FIDDLER CREEK POLYMER AUGMENTATION PROJECT

Final Report

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ABSTRACT

The Fiddler Creek field is in Weston County, Wyoming, and was discovered in 1948. Secondary waterflooding recovery was started in 1955 and terminated in the mid-1980s with a fieldwide recovery of approximately 40%. The West Fiddler Creek Unit, the focus of this project, had a lower recovery and therefore has the most remaining oil. Before the project this unit was producing approximately 85 bbl of oil per day from 20 pumping wells and 17 swab wells.

The recovery process planned for this project involved adapting two independent processes, the injection of polymer as a channel blocker or as a deep-penetrating permeability modifier, and the stabilization of clays and reduction of the residual oil saturation in the near-wellbore area around the injection wells. Clay stabilization was not conducted because long-term fresh water injection had not severely reduced the injectivity. It was determined that future polymer injection would not be affected by the clay.

For the project, two adjoining project patterns were selected on the basis of prior reservoir studies and current well availability and production. The primary injection well of Pattern 1 was treated with a small batch of MARCIT gel to create channel blocking. The long-term test was designed for three phases: (1) 77 days of injection of a 300-mg/l cationic polyacrylamide, (2) 15 days of injection of a 300-mg/l anionic polymer to ensure injectivity of the polymer, and (3) 369 days of injection of the 300-mg/l anionic polymer and a 30:1 mix of the crosslinker. Phases 1 and 2 were conducted as planned. Phase 3 was started in late March 1999 and terminated in May 2001. In this phase, a crosslinker was added with the anionic polymer. Total injection for Phase 3 was 709,064 bbl. To maintain the desired injection rate, the injection pressure was slowly increased from 1,400 psig to 2,100 psig.

Early in the application of the polymer, it appeared that the sweep improvement program was having a positive effect on Pattern 1 with lesser effects in Pattern 2. These early observations did not continue to develop. The oil production for both patterns remained fairly constant to the rates established by the restart of waterflooding. The water production declined but stabilized in both patterns. The stabilization of the oil at prepolymer rates and water production at the lower rates can be attributed to the polymer injection, but the effect was not as great as originally predicted. The sweep improvement for the patterns appeared to be negatively impacted by extended shutdowns in the injection and production systems. Such problems as those experienced in this project can be expected when long-term polymer injection is started in old waterflood fields. To prevent these problems, new injection and production tubulars and pumps would be required at a cost prohibitive to the present, independent operators.
Unless the future results from the continued waterflood show positive effects of the long-term polymer injection, it appears that the batch-type polymer treatment may have more promise than the long-term treatment and should be more cost effective.
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EXECUTIVE SUMMARY

The Fiddler Creek field is in Weston County, Wyoming, and the primary producing formation is the Newcastle (Muddy) Sand. Since discovery in 1948, 217 wells have been drilled in the field. Only a few of the wells are still producing. The original oil in place has been estimated at 65.3 MMbbl of light (40 °API), sweet crude. The combined primary and secondary waterflooding recovery, started in 1955, for the entire Fiddler Creek field was approximately 40%. This project concentrates on the West Fiddler Creek Unit (WFCU), which has the most remaining oil. Before the project was initiated, WFCU was producing approximately 85 bbl of oil per day from 20 pumping wells and 17 swab wells. At these rates, the field was reaching its economic breakpoint.

The recovery process planned for this project involved adapting two independent processes that have been used with relative success in similar petroleum reservoirs. The project was undertaken to augment the reinitiated, scaled-down, unit-wide waterflood. The first process was the injection of the polymer as a channel blocker or as a deep-penetrating permeability modifier. The purpose of this was to produce greater water entry into the low-permeability zones where the majority of the residual oil is thought to reside. The second process was stabilization of the clays and reduction of the residual oil saturation in the near-wellbore area around the injection wells. This step was to improve the water relative permeability and produce a wider water injection interval. Clay stabilization was not conducted because long-term fresh water injection had not severely reduced the injectivity. It was determined that future polymer injection would not be affected by the clay.

