CENTRAL MALLETT AND SLAUGHTER CO_2 WAG UNITS CONFORMANCE PROJECT

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ABSTRACT

This paper presents lessons learned from a 6-year effort to improve and enhance field-wide influences on the Central Mallett and Slaughter Estate CO_2 water and gas (WAG) Units. The developments on data analysis, reservoir and production engineering, and solutions in these mature units have provided the opportunity to make major impacts on recovery and production rates, operation enhancements, and cost reductions.

Focus on the total reservoir and development of a framework of data included information of the reservoir, completion design, drilling and workover history, production and well-test history, logs and diagnostic analysis, and placement options. An optimum conformance solution design for each injection well and the associated offset producers were the team's vision.

Success was defined through a review of the operator's economic drivers for sweep improvement, reduction of CO_2, and water-cycling breakthroughs.

INTRODUCTION

A project was initiated in early 1998 by Occidental Permian, Ltd. (OPL) to make their large CO_2 floods and waterfloods more financially viable by addressing conformance issues.[1] The OPL joined Halliburton to form a team for addressing conformance issues and for developing the step-function changes needed to accomplish the tasks. This paper will cover the ongoing work and developed processes and methods used in the units over the past 6 years. The points of emphasis were to: (1) keep open the evaluation processes to gain knowledge from lessons learned, (2) use advances in products and techniques, identify and discover more about the problems, and (3) apply any useful process with dedicated commitment to advance the successes and economic benefits in reducing waste and inefficiency of operation.

The Slaughter Estate Unit is located on the Northern Shelf of the Midland Basin (**Figure 1**). The producing interval is the San Andres dolomite, which is part of the Guadalupian Series and is Upper Permian in age. The field is in Hockley County, Texas (approximately 40 miles west of Lubbock) and consists of several units producing from the San Andres dolomite formation. Typical completion depths are 4,000 to 5,500 ft. This layered, highly dolomite reservoir has significant permeability variations. Variations in permeability and porosity are complicated for the formation because of its layered nature, with the content of anhydrite ranging from a small percentage to it being the dominant rock content. The typical unit in this field now has been on waterfloods for over 35 years, and many units have been on CO_2 WAG for over 20 years. Two of these WAG units were chosen for this project. The continued analysis and solutions performed are on selected well pairs based on performance and communication aspects.

The reservoir was deposited in a restricted carbonate platform environment, and the San Andres in the CMU and Slaughter units are composed of a series of tidal flat cycles capped by evaporitic anhydrite and anhydrite-filled dolomites. The San Andres is found at an average depth of 5,100 ft; average permeability is 2.5 md (ranges from less than 0.1 to 230 md); and the average porosity is 10.8% (ranges from 2 to 25 %). San Andres' porosity types are mainly intercrystalline, moldic, microvugular, and fracture.

The Central Mallet Unit (CMU) and Slaughter Estate Unit (SEU) operated by OPL production are from the Permian-aged San Andres dolomite. In the Slaughter Field the CMU's main pay, San Andres Dolomite, produces from an average reservoir depth of 100± ft. The field was discovered in 1937 and unitized in February 1964, with full-scale water injection beginning shortly thereafter. CO_2 injection began in December, 1984. The wells in the CMU are completed with approximately 150 ft of 4 ¾-in. open hole; at first, the wells were expected to increase the difficulty of choosing an appropriate placement technique.

The CMU was developed with “chicken wire” patterns, or a diagonal line drive in which producers and injectors line up along the WNW to ESE fracture trend. This development has led to many injectors communicating directly to the offset producers, which became even more evident when CO_2 operations began in late 1984. Because of poor conformance results, the former operators began controlling gas breakthrough by reducing the gas-injection rate and altering the gas-to-water ratio (GWR). If these changes failed to control the gas volume being produced, the offending injector was then put on continuous water injection. A study conducted indicated there possibly should be pattern realignment, which could have been a longer-term solution to the conformance problem despite its expense.

The current and previous operators of the CMU and SEU used sound engineering and operational practices for developing and maintaining the property. As a result of numerous engineering, geological, and petrophysical studies, significant operational and development changes implemented at the CMU had included (1) infill drilling programs, (2) conversions of producers to injectors, and (3) the implementation of CO_2 flooding. Therefore, it was deemed that any improvements in this unit’s performance would be achieved by implementing technology that had not been used before, and would represent a step-change in operations. Unsuccessful attempts over the past 5 years to reduce the amount of CO_2 breakthrough have been the main focus of all conformance treatments.

