METHODS AND SOLUTIONS TO REMEDIATE INNER-WELL COMMUNICATION PROBLEMS ON THE SACROC CO_2 EOR PROJECT - A CASE STUDY

Rebecca Larkin And Prentice Creel
Kinder Morgan CO2 Co., LP

ABSTRACT

Paper addresses conformance problems with dominating eroded interwell communications to offset producers in certain patterns of the SACROC Unit Carbon Dioxide Enhanced Oil Recovery (CO2 EOR) Project in Scurry County, Texas. The opportunity to maintain optimum pressure support and desired mobility of the hydrocarbons in various patterns and areas was being lost.
Various technologies and methods were investigated and/or deployed in attempts to redistribute CO_2 injection into desired intervals and reduce the wasted cycling. The injection wells have and will be treated with solutions capable of modifying fluid flow in an extended reach away from the near-wellbore.

Applied diagnostics provided guidance for the designed remediations of the communication problems. Criteria were then established for the physical and chemical attributes needed by the conformance solutions group to address the identified problems.

Illustrated are problem identification diagnostics, selection processes for solution attributes and capabilities, and placement control requirements.

INTRODUCTION

The SACROC unit within the Kelly-Snyder field is located in Scurry County, Texas. It was first CO_2 flooded with a large scale EOR project in 1972. Today, the CO_2-EOR programs are being used in only a few regions of the United States, primarily in west Texas, southern Wyoming, and southern Mississippi due to supply and pipelines available for transport. Newer attempts now have been initiated in Kansas, Canada, and Alabama. Industry studies have indicated the ability to gain additional hydrocarbon recovery from mature units using the CO_2-EOR techniques to be among the best potential efficient methods. Many promising new developing technologies using enhanced recovery methods could also further the oil recovery in states like Texas and other oil producing regions. [Ref 1]

Today, most CO_2 and CO_2 alternating water, or WAG, floods are conducted in carbonate formations ranging from 4,000 ft to 10,000 ft in depth. As a result, reservoir pressure conditions may exist allowing for the possibility of injection outside of the desired interval or via an eroded channel within the pay interval, particularly in previously depleted zones. Variations in the in-situ permeability due to laminations and layering often result in imbalances in injectivity; and over extended flood times and volumes of injectant, deterioration of the rock due to erosion and dissolution resulting in initially fast tracking fluid paths and eventually development into highly eroded and washed out communication paths. Water and CO_2 WAG flood units in areas such as the Permian Basin of West Texas often display out-of-zone- injection or eroded fast tracking channels consisting of mostly fractures that occur due to a variety of circumstances; either mechanical or from a chemical/electrolysis reaction. Intervals within the SACROC Unit are currently displaying imbalances in flooding due to the differences in the various intervals such as permeability – porosity, acid solubility and reaction rates encountered during completion and clean-out stimulations, fairly extreme differences in stress pressures, and variances in reservoir pore pressure due to the complex nature within the heterogeneous associated layered intervals.

The Canyon Reef is a Pennsylvanian age limestone carbonate and is part of a reef complex called the Horseshoe Atoll. [Fig 1] It is highly heterogeneous and due to extreme fluctuations in sea level, conditions existed whereas an induced rapid vertical growth of the reef occurred and this allowed for sudden severe exposures. This resulted in lateral and vertical discontinuity of porosity and permeability with the presence of karsting, detrital flows, vuggy porosity, and micro-fractures. An eroded interwell communication and karsted intervals can dominate zonal injection paths and exhibit very directional fluid flow. Chert content within the various layers of the Cisco and multiple Canyon pays also is complex and causes substantial variations in flood flow paths and the porosity.

To gain an understanding of the location, the Canyon Reef of the Horseshoe Atoll, lies on the northeastern fringe of the Permian Basin. The SACROC Unit, on the eastern side of the Atoll, is its largest producing entity and is the 7th largest oil field onshore in North America with 2.8 Billion Bbls of original oil in place (OOIP).

The average reservoir properties are a depth of 6700 ft, net pay thickness of ±260 ft with up to 800 ft of closure, porosity of 7.6%, and permeability of 19.4 md.

Development has led to many injectors communicating directly to the offset producers. These communication problems are more difficult operationally when dealing with CO_2 than water because of the differences in complexity between gas and water handling, in terms of both artificial lift and surface facilities. Besides certain operational practices and completion methods which may contribute to communication problems if uncorrected, changes in depositional environment, lithology variances, and rock structures/reservoir architecture decrease the ability to gain a vertically and laterally balanced flood within this reservoir. Permeability ranges from less than 1 md to hundreds of millidarcies. Zonal porosity can vary drastically between adjacent wells. And, net and gross pay thickness can change quite significantly over short distances. Rock stresses vary from the upper Cisco pay on down through the Canyon pays and range from fracture gradients of 0.47 psi/ft in the Cisco up to 0.74 psi/ft in the lower Canyon.

Using injectivity log profiles and formation reservoir characterization studies along with identified issues for developing a step-function change needed to accomplish the desired tasks, a pilot project was launched to make a change in the flood performance.

A conformance enhanced flood management design using any solution capable of economically modifying the path most injectant was taking in interwell communications was studied. Scrutinizing a variety of options in solutions ranging from cement products, chemical systems, and mechanical means – a decision was made to use an emerging solution showing promise and capability in other areas of the Permian Basin to control fractured and eroded interwell communication problems.

A dehydrated crystallized copolymer (material consisting of dehydrated super absorbent copolymer crystals) was selected over other past attempted selections such as performing foamed cement squeezes or gel material options for the purpose of controlling the fast tracking interwell fracture communication injection and production. The ongoing project and newly developed processes and methods now used in this flood are detailed in the paper. The profile modification and diversion project was planned for and kept open to any and all methods or solutions that might be developed or tried out to address improving performance with the reservoir management treatments with a focus on improving any economical cost of work along with the future results in improved production improvements.

The project included opportunities to capture the evaluation processes to gain knowledge from lessons learned. Valuable understanding captured included advances in products and techniques being developed, identifying and discovering more details describing the problems, and applying useful processes in an effort to advance the successes and economic benefits in reducing the wastes and inefficiencies of the interwell communicating injection.

The need to address these inefficiencies and reservoir performance in the wells was to create a better economical gain going forward in this CO_2-EOR WAG flood. Based on current conditions in the studied wells displaying interwell communication, the inefficiencies in sweep and pressure support were leading to even larger communication problems that would cause higher cycling of the injectants with a greater loss of in-pay pressure support.

Key to future developments was to define and develop a method that could do both a change in current interval(s) being over-swept and also gain enough diversion to allow a stimulation treatment step; capable of gaining new entry into other pay intervals with much higher stresses and requiring a greater pressure to direct a flood into.

SACROC CO_2 EOR PROJECT – HISTORY AS REFERENCED IN PRIOR SPE PAPERS

The SACROC Unit was discovered in 1948, comprising the majority of the Kelly-Snyder Field. The field went under primary depletion with the main drive mechanism being solution gas expansion. Reservoir pressure rapidly declined and in 1953, the bulk of the Kelly-Snyder Field was unitized. In 1954 a water flood was initiated to restore reservoir pressure and improve oil recovery. The operator implemented a crestal waterflood in which water was injected along the center (the spine) of the field. In 1972 CO_2 injection was initiated at SACROC [ref 2]. With limited CO_2 supply, the response in oil production to CO_2 injection was limited. During water and CO_2 flooding, H_2S also was introduced to the reservoir via sources outside of the unit. Shortly after CO_2 injection was initiated, the Unit's oil production peaked with rates exceeding 200,000 BOPD.[ref 3] After peak production, the Unit went on a decline.

During the decline several projects were conducted along with much well work in an attempt to halt the decline but to no avail. [ref 4] In 1995, several CO_2 pilots consisting of 5-spot patterns were started. These pilots utilized large CO_2 injection volumes at miscible conditions. As a result, the decline of the Unit's oil production was arrested. Infill drilling and pattern realignments together with large CO_2 injection volumes this decade caused oil production to increase to more than 31,000 BOPD.

FLOODING PROBLEMS

The Unit's Reef Formation is characterized as highly heterogeneous and due to extreme fluctuations in sea level, conditions existed whereas an induced rapid vertical growth of the reef occurred and this allowed for sudden severe exposures. This resulted in lateral and vertical discontinuity of porosity and permeability with the presence of karsting, detrital flows, vuggy porosity, and micro-fractures. Often problems displaying out-of-zone injection or preferential paths within the interval are first noticed because of cycling problems with one or more of the injector's offsetting producers. The direct communication between injectors and producers is referred to as cycling and appears as a very rapid spike in injectant production volumes in the producers shortly after the injection cycle starts. Without corrective action this increase in injectant production is usually accompanied by a decrease in oil production. The other criteria that is used in identifying problems is monitoring offset wells that are not performing based on pressure support if the injectivity is lost to another zone which is not connected to the desired interval.[ref 5] Conditions of the in-zone rapid breakthrough via eroded rock are characterized by the offset producers freezing up due to the rapid through-put of CO_2. SACROC has mitigated freezing in recent years with staged pressure surface separation systems.

For the Permian Basin in general, wellbore losses of integrity and casing usually display similar conditions with a potential of water influxes and cross-flows prevalent within the producing intervals. Often observed are injectivity patterns that are following natural eroded paths that lead across the flooded units and cause dynamic interference and dilution to any solution meant to remedy the interwell communication conditions. Hazardous conditions also exist with the presence of H_2S and Iron Sulfide content. The interwell communication conditions and their physical nature of problems need to be addressed in defining and characterizing a solution's attributes and capabilities. The conditions of any solution's placement capabilities and required control while attempting to address the problems are needed to obtain any success.. [ref 6, 7]

Capabilities desired to remediate the identified problems were based on:

- High probability of success
- Return on investment potential
- Amount of data available to give better understanding
- Maintenance and past workovers
- Corrosion problems that exist
- Equipment replacement
- Facilities capabilities and optimization needs
- Required treatments for paraffin and scale removal via acidizing, etc.
- Disposal needs and cost, regulatory requirements, and environmental issues
- Rapid communication conditions leading to additional problems such as increased near-wellbore corrosion, loss of wellbore integrity, and difficulty in maintaining a packer seal.
- Performing reservoir evaluations instead of just an individual well evaluation, which can be influenced by mechanical or near-wellbore problems, should be used to define the benefit in addressing problems with injectivity losses or inefficiencies. Any resulting solutions engineered to remediate the problems can then address reservoir sweep problems and interwell communications. The anticipated outcome still is directed toward the goals of increased production and recovery with an associated reduction in operating costs.
- Historical injection profiles, completion and stimulation details, and timeline occurrences are obtained on the subject wells.

Candidate wells were selected for treatment according to a prioritized list of injector/producer pairs or combinations of associated wells that result from sub-par flood performance, including reserve recovery and total gas-oil ratio, shown in Figures 8-9. These wells were reviewed again to eliminate those with known mechanical problems or restrictions, and a diagnostic program was generated.

Annual injection profiles are run on each SACROC injection well under normal injection rates and pressures to track vertical injectivity over time. The profile survey logs are usually obtained on both the water and CO_2 cycles to determine whether injection is entering the same intervals similarly regardless of the injection fluid and compiled in Petra Software for evaluation and interwell porosity plotting. These injection profiles were used for designing and placing the conformance treatments, which were tailored to each well's requirements per a matrix selection process based on the Injection Index based on Step Rate Injection Tests and weighting factors based on the particular formation associated with the dominant profile entry. After a conformance candidate was selected, a well bore clean-out followed by one or more injection profiles was then obtained on the subject wells before a final design treatment was made.