Two adjoining project patterns were selected on the basis of prior reservoir studies and current well availability and production. Wells in the test areas were checked for integrity and, where practical, production wells were put on a rod pumping system.

The primary injection well of Pattern 1, W40, was treated with 53 bbl of 1,500-mg/l MARCIT gel to create channel blocking. This treatment, though small in scale, produced positive results. One month after the channel-blocking treatment of W40, the long-term, deep-penetrating polymer injection was initiated into both pattern areas. The long-term test was designed for three phases: (1) 77 days of injection of a 300-mg/l cationic polyacrylamide, (2) 15 days of injection of a 300-mg/l anionic polymer to ensure injectivity of the polymer, and (3) 369 days of injection of the 300-mg/l anionic polymer and a 30:1 mix of the crosslinker. During the first phase, 14,500 lb of CAT-AN® 260 was injected at an average concentration of 344 mg/l. During Phase 2, 300 mg/l of anionic polymer was injected for 15 days. Phase 3 was started in late March 1999 and terminated in May 2001. In this phase, a crosslinker was added with the anionic polymer. Total injection for Phase 3 was 709,064 bbl. Pattern 1 accounted for 42.4% of the injection with the remaining 57.6% going to Pattern 2. To maintain the desired injection rate, the injection pressure was slowly increased from 1,400 psig to 2,100 psig.
Early in the application of the polymer, it appeared that the sweep improvement program was having a positive effect on Pattern 1 with lesser effects in Pattern 2. These early observations did not continue to develop. The oil production for both patterns remained fairly constant to the rates established by the restart of waterflooding when the number of active, producing wells was taken into account. Water production declined but stabilized in both patterns. The stabilization of the oil at prepolymer rates and water production at the lower rates can be attributed to the polymer injection, but the effect was not as great as originally predicted.

The sweep improvement for the patterns was negatively impacted by extended shutdowns in the injection and production systems. The shutdowns may account for the less-than-anticipated results or may have just retarded the enhancement. Continued waterflooding by the operator will answer the retardation issue.

The problems experienced in this project are those that can be expected when long-term polymer injection is started in old waterflood fields. In these fields, the injection piping and producing wells have seen the wear and tear of years of service or dormancy. To prevent these problems, new injection and production tubulars and pumps would be required at a cost prohibitive to the present, independent operators.

The application of long-term polymer injection to these older waterflooded fields may be questionable. But the application of a short-term (days not years) batch treatment with a high-strength, channel-blocking polymer appears to have promise. Unless the future results from the continued waterflood show positive effects of the long-term polymer injection, it appears that the batch-type polymer treatment is as effective and more cost effective than the long-term treatment.
INTRODUCTION

This project was proposed to develop and test an economical, enhanced, oil-recovery process for a previously abandoned, waterflooded reservoir. The Fiddler Creek field in Weston County, Wyoming, produces from the Newcastle (Muddy) Sand, a brown-to-white sandstone with interspersed layers of gray shale. The Newcastle Sand lies at a depth ranging from 4,500 ft on the east to 6,200 ft on the west. The OOIP is estimated to be 65.3 MMbbl of light (40 °API), sweet crude. The viscosity of the crude at the bubblepoint of 1,130 psi is 0.75 cP.

Fiddler Creek is a fluvial-dominated, deltaic reservoir. This type of reservoir is the most common and important in the United States, responsible for the majority of oil production from sandstone reservoirs. Generally, these reservoirs have coarser sediments at the base and progressively finer materials toward the top of the formation, with the reservoir bodies being thinner toward the channel mouth. This type of depositional environment results in large variations in permeability and poor lateral continuity. Thus, oil recovery for these reservoirs is usually low.