In 2001, reviewing the production history, projected unit life, the then-current operations, and expenses indicated that improved oil recovery and reduced operating expense at the CMU could be achieved by applying conformance technology. Conformance technology has been implemented to increase oil production through improved sweep efficiency, and to reduce operating costs by reducing the amount of CO_2 cycling between wells without hydrocarbon displacement. Currently, the evaluations have continued to indicate that an improved oil recovery and reduction of CO_2 breakthrough without benefit can be addressed.

TEAM STRUCTURE AND ITS EVOLUTION

The team concept and the open-door process that were established for addressing conformance issues in OPL unit projects have been modified very little during the past 6 years. Most of the engineers have remained the same as in the first assigned group that was chosen. Key to the team structure was an ongoing learning and training process that mentored many engineers and operations personnel within both the OPL’s and Halliburton’s ranks that were brought into the phases and processes during the workovers. Developing specialized core teams for addressing conformance issues had been an ongoing effort by Halliburton and the currently aligned and merged OPL operations. Halliburton had developed this concept over the last 15 years with various operators – some of which were predecessors of the current OPL operations.

The conformance team’s goal was to lower gas production, thereby lowering gas-processing fees, and to develop a program that could be used in OPL’s other floods. Additional benefits would be increased oil production, possible reserve growth (flooding new intervals), and longer economic viability for the floods because of the reduced gas production and increased oil production. This goal has not changed and is used as the focus for the continued success into the future.

The original conformance team included members with expertise in reservoir, production, and operations engineering in addition to diagnostic, solution, and treatment design engineering. The Halliburton functional groups interacted in an environment that crossed boundaries of the various experience areas. As knowledge was gained, data and details recorded have been used. Continued success has depended on the creation of solutions that fit the needed criteria discovered during the project’s ongoing work and treatments.

Initially, each of the initial team members was given specific project task(s). For the first year, planning meetings were held throughout the candidate-identification phases, and all discussions were approached as if everyone worked for the same company. Once more knowledge was constructed detailing the needs and processes that could make a change in the reservoir performance, the team was reduced to only the personnel needed to undertake the work.

Initially, the analysis, design, and implementation of the conformance technology were performed with an OPL/Halliburton core team that consisted of members in these skill areas:

- An OPL production engineer (located in the field).
- Halliburton reservoir engineer (located in the area).

- Halliburton conformance specialist (located in the area).

This core team was initially supported by the following additional team members:

- OPL reservoir engineers.
- OPL geologists.
- OPL team leader.
- Halliburton project leader.
- Halliburton account leader (located at the OPL field location).
- Halliburton field engineer (located at the OPL field location).

The current team structure consists of:

- An OPL production engineer (located in the field).
- Halliburton conformance specialist (located in the area).
- Halliburton account leader (located at the OPL field location).
- Halliburton project leader.

In its initial effort, the OPL's goals for improving the operation unit consisted of these tasks:

1. Performing data acquisition processes using the in-house data collection computer system using proprietary software.
2. Acquiring a proper understanding of the reservoir using a combination of the production and injection montages, their reservoir model's predictions, and the well parings performance.
3. Identifying and prioritizing conformance problems based on performance and observations. Operator collected data using a technique where the throughput analysis and pressure transient evaluations indicated high-priority needs to identify the well pairs with undesired performance.
4. Developing knowledge and understanding from historical data giving real-time performance and not the masked performance caused by changes in reservoir pore pressure developed over time to gain CO_2 miscibility.
5. Determining and performing diagnostic tests for capturing additional data and descriptions. This technique of performing multi-rate injectivity analysis per profiles was very instrumental in identifying the magnitude of fissures or fractures into the reservoir and near wellbore conditions of the reservoir entries.
6. Analyzing the historical data, diagnostic tests, and analysis performed to identify problems. Reflection time needed to gain an understanding of the occurrences that have led to the physical conditions of the reservoir structure and its integrity, loss of integrity, and matching fluid movement to predictions, were developed.
7. Determining the required attributes and criteria needed by a solution process. Based on knowledge, new solutions have been created that are tailored to successfully address the identified needs and required placement techniques.
8. Diagnosing and analyzing the necessary placement controls. In developing a solution, it needs to have the capability to successfully place it at the right part of a reservoir without becoming an obstruction to beneficial production and fluid displacement.
9. Choosing and designing the proper conformance solution based on the needs of the subject wells. Solutions having properties such as (1) liquid systems with in-situ polymerization post placement, (2) fibrous materials giving a flexible blockage, (3) crystallized copolymer systems capable of entering and modifying highly leached out and fissured/rapid fluid transient fissures and fractures, (4) reactive chemicals with both internal and external catalysis, and (5) high strength/highly efficient displacement materials capable of blocking off or modifying fracture systems with rapid communication between well-pairings.
10. Initially applying the developed conformance solutions to a pilot group of wells, then proceeding to the next, then the next, etc.
11. Performing post-treatment evaluations for modifications or changes in well performance. An effort to reflect on what may be discovered and learned without making assumptions was incorporated into the focus.
12. The team members' reviews of the production history, projected unit life, current operations, and expenses indicated that improved oil recovery and reduced operating expenses could be achieved by applying conformance technology to the CMU. By reducing the amount of CO_2 cycling between wells, oil

