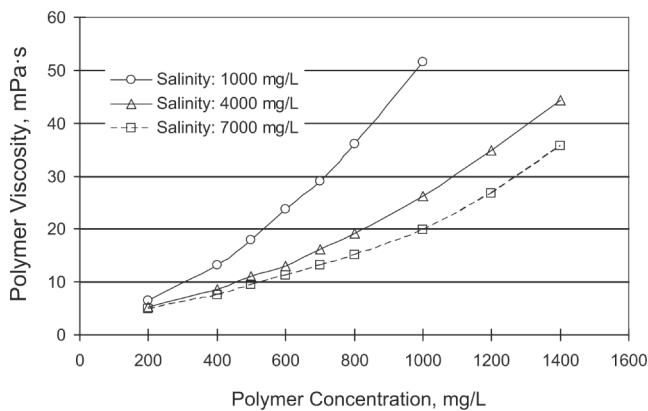
**Optimization of the Polymer-Injection Formula**

Important factors to optimize when formulating the polymer bank include polymer-solution viscosity, polymer molecular weight, polymer concentration, polymer volume, and injection rate.

**Polymer-Solution Viscosity.** The polymer-solution viscosity is a key parameter to improve the mobility ratio between oil and water and to adjust the water-intake profile. As injection viscosity increases, the effectiveness of polymer flooding increases. The viscosity can be affected by a number of factors. First, for a given set of conditions, solution viscosity increases with increased polymer



**Fig. 1—Effect on ultimate recovery of time at which separate-layer injection is initiated. Constant total rate.**



**Fig. 2—Viscosity vs. concentration for different salinities with medium- $M_w$  (15 million Daltons) polymer (Wang et al. 2001).**

molecular weight. Second, increased polymer concentration leads to higher viscosity and increased sweep efficiency. Third, as the degree of HPAM-polymer hydrolysis increases up to a certain value, viscosity increases. Fourth, as temperature increases, solution viscosity decreases. Polymer degradation can also decrease viscosity. Fifth, increased salinity and hardness in the reservoir water also decreases solution viscosity for anionic polymers.

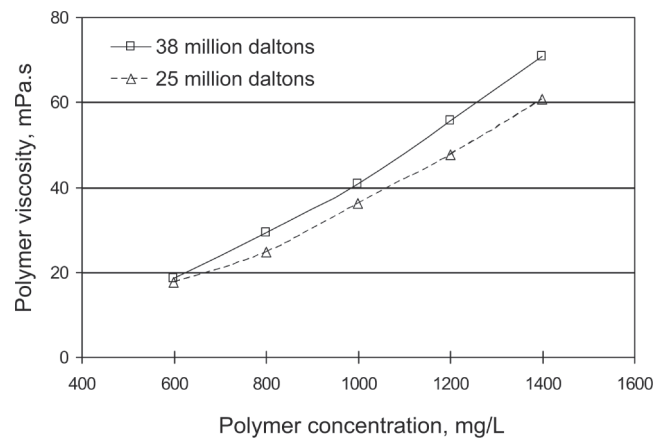
The effectiveness of a polymer flood is determined directly by the magnitude of the polymer viscosity. The viscosity depends on the quality of the water used for dilution. A change in water quality directly affects the polymer solution viscosity. At Daqing, the water quantity changes with the rainfall, ground temperature, and humidity during the seasons. The concentrations of  $Ca^{2+}$  and  $Mg^{2+}$  in the water source are lower in summer and higher in winter. Consequently, the polymer viscosity is also relatively higher in summer and lower in winter.

Using a medium- $M_w$  HPAM polymer, the injection polymer concentration and solution viscosity can be adjusted according to Fig. 2. These curves were used during project design for the pilot site in the center of Saertu at Daqing. The curves were invaluable in adjusting polymer concentrations to respond to changes in water quality (salinity). In this application, for a medium- $M_w$  polymer (12 to 16 million Daltons), 40 mPa·s was recommended. This viscosity level was sufficient to overcome (1) the unfavorable mobility ratio (i.e., 9.4) and (2) permeability differential up to 4:1.