Ideally, needed is an understanding of where the injectant fluids have gone at different rate conditions. The conditions that vary were the pressure changes associated with different injection rates and the variations in injection profiles. Either step rate tests for determination of injectivity or multi-rate analyses are conducted with a logging tool in the hole that is equipped with a release device capable of placing a specified amount of radioactive material into the flow stream above the logging tools. A required base gamma analysis is used for determining variations. The testing is performed with velocity releases of isotopes placed in segments through the wellbore, followed with a large intensity shot of isotope placed above the entry zone. The process is started at a reduced rate below the daily injection rate. By releasing the velocity shots and an intensity shot, engineers can trace the injectivity of the tag to determine its path and location. Comparison analysis with both intensity and velocity shots give a better understanding of injectivity and the static condition's crossflow determination. Combining these analyses with a temperature analysis also provides a better understanding of injectivities and near-wellbore effects. The subsequent runs for multi-rates are taken at incremented increased rates after time is allowed for the previously shot isotopes to clear and for fluid entry to stabilize. Crossflows are determined between each step as well. The next rate steps are performed by increasing the injection rate and ensuring that the bottom hole injection pressure (BHIP) does not exceed the fracture gradient if not already fractured. The focus is to determine if entries vary at the different rates and accompanying changes in BHIP, if any, on each injection phase with water and/or CO_2. [Ref 8]

Variances of entry into the reservoir are analyzed, and limitations can also be determined for the placement technique. Ideally, the modification solution's criteria and physical attributes are established from the injectivity evaluations using a developed matrix selection process.[ref-6, 7, 9, 10]

As usual, along with determining the extent and condition of the problem, there is opportunity for determining the criteria a treatment solution must fit and the placement techniques that should be used. Various placement techniques exist and can be planned for in selecting the correct procedure. Maximum injection pressure can be determined for bullheading the treatment fluids based on the communication problems identified. Differential pressure responses may indicate the tortuousity aspects of fluid entry into specific portions of the reservoir. When rates exceed certain velocities, such solutions as cement slurries, gels, or particulates can be pumped into a specific portion of the formation. With normal permeabilities ranging from 1.0 to 200 md in the Unit's reservoir, reduced the chance of injecting a gelled fluid at the placement rate determined from each of the multi-rate injectivities at matrix flow. This analysis helped us determine if a treatment could be placed where it develops a blocking and diverting effect without entering other undesired portions of the formation. Further investigations showed that a specific pressure developed from varying injectivity could cause undesired entry; this information was used to limit the treatment pressure. The solutions that can be placed under the established criteria in the multi-rate injection analysis are established with this analysis. [ref 9, 10]

The nature of the architecture that accepts high rates of injection over relatively short vertical sections are characteristic of weaker rock being leached out and eroded from years of water and CO_2 injection creating fracture-like vuggy structures. Frequently, the reservoir pressure is increased in CO_2 floods to a desired pore pressure (to assure miscibility), multi-rate injectivities with profiles can see these features, but the pressure responses will be "masked" and hidden because of the artificial pressure maintained on the reservoir. Assumptions can be made that the problems lay within a permeability feature and not those of a fractured system, leading operations to pick the wrong technique and product to address the problem.

Diagnosing and analyzing the necessary placement controls based on the identified conformance problem is the primary task needed to achieve success. In developing a solution for the identified problem, it needs to have the capability to successfully be placed at the right part of a reservoir without becoming an obstruction to beneficial production and fluid displacement. [ref 9, 10]

Choosing and designing the proper conformance solution based on the needs of the subject wells also leads to a successful and long-term remedy for the problems. Many solutions are available that have properties such as (a) liquid systems with in-situ polymerization post placement, (b) gel systems used to build diversion in the high injection flow paths, (c) fibrous materials giving a flexible blockage, (d) crystallized copolymer systems capable of entering and modifying highly leached out and fissured - rapid fluid transient fissures and fractures, (e) reactive chemicals with both internal and external catalysis, and (f) high strength - highly efficient displacement materials capable of blocking off or modifying fracture systems with rapid communication between well-pairings. [ref 9, 10]

Performing post-treatment evaluations for modifications or changes in the well performance is needed to insure that the problem has been successfully remedied. Reflection on what may be discovered and learned, without making judgmental assumptions, is incorporated into the investigation for a solution and placement mechanism.

PROBLEM IDENTIFICATION – COLLECTING DATA

The following are required in this accumulation of problem identification resources:

- Reservoir characterizations and descriptions. [Utilization of DSS and Petra resources]
- Clarification of the existing drive mechanisms
- Maps and schematics – Well, structural, and completion diagrams [Internal database systems]
- Data files – Electronic and physical collection of files containing all well information, well tests, and production and injection information.
- Type logs – Logs with formation tops on subject producing interval and additional geological markers shown. [Geological descriptions loaded into Petra]
- Individual production and injections plots – Plots on all wells for the same time period, rates, and within a focused area of associated wells. [Data base and montague of profiles]
- Test results: tracers, profile and temperature logs, production logs, pressure surveys, pulse testing, etc.
- Historical injection rate and pressure data
- Operator opinions and historical observations [determinations from the operation group and clarifications of historical events]

SOLUTION DEVELOPMENTS - PLACEMENT SELECTIONS

Historically, the initial desire by operators is to run to a solution without thoroughly identifying the problem and the conditions in which it exists. [ref 6, 7,9, 10, 11] The best solutions should be sought that can be described from analyzing the problems or needs, but often they are not considered when the solution treatments are applied usually in a bullheaded treatment letting the solutions go to the least restrictive path. Ideally, operators perform diagnostic tests to correctly interpret problems and then develop the necessary criteria and requirements offered by the solutions. The required attributes for a solution on the wells are defined according to the desired parameters of needs described in the investigation. The available solution's limits, qualifications, and "ability to be placed" are developed accordingly. The designer should match the best solution system or techniques to meet the necessary attributes required and in doing so, provide the most favorable economics for each well or pairs of wells treated.

Solutions are based on the extremity of required placements and the proximity to the wellbore. Some of the considerations made are:

- Near-wellbore problem
- Casing leaks and integrity problems
- Channels behind casings
- Barrier breakdowns problems
- Completion out of zone
- Reservoir problem
- Poor areal sweep conditions – heterogeneity, discontinuity, etc.
- Gravity segregated layering
- Cone-in/cresting (cusping) problems
- High-permeability streaks (with or without crossflows)
- Stimulation out of zone.
- Interwell channeling (fissures/fractures/eroded channels, etc.)

HIGHLY ERODED CHANNELS WITH COMMUNICATION AND OUT-OF-ZONE LOSSES – A SOLUTION IS CHOSEN

Foamed Slurry: [Production Wells]

Cement squeezes were considered as an option if the highly eroded or fracture features are identified as potentially very open and not tortuous. Foamed cement would also be a good selection if concerns on influxes of gas and water and displacement efficiencies were noted. With high amounts of influxing water, all cements can be diluted and dispersed, causing a failure if not highly viscous and bound with the energy contained in foamed slurry. Past successes using foamed slurry in shutting off fracture communication and CO_2 breakthrough in over 30 producers (1998) in the SACROC Unit was successful in placement and remediation of the production problems. The production of the wells squeezed with foamed slurry did not show a breakthrough communication within the fracture systems for the duration of their respective project life.

Crystallized Polymers (CP): [Injection Wells]

Decision was made to attempt to squeeze off the first candidate injection well's interwell communication with a crystallized copolymer super absorbent system (CP) as a first step with a planned 1,000 sk foamed cement squeeze to follow if needed.
The first candidate with a highly defined communication aspect treated with a sufficient pressure build and witnessed profile modification such that the follow-up decision was to only place a 100 sk conventional cement squeeze behind for near wellbore matrix strength. It was noted later that this cement squeezing step could most likely have been eliminated.

Successive wells were then treated based on their diagnosed problems with the CP with designs based on their injection rates, profiles, and aspects of offset communication. No tail-in cement was utilized. Twelve treatments in total were performed in the 4th quarter of 2006. Some treatments resulted in sustained post treatment improvement due to possible vertical injection profile modifications; two treatments showed little change in profile; and, one treatment failed as CP set too early while placing due to the water being too fresh - for a success ratio of 75%. Due to most of the offset producers not having a pump for production, evaluations of the improvements or lack of improvement was not determined for over 6 months.

Placements using these materials was made down the current injection tubulars working rigless; a practice that can save expense by avoiding the need for a workover unit. Removal of the crystallized copolymer if desired could be obtained by reactions from bleaches or oxidizers once squeezed into the CP's mass. No CP-related damage to offset production wells or production facilities has occurred to date.

Based on observations of placement pressure builds and lack of diversion into other vertical entries; determinations has been made that an acid stimulation process is needed in conjunction with the conformance step. Desire is to build enough pressure capable of gaining entry into other pay intervals with acid – having been placed across these intervals. Solutions used had to have the capability to be compatible with the acid stimulation system and also strong enough to withstand the stimulations breakdown requirements.

CRYSTAL POLYMER PROCESS:

CP materials are water-swellable but not water-soluble, 100% crystalline synthetic polymer. They absorb hundreds of times their own weight in water ranging from 10 up to 800 times based on their particular grind, carrier and present available aqueous fluid, and the specific manufactured base material. These CP materials initially were intended in the oil and gas industry for use primarily as a lost circulation material and to address near wellbore remediation problems and reservoir architectural features needing modification by cementing zonal isolation and conformance.
These materials were chosen based on their attributes and capabilities in creating a blockage in the communicating fracture systems. Their use to address fracture and fissure communication in order to stop these highly communicating features from thieving most of the injection and transmitting almost directly into offset producers also needed to be favorable economically.

The superabsorbent copolymers (CP) currently used are sodium acrylate-based polymers which have a three dimensional network-like molecular structure. The polymer chains are formed from the joining of millions of identical units of acrylic acid monomer, which has been substantially neutralized with sodium hydroxide (caustic soda). [Ref 12]

Crosslinking chemicals tie the chains together to form a three-dimensional network – 100% crosslinked. This enables CP's to absorb water or water-based solutions into the spaces in the molecular network, forming a gel and locking up the liquid. The chemicals tie the chains together to form a three-dimensional network. This enables CP's to absorb water or water-based solutions into the spaces in the molecular network, forming a gel like solution and locking up the liquid in suspension.

As the polyacrylamide is being developed [manufactured] under temperature, it is put into a reactor and crosslinked still under temperature until a certain viscosity is reached. It is then run through an extruder and out on a mesh belt where it hardens and then to the chopper where it is cut to a specific size and bagged. The crosslinked process will help keep it insoluble.

The crystallized copolymers are resistant to degradation by CO_2, bacteria, and temperature below 275 °F. [Ref 12]

CRYSTAL PROCESS STEPS

The time in which the crystallized copolymers will start to hydrate is over 20 minutes if in fresh water and at temperatures less than 110°F. Use of produced brines (8.9–9.2 lb/gal) will have a delay of around 45 minutes before the crystals initiate their swelling. Placement may be defined around this feature. Once placed into the injectant stream, wells may be closed in for a period of 30 minutes to allow the crystallized copolymers to thoroughly swell. The material will swell from 10 to 800 times its crystal weight in fresh water and 5 to 100 times its crystal weight in produced water. The wells can then be placed back on injection and analyzed for profile if desired or evaluated for pressure responses. They can also be tested for control of out-of-zone injection losses and influxes. [Ref 10, 11, 12]

If desired, a follow-up stimulation process can be performed to remove damage from other portions of the wellbore. The crystallized copolymer has been researched and noted as having resistance to acid, bacteria growth, and CO_2 degradation. [Ref 10, 11, 12]

Treatment volumes are adjusted per ongoing injection and placement trials in stages of injecting a volume of materials and displacing – then testing with pressure fall-off or another profile prior to determining if other steps of placement are required. Once the post-placement period of the material has ended, a measured and observed pressure decline indicating a change in fluid losses via the fracture systems or near-wellbore losses would indicate changes. An extended and changed pressure decline would indicate enough material had been placed to stop injectivity or production from the intervals. The wells are then placed back onto injection or production for analysis and performance testing.

QUALITY CONTROL

Laboratory analysis is performed to determine the set times and viscosity performance for the CP treatments based on downhole injection temperature. The crystals were mixed with a variety of carrier fluids to determine the best for the particular well's placement requirements. **Table 1** shows some of the analysis on the various carrier fluids and their swelling time ranges. Determining the capabilities of a CP to control the interwell communication problems, an extrusion analysis was conducted and shown in Figures A-J. Figure 13 shows a typical placement of the CP materials into an interwell communication fracture.

PLACEMENT CONSIDERATIONS

The treatments in the SACROC Unit using CP materials were all done using placement down the current injection string and packer. The majority of the injection problems were going into an array of communicating systems identified by the 'Multi-Rate Injectivity Analysis with Profiles' run in the Pretreatment diagnostics and for evaluation after each treatment step for notation of modification.

A later treatment utilized a Coil Tubing to run in and spot acid across the entire perforated intervals so that an enhanced ability to break-down these perforations could be available while performing the CP treatment. Normally the treated wells in 1996 were entered prior to injecting with CP to modify their profiles with a Coil Tubing and circulated clean to gain ability to run a full profile analysis and to remove fill of scale and paraffin.[Figure X] The added step of spotting acid has shown to be a very important step in diverting into perforations that have not before been broken-down.

The technique considered for placement of the CP treatments on the wells with interwell communication were performed using this "Bullheading Placement" technique whereas an acceptable rate and pressure restriction is used to determine the placement down the current injection or production string. Using the current tubulars and relying on rate/pressure determined from profiles, the rigless placement on injecting a solution were identified in the diagnostics used to determine the problem. [Ref 10, 11] Methods and techniques in performing a rigless workover on an injection well were also developed to address several needed requirements and regulatory stipulations.

Mechanical packer placement techniques are also an option if the solution injection is determined to need this for the best placement control. Using a packer to isolate perforations, leaks, or a portion of an openhole completion into which the treatment is to be placed gives a conditional control.

Additional steps of injecting these crystals were made following profiles run immediately thereafter or can be made later if determined from a pressure transient fall-off test that indicates remains fissure, fracture, or channel.

Due to the physical nature of the CP – their placement would only be into this void space and not into any of the rock structure. This selective placement was utilized to minimize the damage to the rock matrix while having a solution capable of filling and blocking off the high transmission of fluids via the communication network. Design was to place enough blockage and restrictive materials into these open and conductive paths deep into the formation to prevent future re-entry in order to divert injection into other portions of the reservoir currently not receiving fluid movement and possibly never having received any.