production could be increased (through increased sweep efficiency), and operating costs could be reduced. To measure the results of this work, the team analyzed the project according to the reservoir rather than by an individual well perspective. This same focus is being conducted today and is planned to extend into the future.

The information and understanding gained from the pilot wells in this unit were reported by Creel, Honnert, Tate, et al.[1,2] The discoveries and successes or failures were used to fine-tune the conformance analysis process for applications on the remaining CMU and SEU conformance problems. This process has been maintained and also used to build projects in other operations' units throughout the world. "Best Practice Processes" have been applied to other OPL units' conformance candidates and have helped train additional OPL professionals to address conformance problems.[3-5]

The initial process of using a core team of professionals with open access to all available data was a key to gaining rapid successes and understanding of what is needed and what will work to fix the problems. All results have been captured to serve as quantitative evaluations and quality control assessments. This process is what is being used to give this updated report.

Both pre-job and post-job treatment data are available to Halliburton so that the results can be analyzed and score-carded, and areas of improvement can be identified. Areas that do not need to be changed are identified as "best practices."

The initial approach used the fully integrated services and operation capability to remedy undesired well and reservoir behavior. It was confirmed that the majority of past conformance-treatment failures in the unit were linked to the following problems:

1. The "conceptual image" of the reservoir may have been incorrect or outdated.
2. A vendor may have tried to "force fit" an available product without regard to the problem that was being addressed.
3. The placement technique was inadequate for the completion method or did not include needed control parameters.

The conformance team's charter, remaining unchanged through the project life:

1. Start each well or pairs of conformance wells with a clean slate and develop a conformance solution for them.
2. OPL's files were opened to the Halliburton members who may review well histories, reports, workover histories, engineering reports, and interviewing personnel.
3. Archive data electronically for rapid storage, access, and cross-referencing.

Halliburton policies are as follows:

1. Open-door policy and full disclosure on evaluation methods, diagnostic procedures and processes, placement technologies, solution qualifications, performance data, design software, and procedure development methods.
2. Research and technology sharing between OPL and Halliburton along with associations enhanced each company's ability to approach the undertaking. Synergy among internal and external groups opened communication and data links.

The following critical items are required in this shared environment:

- Engineering and/or geological studies: Reservoir descriptions and drive mechanisms.
- Maps of the unit: Well, structural, and isopach maps.
- Data files: Files containing all well information, well tests, and production and injection information.
- Montage plots: Production and injection plots with at least the last 5 years of production or injection history. Scales in time, pressure, and rates the same on all plots.
- Type logs: Logs with formation tops on subject producing interval and additional geological markers shown.
- Total unit production and injection plots: Plots showing when wells were added or deleted, and the start of water and CO_2 injection (if applicable).

- Individual production and injections plots: Plots on all wells for the same time period.
- Areal and volumetric sweep efficiency evaluations.
- Mobility ratios and injection/withdrawal ratio (IWR).
- Water cut and water-oil ratios.
- Operating costs: Lifting and water disposal costs.
- Data availability.
- Cores, relative permeability (K), SOR.
- Montage analysis.
- Test results: Tracers, profile and temperature logs, production logs, pressure surveys, pulse testing, etc.
- Production data: PC-driven production analysis programs simplifying and improving production data-sharing capabilities.

For analyzing the entire CMU and SEU, historical oil, gas, and water production data have been gathered for each producer, and historical injection rate and pressure data have been gathered for each injector. Production and injection data have been entered into digital spreadsheets for analysis, and plots of the production and injection data have been prepared for each well. Montage plots, which show the individual well injection and production histories in relationship to the actual location of the wells, have also been prepared. All available core data and injection profile tests have been reviewed. To maintain integrity within the project, the efforts to maintain a detailed data collection and a follow-up to gain knowledge from the data has been the guidance directive.