For a high- $M_w$  polymer (17 to 25 million Daltons) or extrahigh- $M_w$  polymer (25 to 38 million Daltons), 50-mPa·s viscosity could be provided cost-effectively. For new polymers that provide special fluid properties, additional laboratory investigations are needed before implementation in a polymer flood.

**Polymer Molecular Weight.** The effectiveness of a polymer flood is affected significantly by the polymer  $M_w$ . As illustrated in Fig. 3, polymers with higher  $M_w$  provide greater viscosity. For many circumstances, larger polymer  $M_w$  also leads to improved oil recovery. Results from numerical simulation of corefloods (Table 2) verify this expectation for cases of constant polymer-slug volume and concentration.

Our laboratory tests with a fixed volume of polymer solution injected confirmed that oil recovery increases with increased poly-



**Fig. 3—Viscosity vs. concentration and vs.  $M_w$  for polymers used in the central part of Xing4-5 (Gao and Su 2004).**

mer  $M_w$  (Wu et al. 2001). The reason is simply that for a given polymer concentration, solution viscosity and sweep efficiency increase with increased polymer  $M_w$ . Stated another way, to recover a given volume of oil, less polymer is needed using a high- $M_w$  polymer than with a low- $M_w$  polymer.

The above argument must be tempered because the levels of mobility and permeability reduction (i.e., the resistance factor and residual resistance factor) for polymer with a given  $M_w$  can increase with decreasing permeability (Vela et al. 1976). (Resistance factor,  $F_r$ , is defined as brine mobility divided by polymer-solution mobility. Residual resistance factor,  $F_{rr}$ , is defined as brine mobility before polymer flooding divided by brine mobility after polymer flooding.) This effect is accentuated as  $M_w$  increases. Mechanical entrapment can retard polymer propagation significantly if the pore-throat size and permeability are too small. Thus, depending on  $M_w$  and permeability differential, this effect can reduce sweep efficiency (Zhang and Seright 2007). A trade-off must be made in choosing the highest- $M_w$  polymer that will not exhibit pore plugging or significant mechanical entrapment in the less-permeable zones.

Two factors should be considered when choosing the polymer  $M_w$ . First, choose the polymer with the highest  $M_w$  practical to minimize the polymer volume. Second, the  $M_w$  must be small enough so that the polymer can enter the reservoir rock and propagate effectively through it. For a given rock permeability and pore-throat size, a threshold  $M_w$  exists, above which polymers exhibit difficulty in propagation.

On the basis of laboratory results and practical experience at Daqing, the medium polymer  $M_w$  (12 to 16 million Daltons) is applicable for oil zones with average permeability greater than  $0.1 \mu m^2$  and net pay greater than 1 m. The high polymer  $M_w$  (17 to 25 million Daltons) is appropriate for oil zones with average permeability greater than  $0.4 \mu m^2$ . Table 3 shows recovery results for various combinations of polymer  $M_w$  and core permeability. Table 4 lists  $F_r$  and  $F_{rr}$  for different combinations of polymer  $M_w$  and core permeability.

Economics and injectivity behavior can favor changing the polymer  $M_w$  during the course of injecting the polymer slug. This point can be appreciated from Table 5, which considers six cases where a bank of high- $M_w$  (17.9 million Daltons) HPAM polymer was injected before switching to a bank of medium- $M_w$  (12 million Daltons) HPAM polymer. In this simulation example, the total polymer concentration (1000 mg/L) and bank size (570 mg/L·PV) were held constant. The left-hand column of Table 5 lists the percentage of the total bank that involved injection of the high- $M_w$  polymer, while the middle column lists the total EOR from the polymer flood. The right-hand column lists the incremental EOR, compared with using only the medium- $M_w$  polymer.

Details of the numerical-simulation model can be found in Shao et al. 2001. In this simulator, polymer retention is modeled both by adsorption and by mechanical entrapment—varying with

**TABLE 2—EFFECT OF POLYMER  $M_w$  ON EOR**

$M_w$ ( $10^6$ Daltons)	Waterflood Recovery (%)	Polymer-Flood EOR (%)	Ultimate Recovery (%)
5.5	32.7	10.6	43.3
11	32.9	17.9	51.8
18.6	32.2	22.6	54.8

Total injected polymer mass: 570 mg/L·PV.  
 Polymer concentration: 1000 mg/L, 3 zones.  
 Heterogeneity:  $V_r=0.72$ .