The proposed process was a polymer-augmented waterflood to be conducted in conjunction with a near-wellbore treatment to stabilize clays. If the process proves economically attractive in the Fiddler Creek field, it will be immediately applicable to other reservoirs in the vicinity. Examples of nearby fields producing from the Newcastle (Muddy) Sand are the Osage field, just to the east of Fiddler Creek; Skull Creek, Mush Creek, Clareton, Black Thunder, Cheyenne River, Sherwin, and Frog Creek fields to the south; and Hay Creek, Lonetree Creek, Lodgepole Creek, Quest, and Hay Creek fields to the west.

These fields have produced approximately 100 MMbbl of 37 to 43 °API sweet crude since the mid-1940s when development of this trend began. Waterfloods have been tested in most of these fields. Like the Fiddler Creek field, most of these fields have been sold by the major producers to independent producers and are nearing abandonment because of high water cuts and fluctuating oil prices. The independent producer generally does not have the technical staff to design and implement the type of project undertaken by Western Research Institute (WRI) and Underwood Oil and Gas.

There is also a series of large, Muddy reservoirs in the central Powder River Basin, at least some of which are arguably of fluvial-dominated, deltaic, depositional origin. These include the Hilight, Kitty, Gas Draw, Oedokoven, Recluse, and Ute fields. The combined process being used in this project is likely to be applicable to at least some of these fields as an alternative to more expensive tertiary recovery options.

The Fiddler Creek field is divided into two operating units, the East Fiddler Creek Unit (EFCU) and West Fiddler Creek Unit (WFCU). Within the west portion of the field, the Newcastle Sand averages 8 ft thick, with a producing thickness ranging from one to 14 ft. The average porosity
is 23.7% within a range of 4.7 to 28.9%. The average permeability is 126 md within a range of 0.01 to 240 md. The lateral facies changes between the sands and the shales produce some lenticular features and discontinuity in the field. The oil production in the field appears to be from four or five separate sandstone intervals. These sandstone intervals may be correlated from the electric logs run on the majority of the wells.

Waterflooding was established in EFCU in 1955. Water injection began in the WFCU in 1958. The fieldwide waterflood was suspended in 1986. The combined primary and secondary recovery was 49% OOIP for the EFCU and 35% OOIP for the WFCU. For this project, effort was concentrated on the WFCU, which had an estimated OOIP of 36.7 MMbbl and a much lower combined recovery than the EFCU. Of the 136 wells drilled in the West Unit, 68 are still open in the producing sand. The 68 wells are listed as 39 production, 27 injection, and 2 water production wells. The production wells are being either pumped or swabbed. The total fieldwide oil production rate prior to the initiation of the polymer project was approximately 85 bpd.

In the West Fiddler Creek Unit, approximately 15% OOIP was produced by primary recovery, which was conducted by the solution gas-drive mechanism. The waterflood, which was abandoned by the previous owner of the unit, recovered an additional 20% of OOIP in the WFCU. The ratio of secondary to primary recovery was approximately 1.4 for the WFCU. The adjoining EFCU (in the same sand) had a ratio above 2.6. The lower waterflood recovery in WFCU was apparently caused by a poorly designed line drive pattern, which was quite different from the peripheral flood used in the EFCU. Early breakthrough of water occurred in producers along the crest of the structure, which is the east-west centerline.