Because of the expense and ability to acquire pulling units for workovers, the costly procedure of killing a CO_2 injection well, pulling its injection string, and rigging up to do other kinds of squeeze technique for communication damage along with the reduction in time spent doing workovers going from 10-30 days down to 2-3 days performing the CP Process were giving savings as high as $250,000 per well. The ability to treat the well without having to utilize a workover unit, pull the well following killing it, and take a chance in not being able to gain a packer seat following the squeezing of the loss interval were some of the operator's needs and desires. The ability to modify and control injectivities without needing a post drill-out or additional steps of stimulation and perforating were also desired.

Background information on SACROC and examples of the techniques and upfront evaluations used to address an 'interwell communication problem' on an injection well are shown in Figures 1-23. The interval(s) displaying the communication was identified from running multi-rate injection profiles using both intensity and velocity analysis with radioactive tracers. This method defined the problem and the placement requirements that would be needed. A complete example of an actual performance treatment performed on SU Well No. 141-1 is displayed in **Figures 12 – 16a&b.** Another example of an actual performance treatment performed along with a follow-up treatment on SU Well No. 143-1 is displayed in **Figures 17-21**. Still another example of an actual performance treatment performed along with a follow-up treatment on SU Well No. 85-1 is displayed in **Figures 22-25.**

CONCLUSION

Operations gained successful results in building blockage - capable of gaining diversion when acid treatments are also applied to the process. The work in addressing techniques and methods needed to control undesirable zonal injection needs additional work for addressing other wells displaying similar problems. To understand the capabilities of using the CP on eroded out communication channels, various laboratory tests and evaluations were performed and are given in the **Tables 1 and Figures A-J, Ref 12.** Some examples of the actual performance of treatments are displayed in **Figures 2 – 20.**

An evaluation of the performance and changes made on the 11 wells identified and treated in the project show the results in **Figure 21-22**. The project considered 199 wells with ESP's installed or upsized in 64 producers in the 2^{nd} half of 2005. The CP treatments on the 12 pattern injectors in the 4^{th} quarter of 2006 were done at an average cost of $105,000.

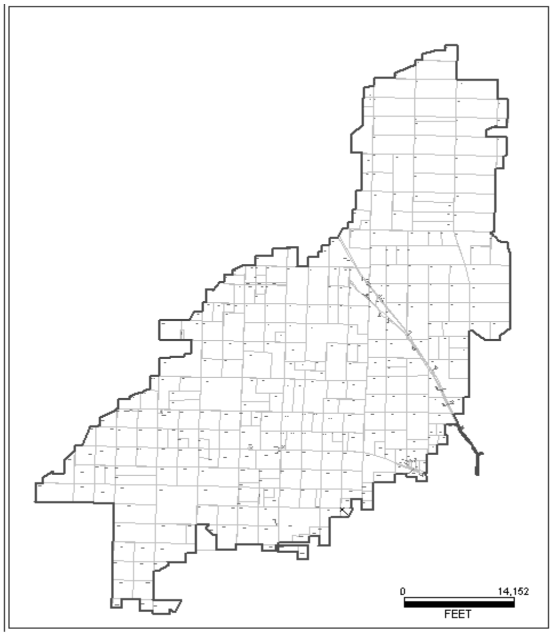
Current work using both Polymer Gels and Crystal Gels are ongoing and being evaluated as to their performance. Projects planned in the first quarter of 2008 will use various conformance processes during an evaluation process incorporating a Matrix Conformance Selection Process as a guideline for treatment selection and the type of technology used. The planned approach is to gain areal sweep in the Cisco and Upper Canyon intervals while building enough resistance with conformance materials within these past eroded flood intervals so as to give a capability to also vertically re-direct injection into the tighter and more difficult to gain entry of the low permeability Middle and Lower Canyon intervals.

ACKNOWLEDGMENTS

The authors of this paper thank the management of the Kinder Morgan Energy Partners LT, Production Logging Inc., Production Logging Inc., and Halliburton for permission to prepare and present this paper.

REFERENCES

1. Brnak, J., Petrich, B., and Konopczynski, M.R.; "Application of SmartWell Technology to the SACROC CO_2 EOR Project: A Case Study," paper presented at the 2006 SPE/DOE Symposium on Improved Recovery held in Tulsa, Oklahoma, USA, 22-26 April, 2004
2. Graue, D.J., and Blevins, T.R., "SACROC Tertiary CO_2 Pilot Project," paper SPE 7090, presented at the Fifth Symposium on Improved Methods for Oil Recovery of the Society of Petroleum Engineers of AIME, Tulsa, Oklahoma, April 16-19, a978.
3. Langston, M.V., Hoadley, S.F. and Young, D.N., "Definitive CO_2 Flooding Response in the SACROC Unit," SPE/DOE 17321 paper presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, April 17-20, 1988.
4. Hawkins, J.T., et al., "SACROC Unit CO_2 Flood: Multidisciplinary Team Improves Reservoir Management and Decreases Operating Costs," SPE RE (August 1996) 141.
5. Azari, M. & Soliman, M.F., "Reservoir Engineering Applications to Control Excess Water and Gas Production," paper SPE 37810 presented at 1997 SPE Middle East Oil Show held in Bahrain on March 15-18, 1997
6. Creel, P.G., Honnert, M., Kelley, R., Tate, R., Dalrymple, E.D.: "Conformance Water-Management Team Developments and Solutions on Projects in the Permian Basin," paper SPE 70068,presented at the 2001 Permian Basin Oil and Gas Recovery Conference, Midland, Texas, 14-16 May.
7. Green, C., Creel, P., McDonald, S., Ryan, T.: "Utilization of a Crystallized Hydrating Copolymer to Modify an Injectivity Problem in a Horizontal CO_2 WAG Injector in the South Cowden Unit, Ector County, Texas – Post Treatment Coil Tubing Acidizing Stimulation – Case History," paper SWPSC 2003 SWPSC, Lubbock, Texas April 2003
8. Cardinal Surveys Website, www.cardinalsurveys.com library giving detailed diagnostics tests and procedures. Actual profile logging performed by Production Logging, Inc.
9. Creel, P.G., Honnert, M., Tate, R., Everett:,: "Five Years of On-Going Conformance Work in the Central Mallet Unit CO_2 Flood in West Texas Yields Improved Economics for Operator;" paper SPE 101701, presented at the 2006 First International Oil Conference and Exhibition in Mexico held in Cancun, Mexico, 31 August–2 September 2006.
10. Creel, P.G., Honnert, M., Tate, R., Everett: "Central Mallett and Slaughter CO_2 WAG Units Conformance Project," paper presented at the 54^{th} Annual Southwestern Petroleum Short Course, Lubbock, Texas, April 25-26, 2007
11. Creel, P.G. & Booker, J., "Correcting out-of-Zone Injection Problems on a Waterflood in SE New Mexico," paper presented at the 54^{th} Annual Southwestern Petroleum Short Course, Lubbock, Texas, April 25-26, 2007
12. Laboratory Analysis Investigations and Reports [Confidential] - Baroid, Houston Technical Center and Halliburton Laboratory Facilities, Duncan, Okla and Odessa, Tx, May 1998, April 2000, July 2002, Sept. 2004, November 2006, February 2007.



Case Study

- SACROC Unit
  - Scurry County
  - Discovered 1948
  - Unitized 1953
  - WF 1954, CO_2 1972
  - OOIP 2.8 BSTB, 46% Recv. to date
  - 1900 well bores, 800 active

Figure 1 – SACROC Unit – Scurry Co, West Texas

Recent Unit Performance

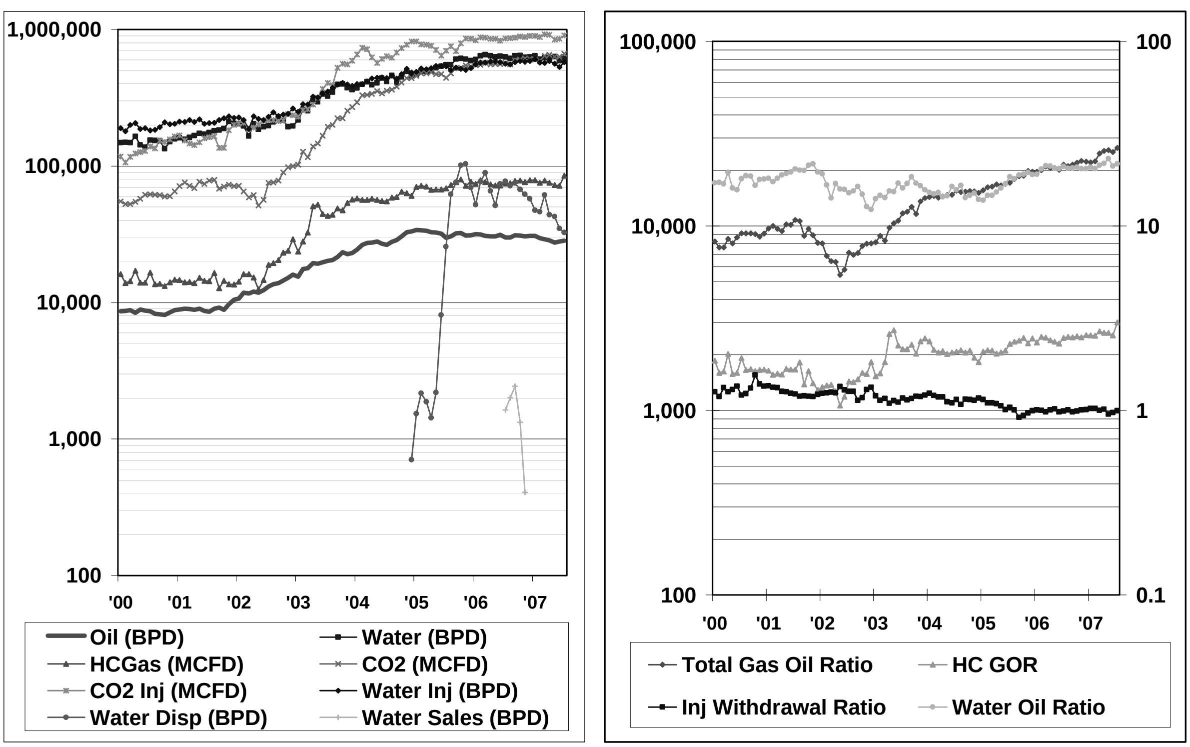
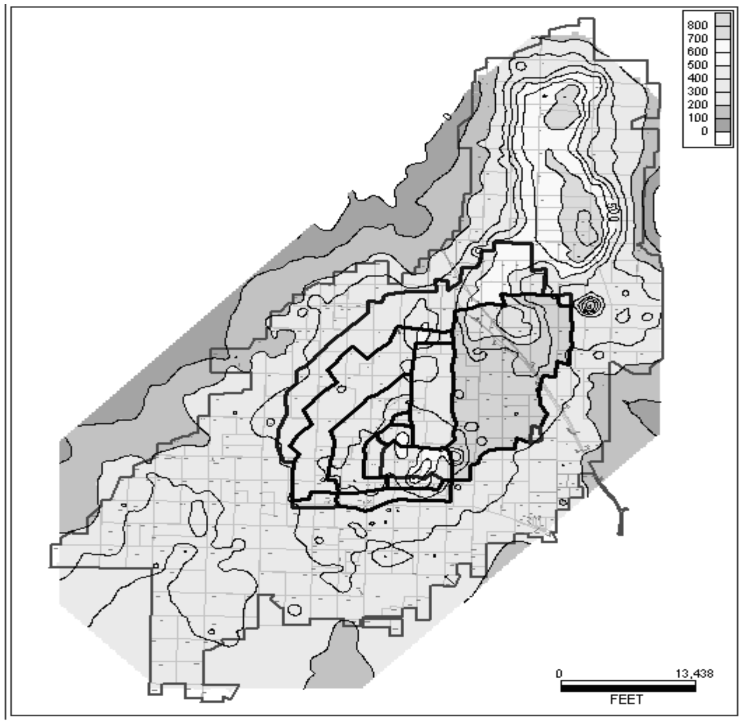