**TABLE 3—EFFECTIVENESS FOR DIFFERENT  $M_w$  AND  $k_{water}$**

$k_{water}$ ( $10^{-3} \mu m^2$ )	Waterflood Recovery (%OOIP)	Ultimate Recovery (%OOIP)	Polymer EOR (%OOIP)	$M_w$ ( $10^6$ Daltons)
330.3	50.46	72.48	22.02*	38
333.3	50.00	68.86	18.86	25
364.3	59.26	67.38	8.12	—
456.8	58.89	67.54	8.65	15
327.0	61.29	68.85	7.56	—
96.9	56.73	63.63	6.90	8
85.85	57.87	64.61	6.74	—
46.9	44.25	48.62	4.37	5.5
51.96	48.44	52.96	4.52	—
9.11	43.21	46.91	3.70	2.4
16.63	41.39	45.26	3.87	—

\* Polymer mass = 500 mg/L·PV for this case. Polymer mass = 570 mg/L·PV for the other cases.

permeability, salinity, and polymer concentration. Polymer solutions are allowed to reduce both the mobility of displacing fluid (i.e., resistance factor) and the effective permeability of the porous medium (i.e., residual resistance factor). Polymer-solution viscosity depends on the salinity and polymer concentration (Sun et al. 1989). Both shear thinning and viscoelastic polymer rheology are built into the model's polymer properties. Furthermore, our model includes a viscoelastic polymer property that acts to reduce residual-oil saturation below the value expected from waterflooding or conventional polymer flooding.

In Table 5, the EOR from injection of only the higher- $M_w$  polymer was 3.0% of OOIP greater than that from injection of only the medium- $M_w$  polymer (12 million Daltons). Most of the benefit (i.e., 2%) was achieved if only 20% of the bank had the high- $M_w$  polymer. Increasing the high- $M_w$ -polymer fraction in the bank provided little additional increase in oil recovery. If injectivity is lower and cost is higher for the high- $M_w$  polymer than for the lower- $M_w$  polymer, a significant benefit can be achieved by changing (i.e., decreasing) the polymer  $M_w$  during injection of the polymer slug. For the particular example here, the high- $M_w$  polymer costs 1.1 to 1.3 times more than the medium- $M_w$  polymer. For the same polymer concentration, injectivity for the high- $M_w$  polymer was 70% of that for the medium- $M_w$  polymer. Given approximately the same incremental oil recovery, greater injectivity, and lower polymer cost leads to accelerated oil recovery and greater net present value for the project.

**Polymer-Solution Concentration.** Polymer-solution concentration determines the polymer-solution viscosity and the size of the required polymer-solution slug. The polymer-solution concentration dominates every index that changes during the course of polymer flooding.

1. Higher injection concentrations cause greater reductions in water cut and can shorten the time required for polymer flooding. For a certain range, they can also lead to an earlier response time in the production wells, a faster decrease in water cut, a greater decrease in water cut, less required PV of polymer, and less required volume of water injected during the overall period of polymer flooding. On the basis of numerical simulation, **Table 6** shows the effectiveness of polymer flooding as a function of polymer

concentration when the injected-polymer mass is 640 mg/L·PV. As polymer concentration increases, EOR increases and the minimum in water cut during polymer flooding decreases.

2. Above a certain value, the injected-polymer concentration has little effect on the efficiency of polymer flooding. For a pilot project, the economics of injecting higher polymer concentrations should be considered. The polymer-solution concentration has a large effect on the change in water cut. However, consideration should also be given to the fact that higher concentrations will cause higher injection pressures and lower injectivity. Considering the technical feasibility and conditions at Daqing, the average injection polymer concentration ranges from 1000 to 1400 mg/L for our projects. For individual wells, the concentration can be adjusted to meet particular conditions.