In 1992, a cyclic CO$_2$ injection pilot was conducted in the WFCU in well W49. Prior to the CO$_2$ injection, a single-well tracer test (SWCT) was conducted. The SWCT indicated there was sufficient oil remaining around the well to warrant testing. Also noted was the need to establish a waterpad around the well to contain the CO$_2$. To create this pad, 11,000 bbl of water was injected. Although the cyclic CO$_2$ injection was not highly successful, the injection of water did increase production in surrounding wells. In late 1992, on the basis of CO$_2$ results, Texaco, Inc. (at that time a coparticipant in the field) evaluated the possibility of reactivating water injection to increase production. Using their in-house field files and numerical simulator, Texaco identified several areas with high residual oil saturations (sweet spots). An estimate based on the recoverable OOIP from a combination of primary recovery and a well-designed EFCU waterflood suggested that there was still more than 5.8 MMbbl of moveable oil in the WFCU. This estimate was a lower limit of oil that was believed to be recoverable simply by restarting the waterflood with an appropriate pattern. Water reinjection was reinitiated in November 1992 and has continued in selected wells.
The proposed enhanced-recovery process is based on two independent processes that have been used with relative success in other petroleum reservoirs. The combined process consists of a modified polymer process with or without a near-wellbore reservoir conditioning. The polymer process may be either a channel-blocking process or an imbibition stimulation process. Both processes stimulate entry of water into low-permeability zones. The stimulation produces a more uniform and controlled flood of the producing interval than does conventional waterflooding. The process being used, the Polymer Augmented Imbibition Process developed by TIORCO Inc., is designed to stimulate the imbibition. The near-wellbore treatment, as proposed, consists of injection of potassium chloride and potassium hydroxide to permanently fix the clays and reduce the residual oil saturation in the near-wellbore area. This treatment is used to improve the relative permeability to water in the wellbore region, permitting a wider injection interval for the polymer process. The combined process can also provide increased injectivities, improve oil mobilization, and increased vertical and areal sweep efficiencies.

A similar program has been successful in the same formation just updip but separated from Fiddler Creek. Hochanadel and Townsend (1990) reported a projected recovery of 30% of OOIP in the Townsend Newcastle Sand Unit, where the primary was 13% OOIP. Reservoir quality was poorer than in the WFCU. In the Townsend Unit, the TIORCO process was applied after primary production, but before water injection had taken place.

The TIORCO process has shown to be suitable for establishing and maintaining water injection efficiency in the Townsend Unit. Stabilization of clays is known to be essential to a successful waterflood of new wells in the Newcastle Sand in this area.

The polymer-augmentation and clay-stabilization processes have been tested separately and together in other formations with relatively good success, and application and operational data exists for these processes. The clay-stabilization process has been successfully demonstrated in several clay-sensitive reservoirs (Nugent et al. 1975; Sloat and Larsen 1984; Sydansk 1984). The polymer-augmented imbibition process has been used both with and without clay stabilization as a secondary recovery technique in some midwestern and western reservoirs with considerable success (Sloat and Brown 1968; Haines 1985; Hochanadel and Townsend 1990). To date, no literature has been found that indicates that this process has rejuvenated an essentially abandoned field that has undergone extensive waterflooding.

**EXPERIMENTAL TASKS**

The project was divided into three tasks: Planning and Design; Field Implementation; and Operations, Monitoring, and Evaluation. Planning and Design began with a data review that formed
the basis for developing the final project design and implementation plan. The final design included a reevaluated injection/production scheme, placement of the injectors and producers, and sizing and layout of the water/polymer injection and produced fluid handling and treatment facilities. Field Implementation incorporated all aspects of putting the final design into place, including modifying all injection and production wells and existing facilities to handle the polymer solution and any required preinjection well treatments. Operations, Monitoring, and Evaluation was the major portion of the project and consisted of the operation, monitoring, and analysis of the process and its application.

**Planning and Design**

Sufficient data existed within the files of the operator to determine the reservoir characteristics. The injection and production data from the previous waterflood was also available, which was helpful in determining the continuity of the reservoir properties. During the initial funding year, the reservoir data in both the cosponsor’s file and in a report generated by Texaco, Inc. was reviewed. Two adjacent test areas were selected on the basis of this information and their close proximity to the main injection facility. The test areas are in the north-central portion of the WFCU. Initially, Pattern 1 consisted of injection well W40, with producing wells W41, W42, W43, W45, W48, and W49. Pattern 2 consisted of injection well W66 and producing wells W70, W71, W72, W95, and W134. To help contain the injection from the two primary injectors, W40 and W66, it was decided to incorporate some of the injectors on the boundary of the two pilot areas. Accordingly, injectors W55 and W56 were added between the two areas, and W26 and W29 were added to the east of Area 1. The test areas therefore consisted of two primary and four secondary injection wells and 11 production wells. Pattern 2 was approximately 1.5 times the size of Pattern 1. Other open wells in the pilot areas that were not on pump were routinely checked by swabbing to identify if any oil movement was occurring.