Figure 2 – Recent Performance



- BullsEye Project Performance Problems
- Under Forecast

Figure 3 – Focused Area Performance Problems

BullsEye Project Performance

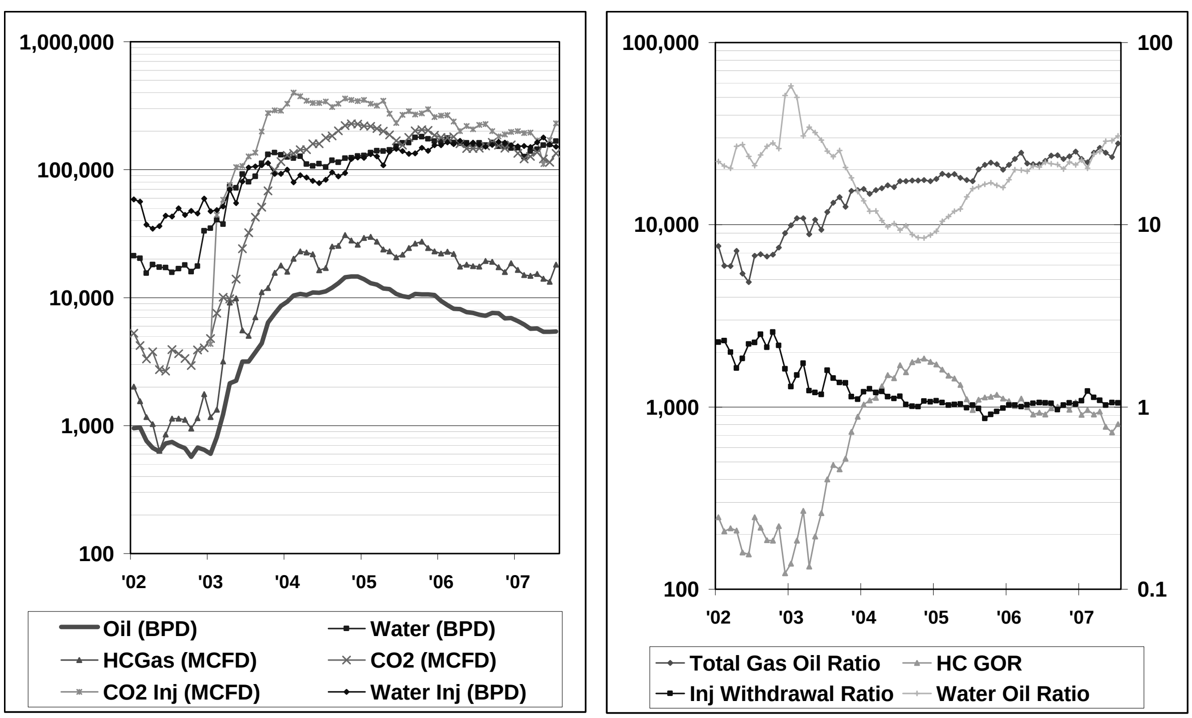


Figure 4 – Project Performance

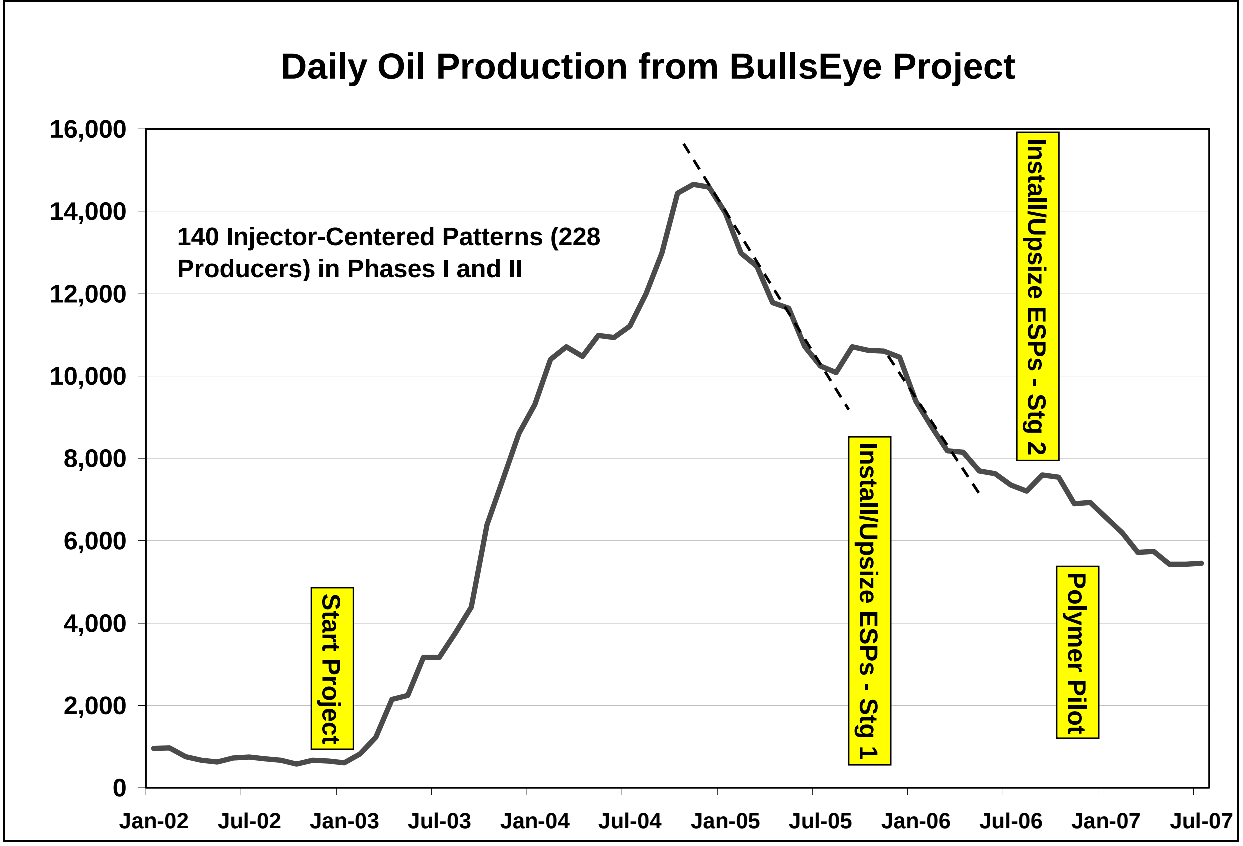
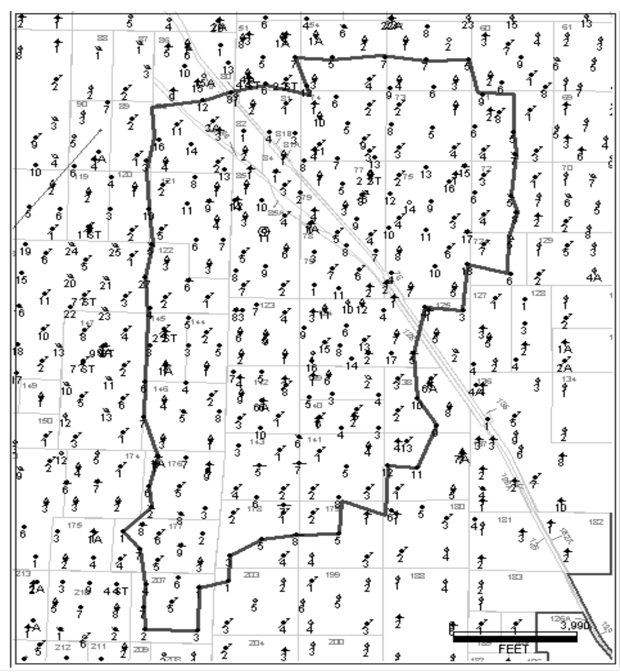


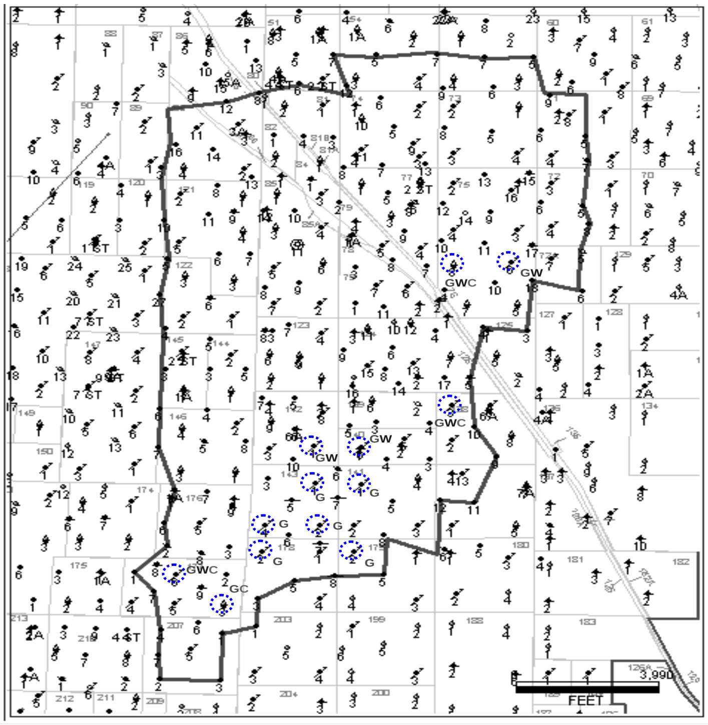
Figure 5 – Production for Focused Area



BullsEye Project

- Underperforming Oil Production versus Forecast
- Major Culprit: Gas Breakthrough
- Polymer Candidates: Thief Zone Reduction

Figure 6 – Candidate Identification

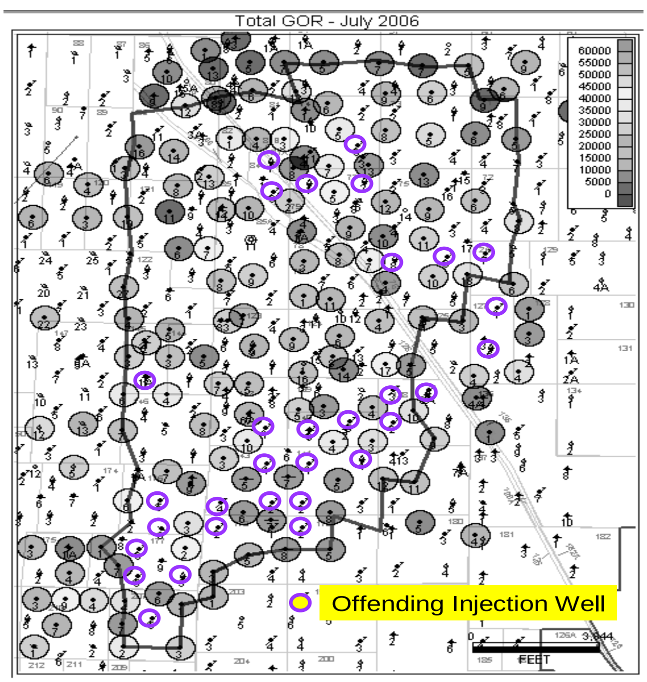


15

14 Rigless Candidates

- Top Candidates (High GOR, Low WOR, CO_2 Injection Active): 51-2 (known channel), 75-8, 138-3, 177-6
- Next Candidates (High GOR, Low WOR <u>or</u> CO_2 Injection Active): 75-6, 140-6, 142-1, 177-3
- Last Candidates (High GOR): 141-1, 143-1, 143-2, 143-4, 178-2, 179-2

Figure 7 - Candidates



11

GOR Hot Spots

- **Immediate Problem GOR Cluster**
  - **(3 or more high GOR (> 30,000 SCF/BO) producers offset to injector)**
- **Offending Injection Wells (30 wells)**
  ( ) Number High GOR offsets
  - **72A-7 (3)**
  - **74-9 (3)**
  - **75-6 (4)**
  - **75-8 (4)**
  - **77-1 (3)**
  - **77-2 (3)**
  - **81A-1 (3)**
  - **84-3 (3)**
  - **127-1 (3)**
  - **127-5 (3)**
  - **138-2 (3)**
  - **138-3 (3)**
  - **138-6A (3)**
  - **140-5 (3)**
  - **140-6 (4)**
  - **141-1 (4)**
  - **141-2 (4)**
  - **142-1 (3)**
  - **143-1 (5)**
  - **143-2 (4)**
  - **143-4 (4)**
  - **145-1A (3)**
  - **176-5 (3)**
  - **176-8 (3)**
  - **177-3 (3)**
  - **177-5 (4)**
  - **177-6 (5)**
  - **178-2 (3)**
  - **179-2 (4)**
  - **207-5 (5)**