PROBLEMS AND RESERVOIR CHARACTERISTICS

The San Andres formation in this unit is characterized by multiple layers with discontinuous areas caused by widespread impermeable layers. Most of the current recovery in the Central Platform is attributable to pressure maintenance through water floods and miscible floods using CO_2. The permeability contrasts found within the various layers are responsible for the varying effectiveness of water and CO_2 injections. The unit development had led to many injectors communicating directly to the offset producers. This became even more evident when CO_2 operations began in late 1984.

By studying the montage plots, team members have identified multiple injectors having CO_2 injection cycling problems with one or more of their offsetting producers. The direct communication between injectors and producers is referred to as CO_2 cycling and appears as a very rapid spike in gas-production volumes in the producers shortly after the CO_2 injection cycle starts in the communicating injector. This increase in gas-production volume is usually accompanied by a decrease in oil-production volumes.

As set up in the original plan, the conformance team uses various piloted area studies to implement conformance technology rather than a “shotgun” approach. Reservoir characteristics, technical and mechanical capabilities needed, operation’s requirements, and political environments were and continue to be only a few of the driving forces. In addition to these forces, the available resources and funding provided strong motivation. Continued success in reduction of CO_2 breakthrough without benefit gives the funding to continue the project.

The following guidelines were used for determining the initial areas with the best potential for pilot studies:

- High probability of success.
- Able to translate results to other areas.
- Operation’s internal communication.
- Return on investment potential.
- Amount of geologic/reservoir data available.
- Good Halliburton and OPL relationships established.

Team focuses also affected piloted areas by reducing water production and breakthrough CO_2, and by reducing costs in the following areas:

- Maintenance.
- Corrosion.
- Separation.
- Re-injection.

- Equipment replacement.
- Facilities optimization.
- Workover (paraffin, acidizing, remedial workovers, etc.).
- Disposal.
- Regulation.
- Environment.

Operations personnel continue to try to interfere as little as possible in the patterns during the analysis so that all the changes can be attributed to the conformance work. Team members understand that some results can be very quick, such as reduced gas production within a cycle. Other results will probably be long term, since the oil from newly swept zones could take several months to reach the producing well, and the gas being redistributed in the pattern can take time to influence other wells in the pattern.

The Conformance Team developed criteria for initially measuring project success. The high operating cost and low profit margin typical of the Permian Basin required a closely aligned goal and reward structure. This unique project was especially involved because of the required purchasing, producing, recovering, and re-injecting the CO_2 on the CO_2 WAG. Corrosion of tubulars also often becomes a factor in the WAG floods. These factors were compounded by the oil price slump of 1998 and 1999, when the wellhead price reached a low of $9.00. Currently with oil @ ± $55 – 60 per bbl with a peak last year of $70, the project is exceptionally favorable.

This project continues to involve data analysis, reservoir and production engineering evaluations, solutions proposals, and a thorough review of OPL's economic drivers in pattern reviews. In this mature unit, the potential for major impacts on recovery and production rates and cost reduction had become an important factor. Close alignment, with priority given to cost issues, was necessary for initially implementing this project and has remained so during its life.

With these understandings, the 6-year history in performing conformance treatments has shown to be beneficial and economically favorable to the operation. The team's solution techniques have indicated that a continued effort is feasible.

CANDIDATE SELECTION – STARTING A PROJECT FROM HISTORICAL TO DIAGNOSTICS

The history of the units and factors contributing the units' status have been studied. The sequence of events such as initiation of waterfloods, WAG flood, and infill drilling have presented a timeline that could be related to the production history and cumulative recovered volumes.

These anomalous areas have been evaluated on a pattern basis, which includes injectors and producers. This method yields a reservoir evaluation instead of an individual well evaluation, which can be influenced by mechanical or near-wellbore problems. The resulting recommendations and proposals 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 along with the linkage to the montage analysis.

A second analysis tool involves the use of tabulated production rate and cumulative recovery data. The areas and wells identified by the montage analysis are reviewed to verify that production can be improved by modifying sweep in that area and/or by reducing interwell communication. The gas injection and production rates are also evaluated to determine if reducing CO_2 rates to values that are more typical for the field can reduce costs.

Wells are then selected for treatment according to a prioritized list of injector/producer pairs or combinations of associated wells that result from the analyses described previously. These wells are reviewed again to eliminate those with known mechanical problems, and a diagnostic program is generated.