Pattern area volumetrics were estimated using the limited data on the initial water and oil saturation. Initial cores suggested an average water saturation of 32.2% PV. Earlier work by Texaco, Inc. suggested a fieldwide average of 15% PV. The reservoir volumetrics used were based on the average between these two saturations (23.65% PV). The past performance of the pilot areas was modeled with TIORCO’s Secondary Recovery Analysis Model (SRAM) and was used to predict and compare potential polymer-augmented and waterflood performance. Preliminary estimates by TIORCO project 4.4 MMbbl of incremental production for Fiddler Creek from the fieldwide polymer process application, which is an additional 12% of the OOIP after the first four years of injection. The ultimate incremental recovery at abandonment is projected to be 8.0 MMbbl, an additional 21% of OOIP.

The long-term test designed by TIORCO consisted of three phases: (1) 77 days of injection of a 300-mg/l cationic polyacrylamide, (2) 15 days of injection of a 300-mg/l anionic polymer to ensure injectivity of the polymer, and (3) 369 days of injection of the 300-mg/l anionic polymer and
a 30:1 mix of the crosslinker. Also, it was determined that in the WFCU it was not necessary to conduct the clay stabilization treatment because the process was being applied to old wells where water injection had been used for years and complications from the clays had already been realized.

Before the polymer program was started, all production wells were checked for integrity. It was not practical to install a rod pumping system in one of the wells initially selected, so that well was monitored and bailed when any change was noted. All other wells selected for pumping systems were recompleted and placed on production. Prior to the application of polymer, all production wells were pumped and all injection wells received water at approximately 1,500 psig.

Since the project area resides within a fully developed oil field, the majority of the infrastructures required to implement the project already existed. Two Madison formation water supply wells were present to supply makeup water for the injection project. Production batteries and water injection facilities were also in place from the previous fieldwide waterflood. All project wells were used in the previous waterflood. The only addition to the system was the polymer mixing facility and an additional triplex pump to inject the concentrated polymer into the main injection line.

**Field Implementation**

To initiate testing, the primary injector in Pattern 1, W40, was selected for channel-blocking treatment. W40 was chosen because of the production response of the closest producing wells to changes in the injection rate. The well treatment was the injection of 1,050 bbl of 1,500- to 4,500-mg/l MARCIT gel. One of the controlling factors for the injection was that the injection pressure should not exceed 1,500 psig. Because of the 1,550-psig injection pressure, the actual injection consisted of 53 bbl of a 1,500-mg/l solution. Although the treatment was small, a slight increase in the oil production was noted for the nearest production wells. However, the small injection volume did lead to the shelving of the treatment for the primary injector in Pattern 2, W66, until results from the long-term polymer injection become available.

One month after the channel-blocking treatment of W40, the long-term, deep-penetrating polymer injection was initiated. This phase of the program was initiated on December 2, 1998, into all six injection wells. The first phase consisted of 14,500 lb of CAT-AN® 260 injected at an average concentration of 344 mg/l (Figure 1). This was followed on March 8, 1999, by Phase 2, consisting of 3,200 lb of anionic polymer, HI-VIS® 350 at 300 mg/l. Phase 3 was started on March 24, 1999. This phase consisted of the addition of a crosslinker, TIORCO® 677, with the HI-VIS® 350. Phase 3 was terminated on May 21, 2001, after the injection of 33,100 lb of HI-VIS® 350 at concentrations of 150 mg/l to 600 mg/l. Crosslinker at a 30:1 polymer to crosslinker mix was also injected during this phase.
Figure 1. Cumulative Polymer Injection
RESULTS

Phases 1 and 2 were conducted as planned. The injection pressure increased during this time from 1,400 psig to 1,600 psig, but returned to 1,400 psig by the end of Phase 2 (Figure 2). The total injection for both patterns was 166,885 bbl with the rate decreasing from 1,550 bbl/d to 1,250 bbl/d over the injection period (Figure 3). Pattern 1 accounted for 43.1% of the injection with the remaining 56.9% going to Pattern 2. Injection rates for the individual wells can be found in Appendix A.