Figure 8 – Offending Wells

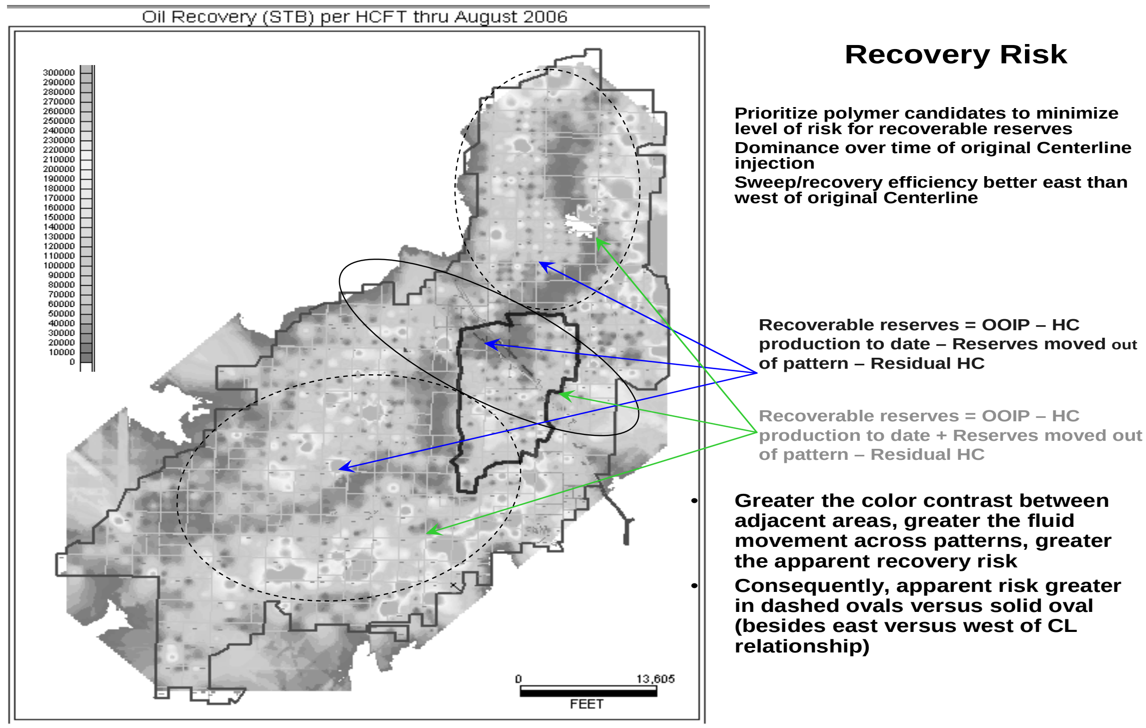


Figure 9 – Recovery Risk

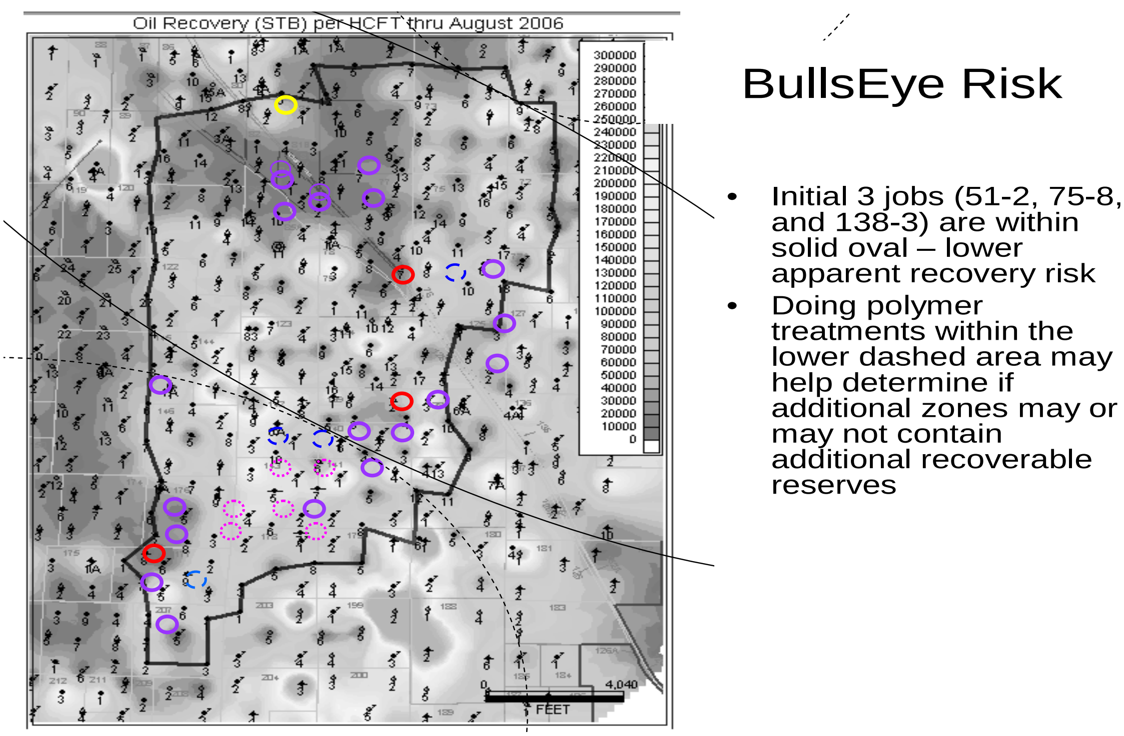
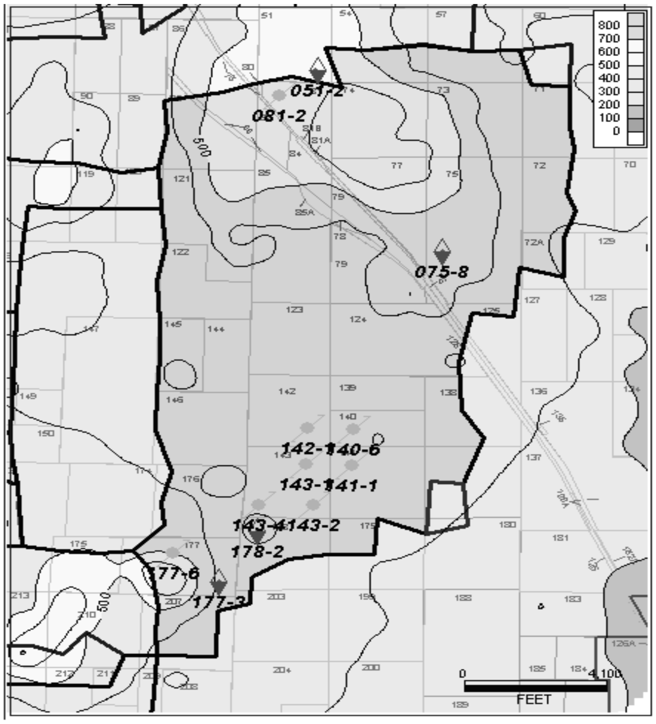


Figure 10 – Risk in Project



- **Underperforming Oil Production versus Forecast**
- **Major Culprit: Gas Breakthrough**
- **Polymer Candidates: Thief Zone Reduction**

Figure 11 – Underperforming Candidates

Example 1:

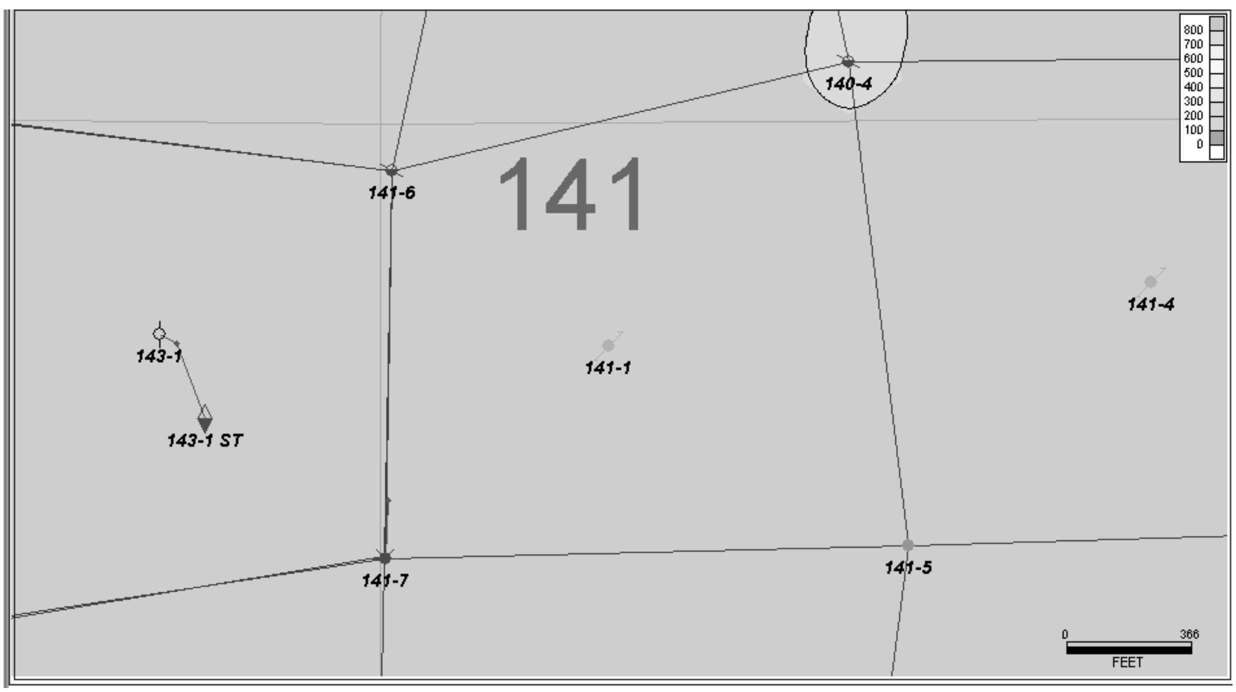


Figure 12 - Map of Location Candidate

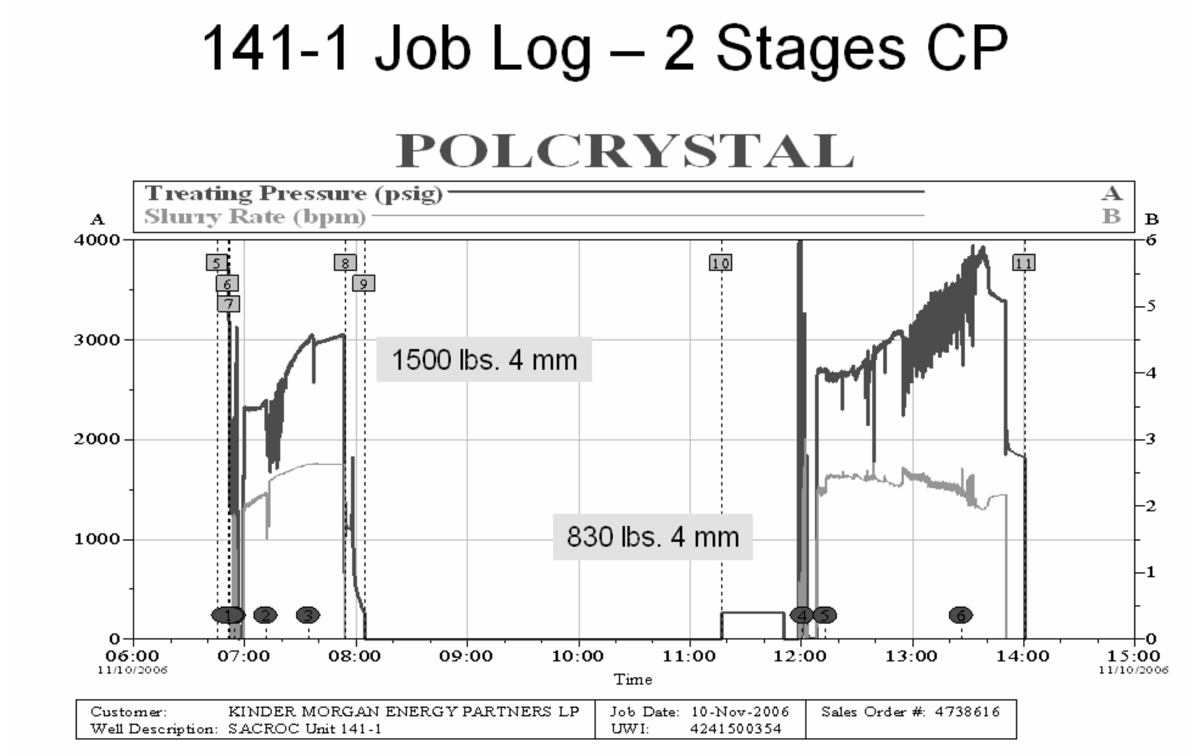


Figure 13 – Actual CP Treatment Job Log

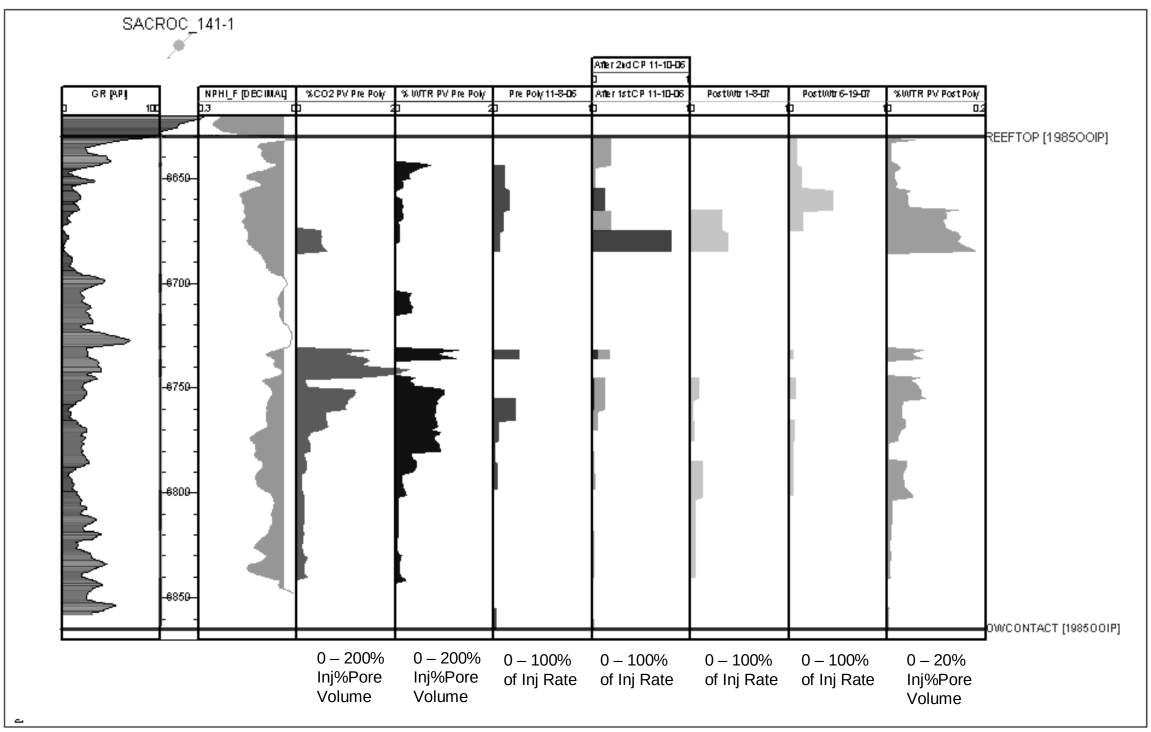


Figure 14 – Pre- Post Profiles

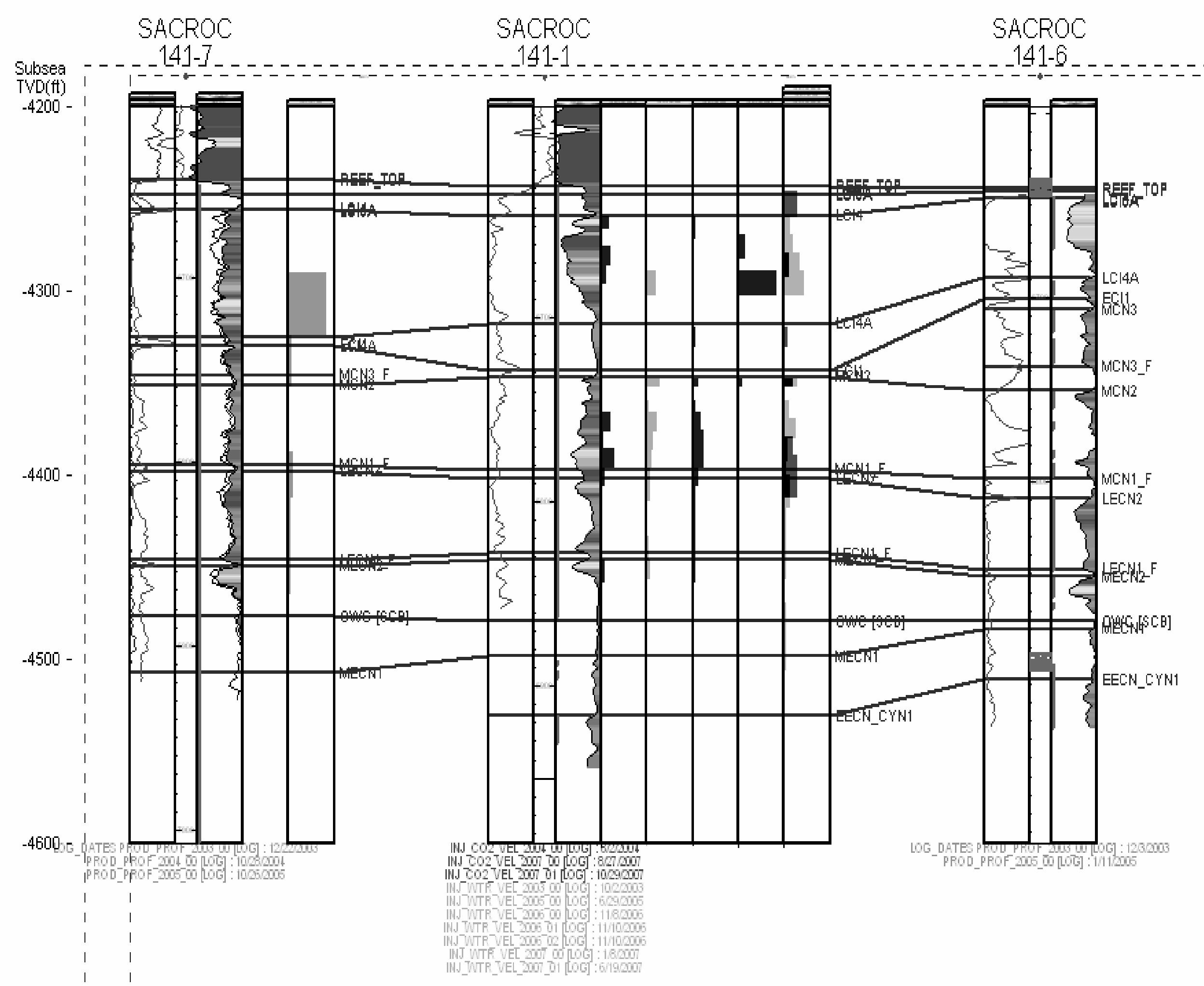


Figure 15 - Cross Section and Profiles between Injector 141-1 and its communicating offset producers 141-6 & 141-7 – Tracks reflect 2003, 04, 05, 06, & 07 from left to right.

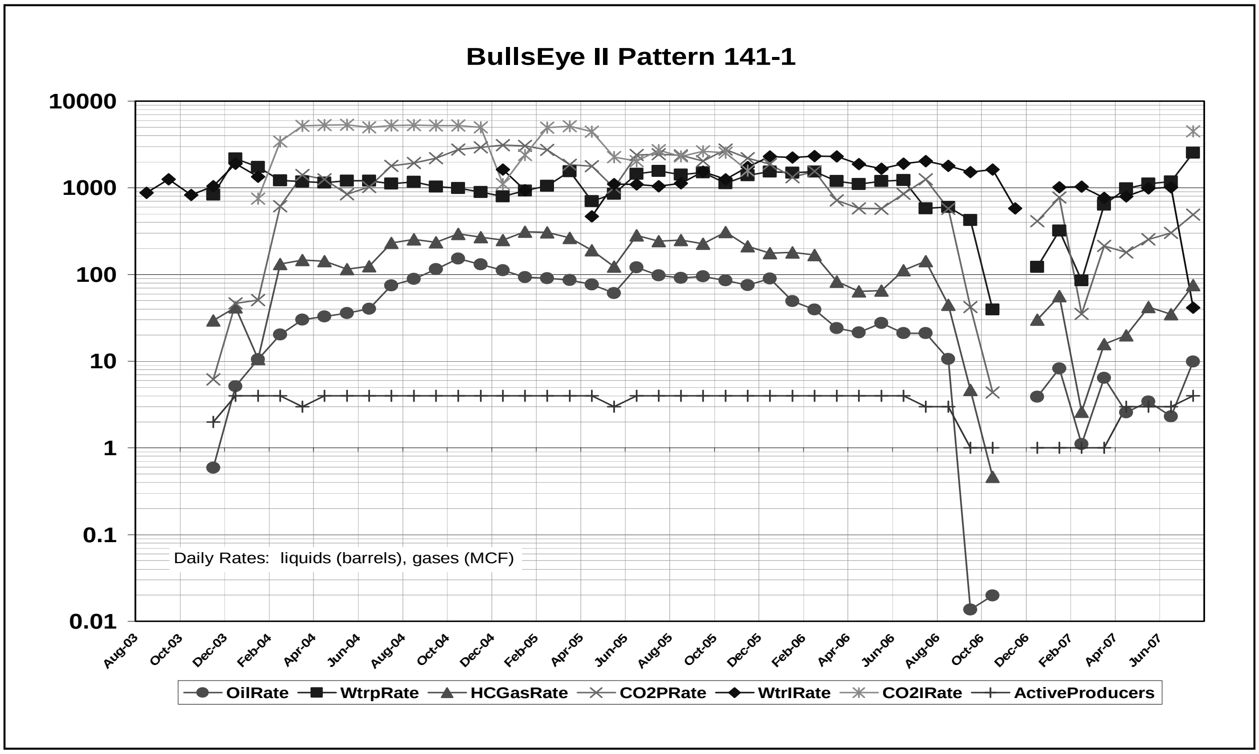


Figure 16a – Pattern Performance Aug -2007

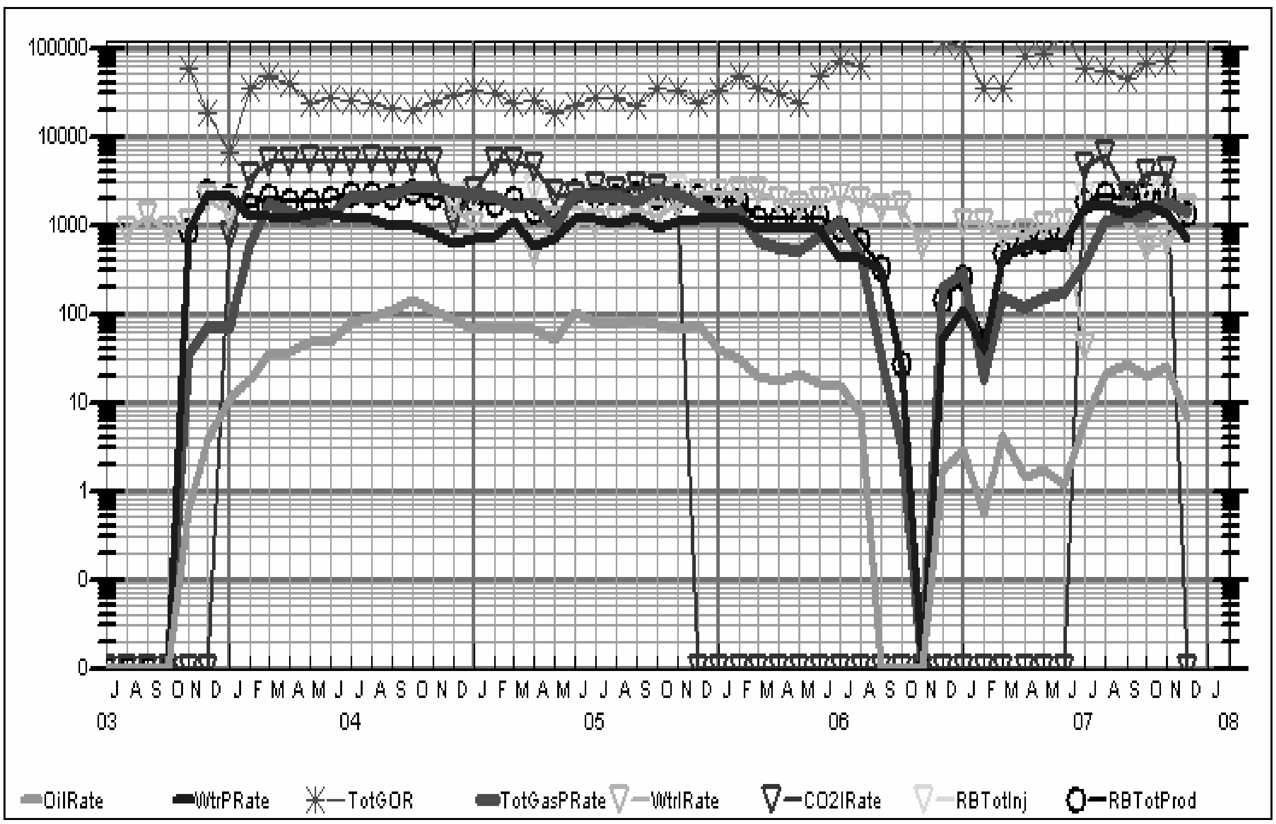


Figure 16b – Pattern Performance Jan-2008

Example 2:

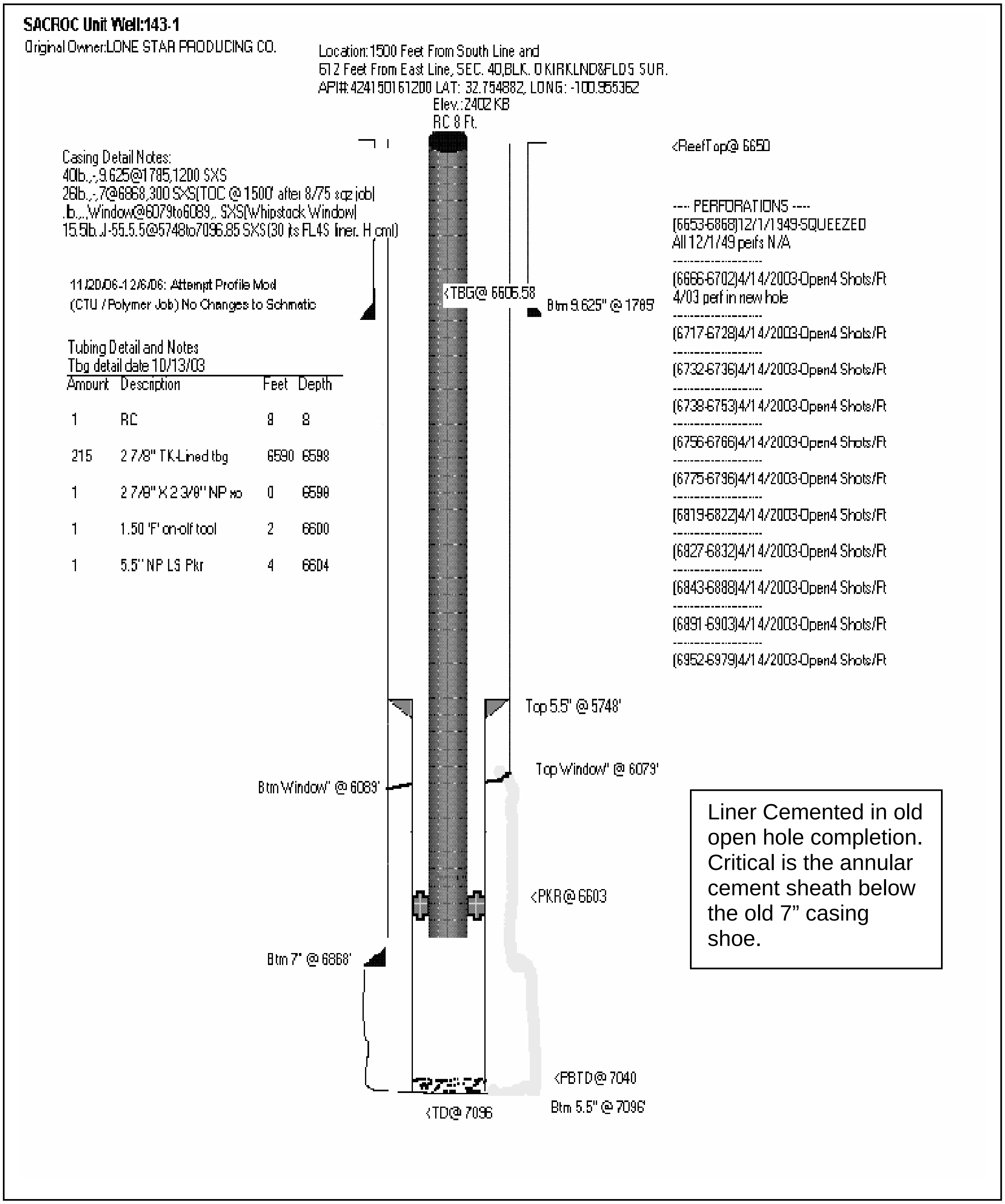


Figure 17 – Schematic of Candidate Well

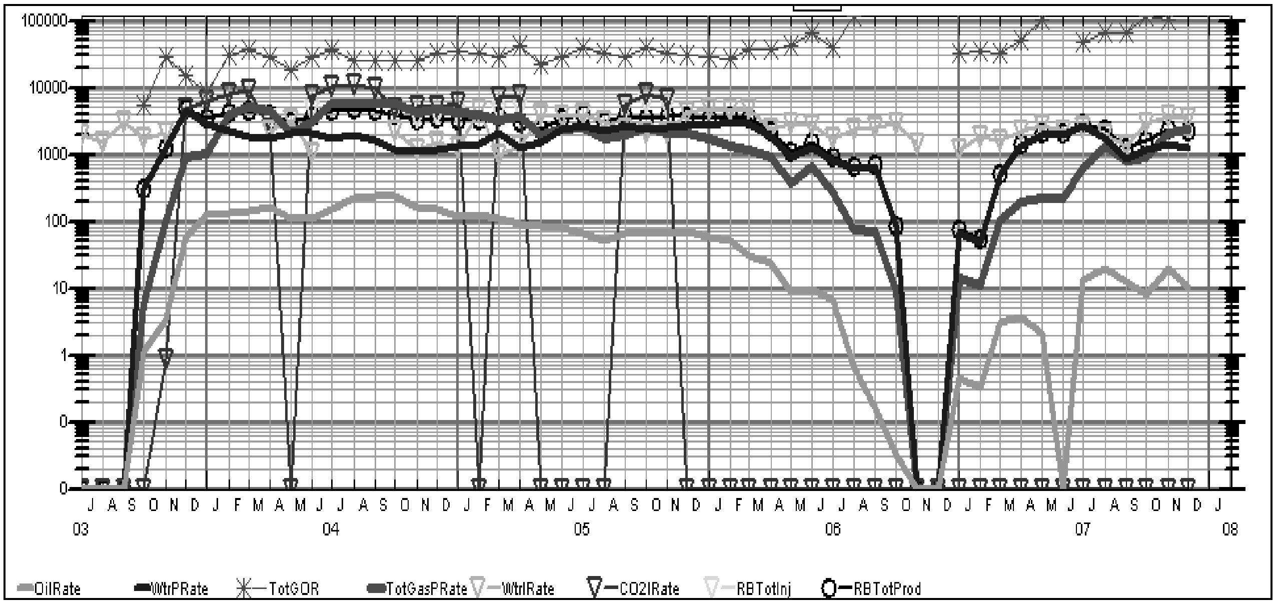


Figure 18 - Project Well – Treated in Oct 2, 2006, Followed with Stimulation in Oct 2007

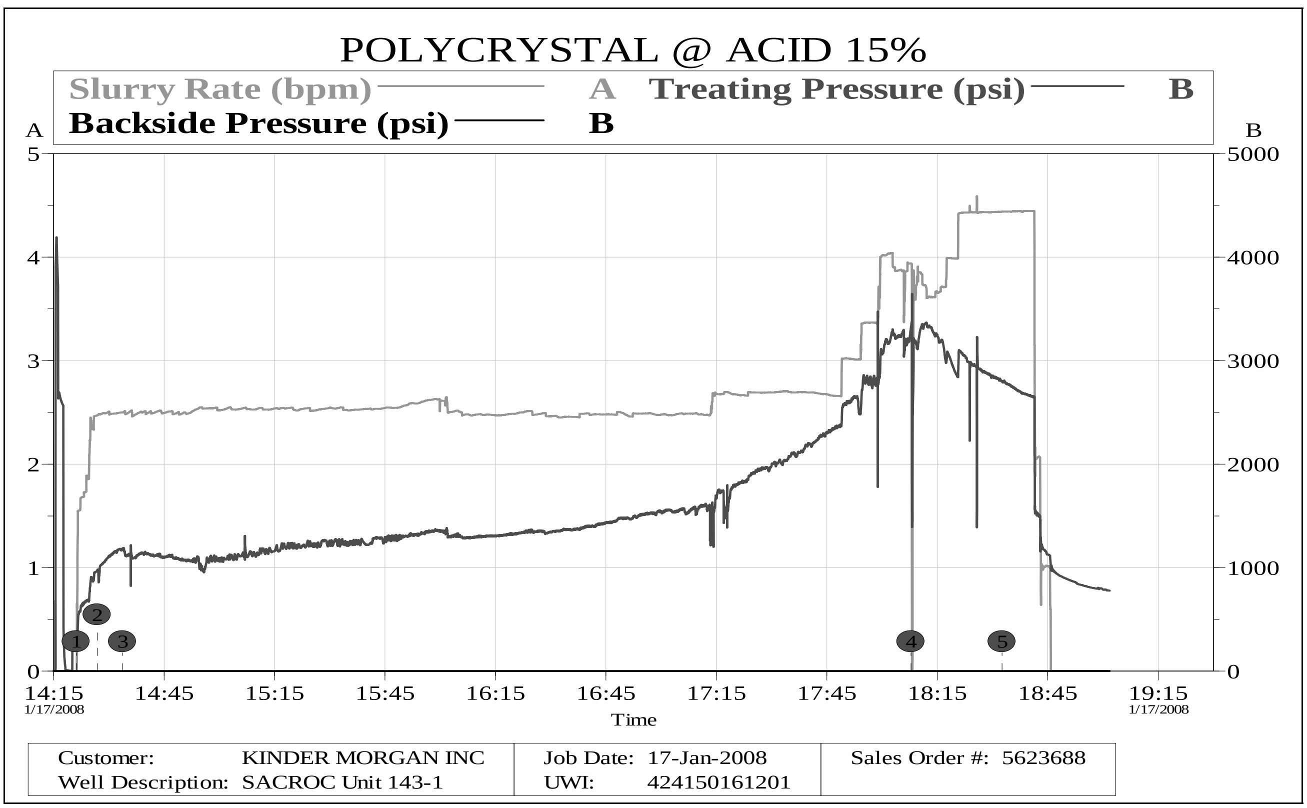


Figure 19 – Follow-up treatment with acid placed on spot from TD back up to packer with Coil Tubing prior to conformance – stimulation treatment [observed break-downs of intervals not taking injection at various BD pressures]

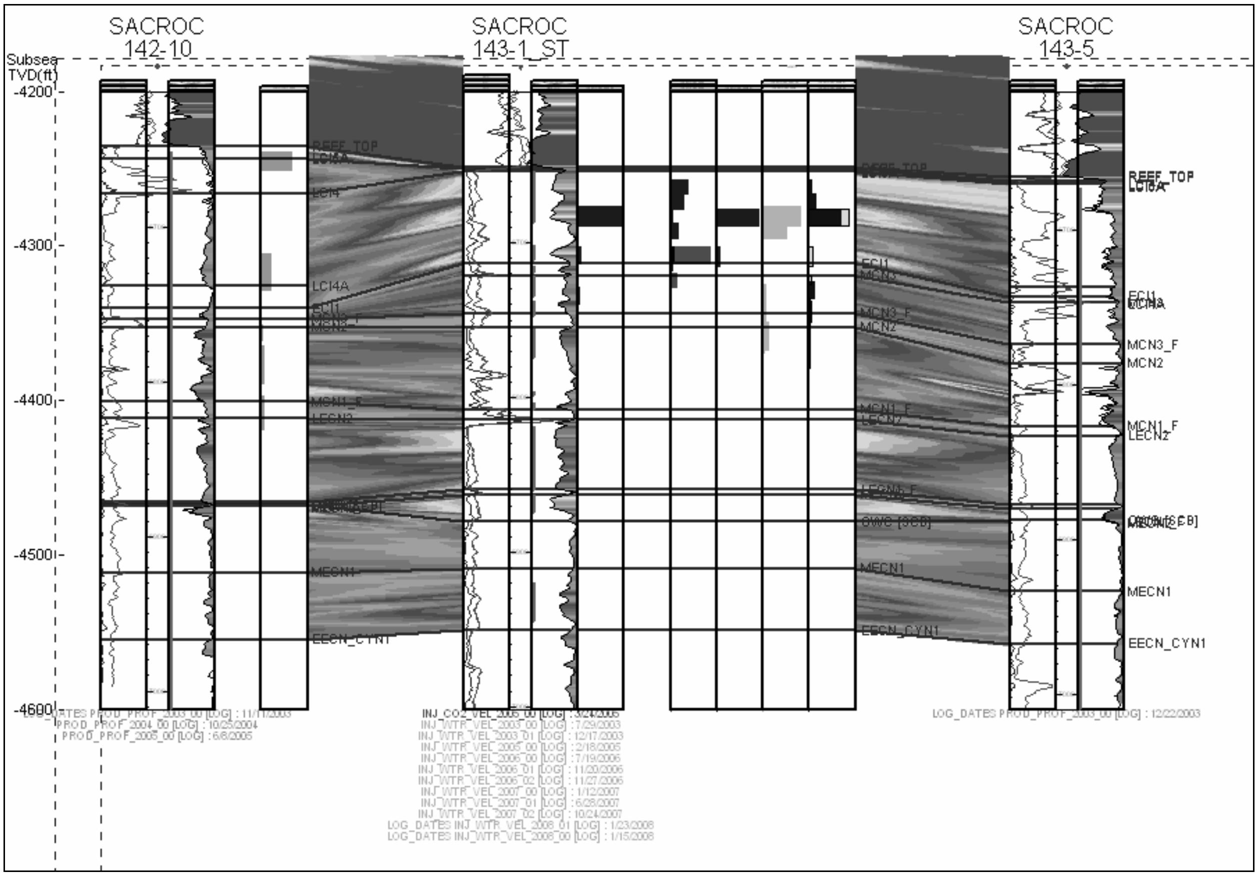


Figure 20 - Profile post follow-up conformance stimulation treatment. Tracks reflect 2003, 04, 05, 06, 07, & 2008 from left to right.

Velocity losses indicated are shown on the plot with Injection Temperature indicated possible channeling down to 6884' at time of survey.