3. Additional steps can increase effectiveness when using slugs with higher polymer concentrations. First, effectiveness can be improved by injecting polymer solutions with higher concentrations during the initial period of polymer flooding. The increase in effectiveness comes from the wells or the units that experienced in-depth vertical-sweep improvement during the early stages of polymer flooding. Second, the increase in water cut during the third stage of polymer flooding (i.e., after the minimum in water cut) can be controlled effectively using injection of higher polymer concentrations. On the basis of pilot tests in two areas of the Daqing field (the "Western of Central" area and the "1-4# Station in the Beixi of Lamadian" area), the water-intake profile became much more uniform after injecting 2200- to 2500-mg/L polymer solution in 2004 (Fulin et al. 2004; Yang et al. 2004).

Polymer retention also plays an important role in determining the appropriate polymer concentration. Sufficient polymer must be injected to allow the polymer to propagate most of the way through the reservoir. Laboratory measurements using Daqing core material revealed retention values of 126  $\mu g/g$  for a 15-million-Dalton HPAM and 155  $\mu g/g$  for a 25-million-Dalton HPAM. Calculations suggest that injection of 1 PV of 1000-mg/L polymer solution would experience 65% depletion by retention for the 15-million-Dalton polymer and 80% depletion for the 25-million-Dalton polymer. Polymer-bank sizes at Daqing are designed for effective propagation using these polymer-retention levels. The actual viscosities of the polymer solutions that flow in the formation and that are produced from the formation have been measured. Flowing polymer solutions within the formation typically have a viscosity of approximately 20 cp. Mechanical degradation of the polymer is believed to be the primary cause of viscosity loss from the surface (where the originally injected polymer typically has a viscosity of approximately 40 cp) to locations deep within the reservoir (Wang et al. 2008; Seright 1983).

**Polymer Volume.** Oil-recovery efficiency decreases with increased mobility of the injectant (Jang 1994; Craig 1991). A con-

**TABLE 4— $F_r$  and  $F_{rr}$  FOR DIFFERENT  $k_{air}$  AND  $M_w$**

$M_w$ ( $10^6$ Daltons)	$k_{air}$ ( $10^{-3} \mu m^2$ )	$F_r$	$F_{rr}$
15	498	8.5	3.2
—	235	10.1	4.1
25–30	1000	27	4.7
38	1500	53	3.6

**TABLE 5—INJECTING 17.9 MILLION DALTONS OF POLYMER BEFORE 12 MILLION DALTONS OF POLYMER\***

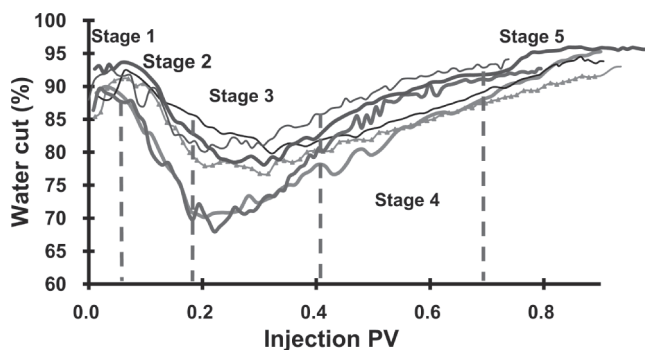
High- $M_w$ Proportion (%)	EOR (%OOIP)	Incremental EOR (%OOIP)
0	20.7	0
10	21.6	0.9
20	22.7	2.0
33	23.6	2.9
50	23.6	2.0
100	23.7	3.0

\* Li and Niu 2002.  
Total injection polymer mass: 570 mg/L·PV. Polymer concentration: 1000 mg/L, 3 zones. Heterogeneity:  $V_k=0.72$ .

**TABLE 6—ULTIMATE RECOVERY AND EOR VS. POLYMER CONCENTRATION**

Polymer (mg/L)	Minimum Water Cut (%)	Ultimate Recovery (%OOIP)	EOR (%OOIP)
600	87.1	50.58	7.69
800	85.0	52.52	9.64
1000	83.1	52.83	9.95
1200	82.4	52.89	10.01
1500	81.0	53.03	10.15

\* Values noted at polymer mass = 640 mg/L·PV.