Approximately one month after starting the crosslinker in Phase 3, the injection pressure increased to 1,700 psi, the maximum allowable pressure, and the polymer injection was suspended. The cause of the rapid increase in pressure was an oversight by the field operator when the injection rate decreased because of increasing pressure while the daily input of polymer and crosslinker remained the same. This resulted in polymer concentrations of nearly 600 mg/l. To remedy the problem, the wellbores were treated with Chlorox to remove the buildup of polymer from the walls, and water injection without polymer was continued until mid-June 1999. Polymer injection was reinstated at a concentration of 150 mg/l with no crosslinker. One month later, crosslinker was restarted. The system remained on the 150-mg/l polymer until October 1999, when the polymer concentration was increased to 200 mg/l. At this point, the maximum allowable injection pressure was increased to 2,000 psi, followed by a second increase to 2,600 psi after approval of the Wyoming Oil and Gas Commission.

For the remainder of Phase 3, the polymer concentration continued at approximately 200 mg/l. During this period the total injection for the two test areas was 1,150 bbl/d to 1,400 bbl/d when injecting into all six wells. To maintain the injection rate, the injection pressure was slowly increased from 1,700 psig to 2,100 psig. Total injection for Phase 3 was 709,064 bbl. Pattern 1 accounted for 42.4% of the injection with the remaining 57.6% going to Pattern 2.

The monthly production in Pattern 1 increased from approximately 200 bbl of oil and 1,500 bbl of water to 700 bbl of oil and 8,000 bbl of water with the restarting of the waterflood in late 1992 (Figure 4). The WOR for this same period increased from approximately 7 to 15 (Figure 5). This performance increase was close to that predicted by Texaco, Inc. in 1992. The introduction of the polymer into the waterflood in late 1998 did not appear to have much effect on the total pattern area. The major effect was on well W48, which was a flowing well prior to the polymer and ceased to flow within three months of starting the polymer. This essentially reduced the number of wells in the pattern by one since a pumping unit could not be installed in W48.
Figure 2. Injection Pressure
Figure 3. Daily Injection Rates
Figure 4. Daily Production Pattern 1
Figure 5. Pattern 1 Water-Oil Ratio
If the production were evaluated against the number of active pattern wells (Figure 6), then a case for a small polymer effect could be made because after W48 ceased the production did not significantly change. The trace of the number of active wells also shows the difficulty the operator had with maintaining active production wells during the course of polymer injection. There were repeated well shut-ins caused by mechanical problems, severe weather, and a lack of field personnel in the region to address problems. Cases of polymer enhancement for individual wells can be made, but no well except W48 showed a significant change after initiation of polymer injection. Individual well results are shown in Appendix B.

Pattern 2 production showed a significant increase after the waterflood was reinstituted with the monthly oil rate increasing from the 300- to 400-bbl range to the 700- to 900-bbl range (Figure 7). Water production paralleled the oil production with the WOR becoming fairly constant at 6 (Figure 8). The production increase caused by the restart of water injection was what Texaco, Inc. had predicted earlier. The addition of the polymer into the waterflood did not have much noticeable effect on the total pattern area in the 2.5 years of injection and monitoring.

Evaluating the production against the number of active pattern wells (Figure 9) essentially shows that production to date in this area has been a function of the number of wells and not the polymer. No well in this area has shown a significant and lasting enhancement during the polymer-injection period. Individual well results are shown in Appendix B.