Montage maps allow team members to identify areas where the reservoir has direct fluid communication from injectors to producers. The montage maps are groups of history plots of individual wells (production and injection) shown at a reduced scale and positioned on a large background. The plots are arranged as the wells are physically located in the field. This presentation makes both the time and spatial correlation of events in injectors and producers straightforward. For example, if a producer has a marked increase in gas production, the engineer can quickly identify a corresponding initiation in a CO_2 cycle in an injector in the area.

After the conformance candidate selections are made, injection profiles are then obtained on the subject wells before a treatment is designed. Multiple injection profiles are run on each subject well under normal operating conditions, as well as at reduced injection rates and pressures. These survey logs are obtained on both the water and CO_2 cycles to determine whether injection is entering the same intervals regardless of the injection fluid. These injection profiles are used for designing and placing the conformance treatments, which are tailored to each well's requirements. For one particular subject well, the conformance treatment was undersized to keep initial costs low and to allow the effects of various treatment parameters to be shown. The initial understanding was that some treatments might need to be repeated later to contact additional unswept portions of the reservoir.

A network data collection system allows team members to monitor the candidate pilot wells (both production and injection) and to capture information, evaluations, and results. Post-treatment injectivity is analyzed to determine modifications in entry profiles. Offset production wells within the determined patterns are evaluated for changes in production.

PROBLEM IDENTIFICATION AND DIAGNOSTICS – THEIR RELATIONSHIP

Team members are continuing to use the Problem Identification and Diagnostics phase by accurately identifying the problem(s) occurring in the reservoir. Reservoir description expertise is still used to gain an understanding of the unit's reservoir, as more data and performance becomes available. The first and most important step has been to identify the problem's source. Team members also try to foresee potential problems so they could be prevented or minimized.

Team members have continued to determine that problem identification tasks should be performed to minimize or eliminate future well-management problems. These tasks include gathering information about the reservoir, simulating its future behavior, and treating it. To understand the source or potential source of a problem, team members thoroughly investigate the following well and reservoir parameters related to the recovery mechanism.

- Reservoir permeability and porosity.
- Permeability anisotropy and heterogeneity.
- Relative permeability to oil, water, and gas.
- Net formation height.
- Portion of productive interval completed.
- Location of all perforations or openhole completions.
- Reservoir dip.
- Original water-oil and gas-oil contacts.
- Connate water and irreducible oil and gas saturations.
- Location and continuity of shale, anhydrite, or other low-permeability layers.
- Oil-, gas-, and water-production rate histories.
- Location of fluid entry and the type of fluid entering the wellbore.
- Wellbore integrity and cement bond log evaluations.

Not all of the desired information has been or is always available for evaluating the conformance problems thoroughly.

GATHERING DATA – DISCOVERING HIDDEN FEATURES AND PAST PERFORMANCE

After completing each thorough engineering analysis, team members review individual well production and injection histories for all the unit wells. The OPL files of past evaluations, workover projects, and injection profiles are reviewed for determining the further diagnostics needed to better understanding the existing problems.

Diagnostic analysis is conducted on the candidates that display a performance loss according to the candidate-selection criteria. The source of ongoing problems is researched by conducting multi-rate injectivities using the gas-injection and water-injection phases, and by performing profiled entry analysis.

The multi-rate injection profiles are run on the wells during both their water and CO_2 injection cycles for determining reservoir entry variances. Any lack of offset responses during the multi-rate injection tests is also evaluated. By using the range of injection rates with each corresponding bottomhole injection pressure (BHIP), identifying intervals that are taking most of the injectant up to the point of fracturing pressure are noted.

Project engineers need to understand where the fluids have gone at different conditions. The conditions that vary are the pressure changes associated with different injection rates and the variations in injection profiles. These 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 provided 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 BHIP does not exceed the fracture gradient. The focus is to determine if entries vary at the different rates and accompanying changes in BHIP (if any) on each injection phase (water and CO_2).[6]

A tracer company was rigged up on wells to perform intensity and velocity shot analysis and temperature evaluation. A base gamma and analysis gamma were always recommended for comparison. The ability to take up to five shots per run was usually set up. An injection unit was rigged up that was capable of accurate rate and surface pressure measurements. Availability of sufficient injectant water or CO_2 was arranged (usually 250 to 500 bbl). The well's current production or injection rates were used to address the starting points of injection.