**Fig. 4—Five stages of water cuts during a polymer flood.**

tinuous polymer flood could be used instead of a waterflood. However, because polymer solutions are more expensive than water, economics limit the volume of polymer that should be injected.

For the first polymer pilot tests at Daqing, the polymer-volume/concentration product (mass) was designed to be 240 to 380 mg/L·PV. Later, the polymer mass was increased to 570 mg/L·PV. At present, the polymer mass is 640 to 700 mg/L·PV in the large-scale industrial sites.

On the basis of our theoretical research and practical experiences, the polymer volume should be determined by the gross water cut of the flooding unit. Generally, when the gross water cut reaches 92–94%, the polymer injection should be stopped.

On the basis of statistics from the 1–4# Station of the eastern Lamadian area of the Daqing oil field, the rate of increase in the water cut is approximately the same during the last part of the polymer flood as it is during the follow-up waterdrive. Generally at Daqing, polymer injection is switched to waterdrive when the water cut reaches 92 to 94%. On the basis of our observations of the response to polymer flooding, we characterize the entire polymer-flooding process in five stages, as illustrated in **Fig. 4** (Guo et al. 2002; Liao et al. 2004) and described in the following:

1. The initial stage of the polymer flood in which water cut has not yet started to decrease. This stage ranges from the very beginning of polymer injection typically to 0.05 PV. During this time, the polymer solution has not begun to work.

2. The response stage in which a decrease in water cut can be seen. At Daqing, this stage typically occurs from 0.05 to 0.20 PV of polymer injection. During this time, the polymer solution penetrates deep into the formation and forms the oil bank. Typically, approximately 15% of the EOR is produced during this stage.

3. The period in which the water cut change is relatively stable. The minimum water cut was observed during this period. This stage typically lasts from 0.20 to 0.40 PV of polymer injection. The oil-production rate reaches its peak value, and approximately 40% to the total EOR is produced during this stage. Oil production begins to decrease, and the produced-polymer concentration begins to increase.

4. The stage in which water cut increases again rapidly. This stage typically lasts from 0.40 to 0.70 PV of polymer injection. Areal sweep reaches its maximum; oil production declines, the polymer concentration and the injection pressure follow steady trends. Approximately 30% of the total EOR is produced during this stage.

5. The stage of the follow-up waterdrive. This stage lasts from the end of polymer injection to the point at which water cut reaches 98%. Water cut increases continuously; the produced-polymer concentration declines rapidly; and the fluid-production capability increases a little. The EOR produced during this stage is approximately 10–12% of the total.

On the basis of numerical simulation, ultimate oil recovery becomes less sensitive to bank size as the polymer mass increases to high values. Of course, increased polymer mass enhances the oil recovery (middle column of **Table 7**). However, the incremental polymer efficiency (defined in the right-hand column of **Table 7**) decreases with increased polymer mass. Consequently, there is an economic optimum in the polymer-bank size.

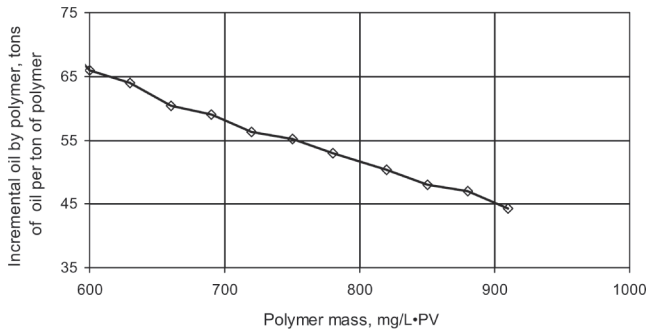
For large polymer banks, polymer was produced from wells after the water cut increased back up to 92%. So, more extended injection of polymer hurts income and economics because the produced polymer is effectively wasted.

**Fig. 5** plots the incremental oil (expressed per ton of polymer injected). On the basis of our economic evaluation, optimum effectiveness can be obtained if a suitable time to end polymer injection is chosen, followed by a water-injection stage. For Daqing, the optimum polymer mass ranged from 640 to 700 mg/L·PV. Projects at Daqing were profitable within this range, for the oil prices experienced over the past 12 years.