Because the area of Pattern 2 is about 1.5 times Pattern 1, the effect of the polymer may not be evident at this time. Also, the polymer is fairly stable for a few years. Therefore, the total effect of the polymer may be seen in the future because the operator is going to continue the waterflood in the unit.
Figure 6. Pattern 1 Production versus Well Count
Figure 7. Daily Production Pattern 2
Figure 8. Pattern 2 Water-Oil Ratio
Figure 9. Pattern 2 Production versus Well Count
CONCLUSIONS

Early in the application of the polymer, it appeared that the sweep improvement program was having a positive effect on Pattern 1 with oil production remaining fairly constant, water production slowly declining, and therefore a declining WOR for the pattern. The early effects in Pattern 2 were not as evident, but some changes in individual wells and the reduction in the total permissible injection for the pattern were encouraging. The decrease in permissible injection and the resultant higher injection pressure were taken as indications that the higher-permeable channels were being blocked, forcing the injection into tighter areas.

These early observations did not continue to develop throughout the polymer injection phase. The oil production for both patterns remained fairly constant to the rates established by the restart of waterflooding when the number of active producing wells was taken into account. Water production declined but has stabilized in both patterns. The stabilization of the oil at prepolymer rates and water production at the lower rates can be attributed to the polymer injection, but the effect was not as great as originally predicted by TIORCO.

The less-than-anticipated sweep improvement for the patterns was negatively impacted by extended shutdowns in the injection and production systems. If the injection shutdown periods were taken out of the operating time, then the polymer injection period would have been approximately 2 years rather than 2.5 years. The frequent and lengthy shutdown periods of production wells would have affected the establishment of new flow networks. Together these two problem areas may account for the less-than-anticipated results or may have just retarded the enhancement. Continued waterflooding by the operator will answer the retardation issue.

The problems experienced in this project are those that can be expected when long-term polymer injection is added to old waterflood fields. In these fields, the injection piping has experienced degradation through internal scale formation and thinning of the walls. The scaling provides an excellent area for buildup of polymer-enhanced deposits. These deposits restrict flow. The thinning of the piping walls limits the operating pressure of the system. The problems with the producing wells are those of age, as older wells generally require more maintenance than new wells. To prevent these problems, new injection and production tubulars and pumps would be required. Since the target of this type of application is incremental oil and the operators of these fields have reverted to the independent operator, the cost of these systems would be prohibitive.

The application of long-term polymer injection to these older waterflooded fields may be questionable. But the application of a short-term (days not years) batch treatment with a high-strength, channel-blocking polymer, as used in W40 prior to long-term injection, appears to have promise based on the limited data from W40. The shutdown of the highly permeable channel between
W40 and W48, which resulted in W48 not being a flowing well as before treatment, is attributed to the short-term treatment.

Unless future results from the continued waterflood show positive effects of the long-term polymer injection, it appears that the batch-type polymer treatment is as effective and more cost effective than the long-term treatment.
REFERENCES


APPENDIX A

INJECTION RATES FOR INDIVIDUAL WELLS
Figure A1. Average Daily Injection Rate, W-26
Figure A2. Average Daily Injection Rate, W-29
Figure A3. Average Daily Injection Rate, W-40
Figure A4. Average Daily Injection Rate, W-55
Figure A5. Average Daily Injection Rate, W-56
Figure A6. Average Daily Injection Rate, W-66
APPENDIX B

PRODUCTION RATES FOR INDIVIDUAL WELLS
Barrels per day, or Ratio

Date

May-90  Jan-93  Oct-95  Jul-98  Apr-01

Water Injection
Restarted

WOR

Polymer
Started

Figure B1. Daily Oil Production and WOR, W-41
Figure B2. Daily Oil Production and WOR, W-42
Figure B3. Daily Oil Production and WOR, W-43
Figure B4. Daily Oil Production and WOR, W-45
Figure B5. Daily Oil Production and WOR, W-48
Figure B6. Daily Oil Production and WOR, W-49
Figure B7. Daily Oil Production and WOR, W-70
Figure B8. Daily Oil Production and WOR, W-71
Figure B9. Daily Oil Production and WOR, W-72
Figure B10. Daily Oil Production and WOR, W-95
Barrels per day, or Ratio

Water Injection Restarted

Polymer Started

Figure B11. Daily Oil Production and WOR, W-134