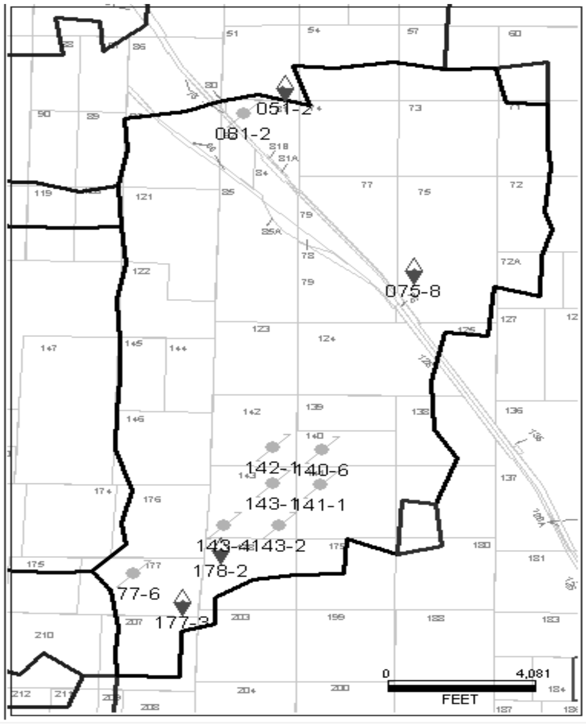


Figure 21 - Observations

Observations

- Polymer can modify vertical injection distribution
- Tracer tests on high priority patterns should be conducted to better estimate effective volume needed
- Store cut brine on site – no deliveries on the fly
- Clean out and stimulate well at start of every job
- Working polymer strength will be revealed over time as will economic success

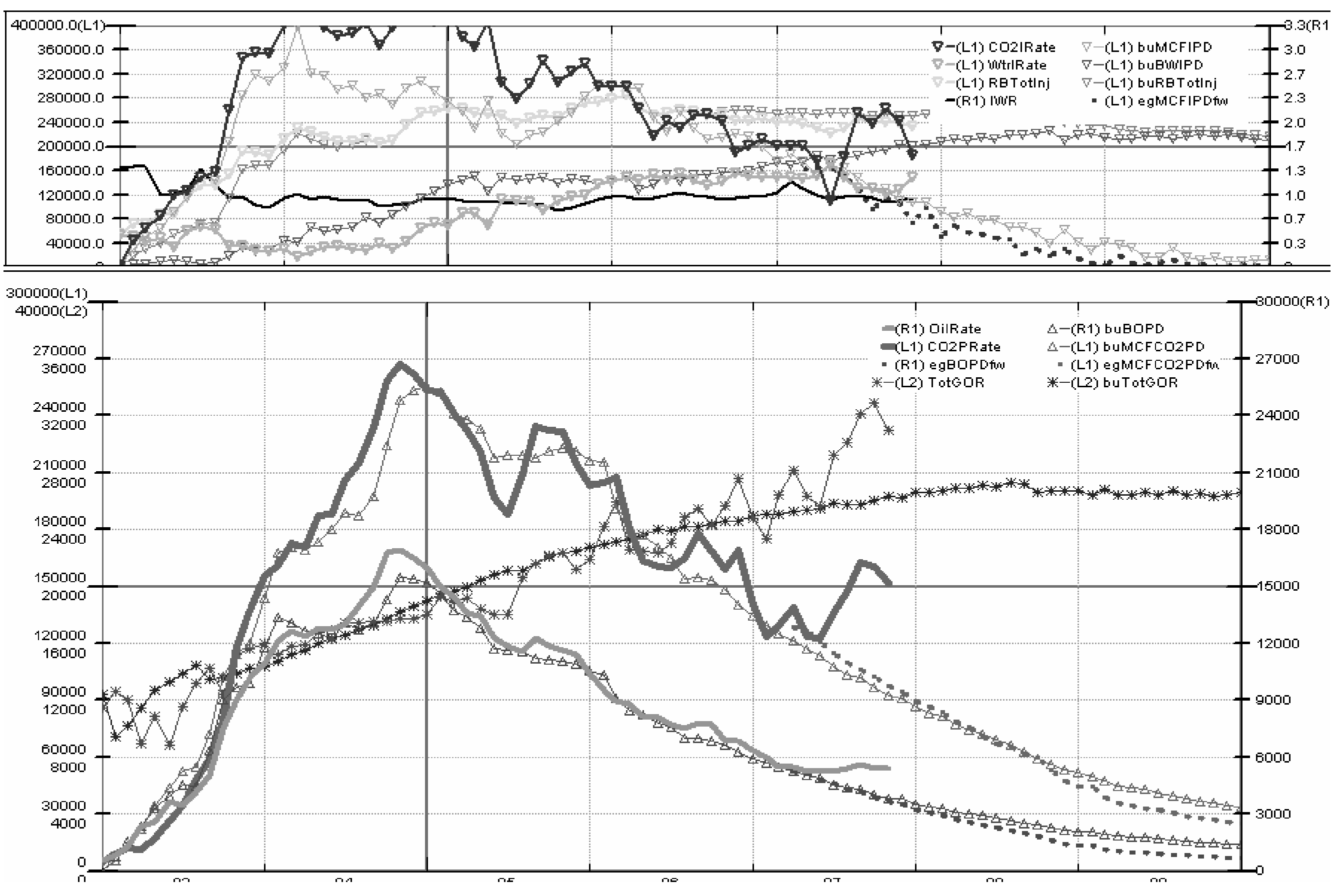
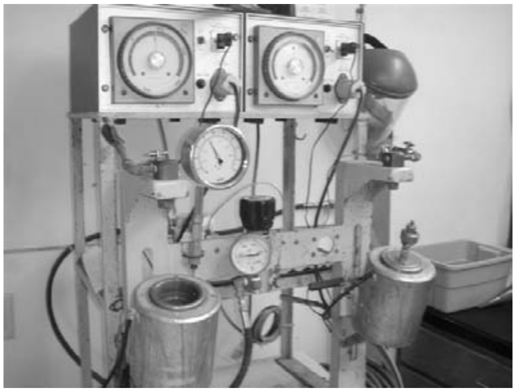
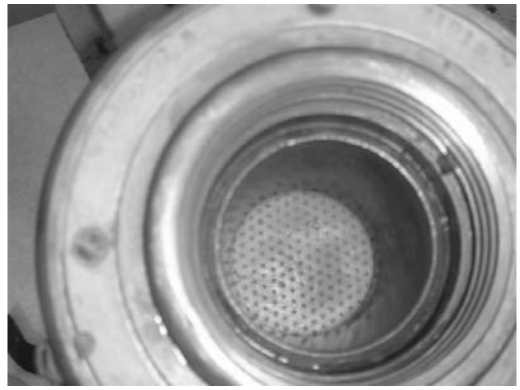


Figure 22 - Bulls Eye Project Production

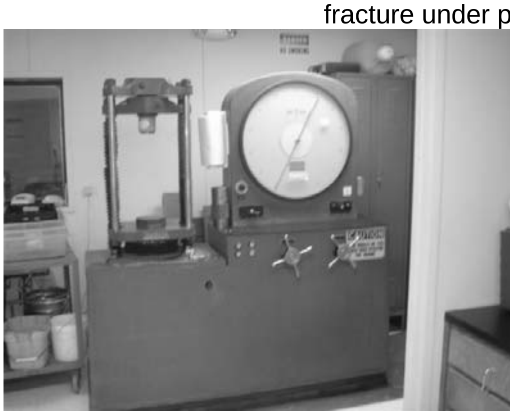
Table 1

Swelling Times with Various Concentrations and Carrier Fluids

Crystal Polymer Grind Size	Carrier Fluid	Concentration of CP in Carrier Fluid	Temp., °F	Initial Swelling Time, hr.:min.	Final Swelling Time, hr.:min.	Swelling Increase, Weight to Weight Ratio
1 mm	Fresh Water	0.05 ppg	80	0:14	0:20	500
		0.1 ppg	80	0:13	0:18	500
		0.15 ppg	80	0:12	0:16	550
2 mm	Fresh Water	0.10 ppg	80	0:17	0:24	500
		0.15 ppg	80	0:15	0:21	500
		0.20 ppg	80	0:14	0:20	500
4 mm	Fresh Water	0.20 ppg 0.4 ppg 0.5 ppg	80 80 80	0:18 0:18 0:18	0:25 0:25 0:25	500 500 450
4 mm	Fresh Water	0.2 ppg 0.4 ppg 0.5 ppg	120 120 120	0:14 0:14 0:14	0:20 0:20 0:20	500 450 400
14 mm	Fresh Water	0.2 ppg 0.4 ppg 0.5 ppg	80 80 80	0:20 0:20 0:20	0:30 0:25 0:25	500 450 400
14 mm	Fresh Water	0.2 ppg 0.4 ppg 0.5 ppg	120 120 120	0:17 0:16 0:16	0:25 0:25 0:25	500 450 400
1 mm	Brine Water,	0.05 ppg	80	0:16	0:30	125
	9.5 ppg	0.1 ppg	80	0:17	0:30	150
		0.15 ppg	80	0:18	0:30	125
2 mm	Brine Water,	0.10 ppg	80	0:20	0:30	125
	9.5 ppg	0.15 ppg	80	0:18	0:30	150
		0.20 ppg	80	0:18	0:30	125
4 mm	Brine Water, 9.5 ppg	0.5 ppg 1.0 ppg	80 80	0:20 0:20	0:33 0:30	150 100
4 mm	Brine Water, 9.5 ppg	0.5 ppg 1.0 ppg	120 120	0:18 0:18	0:30 0:27	175 150
14 mm	Brine Water, 9.5 ppg	0.5 ppg 1.0 ppg	80 80	0:25 0:25	0:40 0:45	150 100
14 mm	Brine Water, 9.5 ppg	0.5 ppg 1.0 ppg	120 120	0:20 0:20	0:35 0:35	150 125
4 mm	Brine Water, 10.0 ppg	0.5 ppg 1.0 ppg	80 80	0:25 0:25	0:45 0:45	100 50
4 mm	Brine Water, 10.0 ppg	0.5 ppg 1.0 ppg	120 120	0:30 0:30	0:55 0:55	100 50
14 mm	Brine Water, 10.0 ppg	0.5 ppg 1.0 ppg	80 80	0:25 0:25	0:45 0:45	100 50
14 mm	Brine Water, 10.0 ppg	0.5 ppg 1.0 ppg	120 120	0:25 0:25	0:55 0:55	100 50

Figures A & B - Fluid Loss Analysis Apparatus – to determine the filtration affects traveling down a fracture under pumping conditions



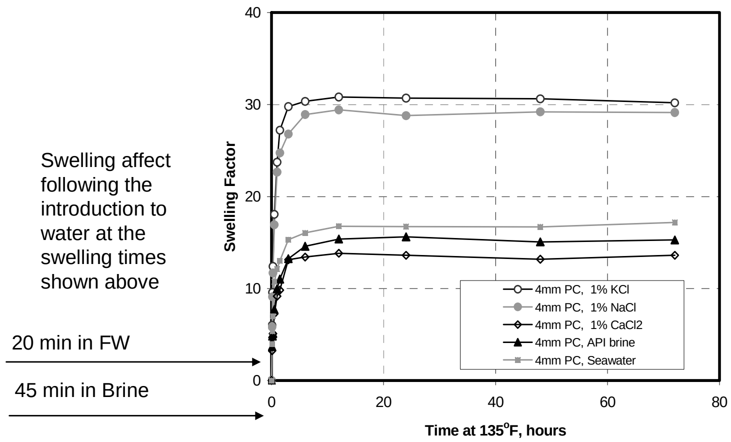

Figures C & D - Compressive Strength Tester [0 – 12,000 psi] –
Utilized to Perform Flat Plate Extrusion Testing



Figures E, F, & G - Non extruded CP following a 10,000 psi test [brass plates] – CPs show extreme capability as blockage and squeeze materials by resisting extrusion.

Effect of Carrier Fluid

Fresh Water Carrier Solution	**Swelling Time @ 100º F** **20 – 25 mins**
Produced Brine Water Carrier Solution	**Swelling Time @ 100º F** **40 – 50 minutes (generally)**



4mm PC, 135ºF

Figure H - Effect of the Carrier Fluid on the Swelling Potential

Core Flow Experiments

(Synthetic cores with simulated fractures)

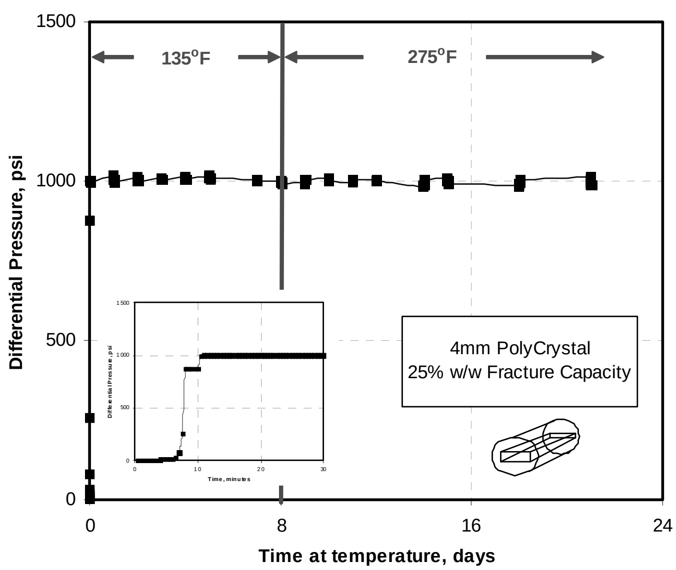


Figure J - Core Flow Experiments and Pressure Resistance to Extrusion