**TABLE 7—INCREMENTAL RECOVERY VS. POLYMER MASS\***

Polymer Mass (mg/L·PV)	Ultimate Recovery (%)	Incremental Polymer Efficiency [%OOIP / (mg/L·PV)]
570	50.74	—
665	51.24	0.0147
760	53.26	0.0118
855	54.28	0.0107
950	55.10	0.0086

\* Wu et al. 2005.

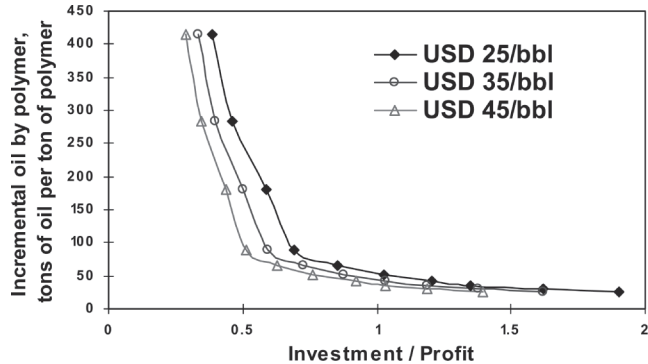


**Fig. 5—Incremental oil vs. polymer mass (Shao et al. 2005).**

Numerical simulation and our economic evaluation revealed that when income from the polymer project matched the investment (i.e., the “break-even point”), the incremental oil was 55 metric tons of oil per metric ton of polymer (64 m<sup>3</sup> of oil per m<sup>3</sup> of polymer) [when the oil price was 1280 Chinese Yuan per m<sup>3</sup> or approximately USD 25.5/bbl, and the polymer mass was 750 mg/L·PV (See Fig. 5)]. Of course, the optimum polymer mass depends on oil price. The break-even point is reduced to 36 metric tons of oil per ton of polymer (42 m<sup>3</sup> of oil per m<sup>3</sup> of polymer) when the oil price increases to USD 45/bbl (see Fig. 6). With the current high oil prices, greater polymer masses could be attractive.

**Injection Rate.** The polymer-solution injection rate is another key factor in the project design. It determines the oil-production rates. Table 8 shows the effect of injection rate on the effectiveness of polymer flooding. It shows that the magnitude of the injection rate has little effect on the final recovery. It also has a minor effect on the fraction of the injected polymer mass that is ultimately produced (fourth column from left of Table 8). However, the injection rate has a significant effect on the cumulative production time. Lower injection rates lead to longer production times. So when we program the design, the injection rate should not be too small.

Fig. 7 shows how reservoir pressure changes with the injection rate after the completion of polymer injection. As expected, the average reservoir pressure near the injectors increases as the injection rate increases while decreasing near production wells.



**Fig. 6—Incremental oil vs. investment/profit ratio (Shao et al. 2005).**

Also, higher injection rates cause a larger disparity between injection and production. Injection rates must be controlled (i.e., not too high) to minimize polymer flow out of the pattern or out of the target zones.

Changes in the behavior of gross water cut with time also depend on the injection rate (Fig. 8). Lower injection rates lead to slower increases in water cut and delay the time when lowest water cut begins to increase. As a result, the stable period with lower water cut is extended. If Fig. 8 were replotted with PV on the x-axis, the curves would coincide. In western nations, economics might favor accelerating injection and production to the maximum allowable extent. However, in China, this tendency is moderated by a need for sustainable development of the oil field, so that a more protracted oil production becomes optimum. In addition, early polymer breakthrough becomes a greater risk for higher injection rates (which would significantly, and undesirably, alter the shape of a given curve in Fig. 8).

The injection rate determines the time period when oil can be recovered economically. Fig. 9 shows how injection rates affect the oil-production rate. It also demonstrates how the term of economic production varies with injection rate. To maximize the term of oil production and maximize ultimate production, the injection rate at Daqing should be maintained under 0.16 PV/yr with 250-m well spacing.

**TABLE 8—EFFECT OF INJECTION RATE ON POLYMER FLOODING**

Injection Rate (PV/yr)	Ultimate Recovery (%OOIP)	EOR (%OOIP)	Polymer Production/Injection (%)	Production Time (years)	Injected PV
0.08	51.51	12.32	48.36	9.54	0.763
0.10	51.36	12.17	48.46	7.62	0.762
0.12	51.22	12.03	48.57	6.34	0.761
0.14	51.07	11.88	48.68	5.43	0.760
0.16	50.94	11.78	48.81	4.75	0.760
0.18	50.81	11.62	48.93	4.22	0.760
0.20	50.68	11.49	49.06	3.79	0.758

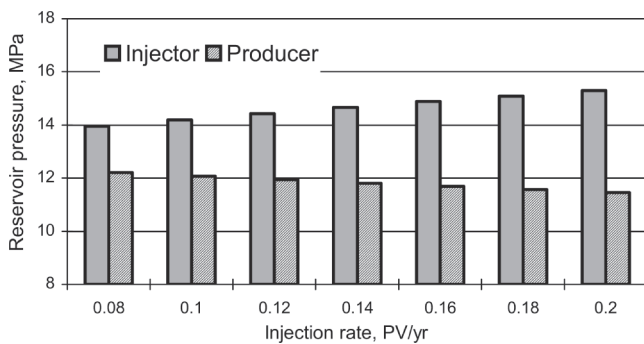


Fig. 7—Injection rate vs. reservoir pressure.

In summary, the injection rate affects the whole development and effectiveness of polymer flooding. Eq. 2 can be used to relate the highest pressure at the injection wellhead and the average individual injection rate with the polymer-injection rate and the average apparent-water-intake index for different reservoir conditions. In general, the injection rate should not exceed the reservoir-fracture pressure.

$$p_{\max} = l^2 \phi q (180 N_{\min}), \dots \dots \dots (2)$$

where  $p_{\max}$  is highest wellhead pressure, MPa;  $l$  is the distance between injector and producer, m;  $\phi$  is porosity, %;  $N_{\min}$  is lowest apparent-water-intake index,  $\text{m}^3/(\text{d}\cdot\text{m}\cdot\text{MPa})$ ; and  $q$  is injection rate, PV/year.

For the best results at Daqing, the polymer-injection rate should be designed to be 0.14 to 0.16 PV/yr for 250-m well spacing, and to be 0.16 to 0.20 PV/yr for 150- to 175-m well spacing.

### Conclusions

On the basis of more than 12 years of experience at the Daqing oil field, we identified key aspects of project design for polymer flooding.

1. For some Daqing wells, oil recovery can be enhanced 2 to 4% of OOIP with profile modification before polymer injection.
2. For some Daqing wells with significant permeability differential between layers and no crossflow, injecting polymer solutions separately into different layers improved flow profiles, reservoir-sweep efficiency, and injection rates, and it reduced the water cut in production wells.
3. Experience over time revealed that larger polymer-bank sizes are preferred. Bank sizes grew from 240 to 380 mg/L·PV during the initial pilots to 640 to 700 mg/L·PV in the most recent large-scale industrial sites.
4. Economics and injectivity behavior can favor changing the polymer molecular weight and polymer concentration during the course of injecting the polymer slug. Polymers with molecular

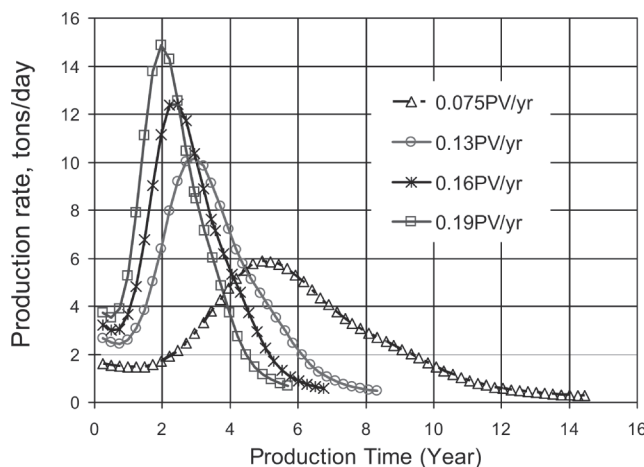


Fig. 9—Changes in oil-production rate vs. injection rate.

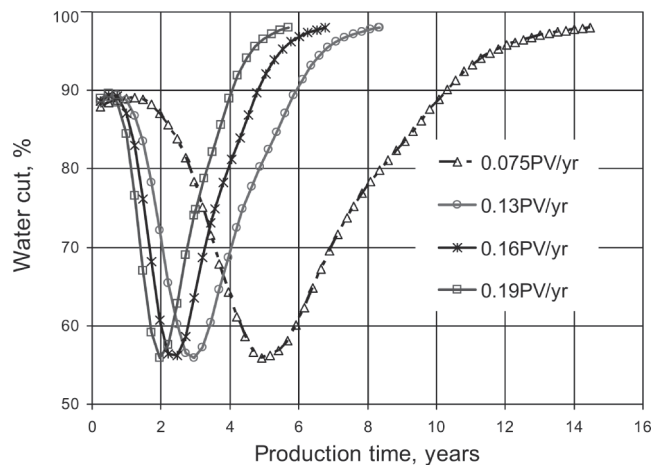


Fig. 8—Water cut changes for different injection rates.

weights from 12 to 38 million Daltons were designed and supplied to meet the requirements for different reservoir geological conditions. The optimum polymer-injection volume varied around 0.7 PV, depending on the water cut in the different flooding units. The average polymer concentration was designed to be approximately 1000 mg/L, but for an individual injection station, it could be 2000 mg/L or more.

5. At Daqing, the injection rates should be less than 0.14–0.20 PV/yr, depending on well spacing.

### Nomenclature

- $D_{\text{znet}}$  = net zone height, m
- $F_r$  = resistance factor
- $F_{rr}$  = residual resistance factor (permeability before/after polymer placement)
- $k_{\text{air}}$  = permeability to air,  $\mu\text{m}^2$
- $k_{\text{eff}}$  = effective permeability,  $\mu\text{m}^2$
- $k_{\text{water}}$  = permeability to water,  $\mu\text{m}^2$
- $l$  = distance between injector and producer, m
- $M_w$  = molecular weight, Daltons
- $N_{\min}$  = lowest apparent-water-intake index,  $\text{m}^3/(\text{d}\cdot\text{m}\cdot\text{MPa})$
- $p$  = pressure, MPa
- $p_{\max}$  = highest wellhead pressure, MPa
- $PI$  = pressure index for an injector, MPa
- $PV$  = pore volumes
- $q$  = injection rate, PV/yr
- $t$  = time, minutes
- $V_k$  = Dykstra-Parsons coefficient of permeability variation
- $\Delta p$  = pressure difference from wellbore to formation, MPa
- $\phi$  = porosity

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### SI Metric Conversion Factors

bbl × 1.589	E-01 = m <sup>3</sup>
cp × 1.0*	E-03 = Pa·s
ft × 3.048*	E-01 = m
in. × 2.54*	E+00 = cm
md × 9.869 233	E-04 = μm <sup>2</sup>
psi × 6.894 757	E+00 = kPa

\*Conversion factor is exact.

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**Dongmei Wang** is Department Chief Engineer and Senior Reservoir Engineer at the Exploration and Development Institute of the Daqing Oilfield Company in Daqing, China, where she has worked since 1987. E-mail: wangdongmei1@petrochina.com.cn. She holds a PhD degree in oil and gas development engineering from the Research Institute of Petroleum Exploration and Development at Beijing. **Randy Seright** is a senior engineer at the New Mexico Petroleum Recovery Research Center at New Mexico Tech in Socorro, New Mexico, where he has worked since 1987. E-mail: randy@prcc.nmt.edu. He holds a PhD degree in chemical engineering from the University of Wisconsin at Madison. **Zhenbo Shao** is Department Director and a senior reservoir engineer at the Exploration and Development Institute of the Daqing Oilfield Company, where he has worked since 1983. E-mail: shaozhenbo@petrochina.com.cn. He holds a masters degree in oil and gas development engineering from the China University of Petroleum at Beijing. **Jinmei Wang** is a senior engineer at the Exploration and Development Institute of the Daqing Oilfield Company. E-mail: wangjinmei@petrochina.com.cn.