Variances of entry into the reservoir were analyzed, and limitations were also determined for the placement technique. The solution's criteria and attributes were established from the injectivity evaluations.

Along with determining the extent and condition of the problem, an opportunity can exist for determining the criteria a treatment solution must fit and the placement techniques that should be used. A ratio for dual-placement control may be planned for selectively placing some of the treatments. Maximum injection pressure can be determined for bullheading the treatment fluids based on the communication problems identified. Differential pressure responses may indicate the tortuosity 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 0.1 to 230 md in the unit's Permian Age reservoir, there is little chance of injecting a gelled fluid at the placement rate determined from each of the multi-rate injectivities at matrix flow. This analysis helps investigators determine if a treatment should be placed where it develops a blocking and diverting effect without entering other undesired portions of the formation. If investigations show that a specific pressure developed from varying injectivity would cause undesired entry, this information can be 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.

One of the largest problems confronted was to define injectivity entries and interwell communication aspects based only on the multi-rate testing and having the influence of the reservoir pore pressure that had been increased by choking back production since the CO_2 flood was initiated for miscibility. Unless the historical files giving the details were reviewed often, missed features were assumed. Wells may have historically been injected at exceptionally high rates at several hundreds of barrels per day at extremely low pore pressure. The nature of the architecture that accepted these high rates of injection were mostly fractures with a characteristic of being leached out and eroded from years of water being forced through these structures. With the reservoir pressure increased to a desired pore pressure, multi-rate injectivities with profiles could see the features, but the pressure responses were "masked" and hidden because of the artificial pressure maintained on the reservoir. Assumptions would be made that the problems lay within a permeability feature and not those of a fractured system. Descriptive problems were used to determine the criteria of solution properties, and with a missed diagnosed feature, operations could pick the wrong technique and product to address the problem.

SOFTWARE FOR CORRELATING PROBLEM IDENTIFICATION

Identifying problems requires that investigators analyze and interpret the available information. One tool that has been used for this analysis over the 6-year period is Halliburton's computerized water-control "expert" system.[7,8] The expert system uses artificial intelligence techniques to help identify the problem, select the proper fluid system, and recommend a treatment design based on results from built-in engineering calculations. The problem-identification phase of the expert system infers the most likely problems from the available data, displaying a confidence level for each potential problem. The program will notify the user if additional data is required. Some analysis was performed with a Black Oil multiphase/multi-fluid reservoir simulation via the model QuikLook.

Some of the following determinations are being made in the project analysis and shown to match former identified problems during the project period.

CHANNELING THROUGH HIGHER PERMEABILITY

High-permeability streaks can allow the fluid (water and CO_2 WAG) that is driving hydrocarbon production to break through prematurely, bypassing potential production by leaving lower-permeability zones unswept. Possibly, as the driving fluid sweeps the higher permeability intervals, permeability to subsequent flow of the fluid becomes even higher, and can lead to increasing water-oil or gas-oil ratios throughout the life of the project.

Channels can be detected through tracer surveys, interference and pulse testing, reservoir simulation of the field, reservoir description, and reservoir monitoring. Tracer surveys and interference and pulse tests verify communication between wells and help determine the channel's flow capacity. Reservoir description and monitoring verifies the location of fluids in the various formations, with reservoir monitoring tracking the fluid movement. The reservoir description data allows more accurate modeling of the formations, which therefore allows more accurate modeling of fluid movement through reservoir simulation. Additional sources of information include coring and pressure-transient testing of individual zones to determine permeability variations between zones.

Possible changes in actual permeability are noted and believed to be from the erosion and leaching of the formation rock by water and CO_2. Pressure transients indicate a greatly increased permeability in various layers that have historically shown to be where the bulk of injection has traveled over the life of the floods.

FINGERING

Unfavorable mobility ratios (>1) could allow the more mobile displacing fluid (from either the primary or enhanced recovery operations) to finger through and bypass large amounts of oil. When breakthrough occurs, very little additional oil will be produced as the drive fluid continues to flow directly from the injection sources to the production wells.

Information on reservoir and drive fluid mobilities drawn from fluid and core data were important for determining whether fingering was a potential problem. Reservoir simulation and available information on ideal systems were used for determining whether the sweep efficiencies were within the expected range if no fingering occurred. Reservoir monitoring was used to identify the possible position of the fluid interface within the reservoir and to help determine whether fingering was occurring.

Follow-up revisions to the reservoir model and fine-tuning the characterization were built on to better fit the performance and discoveries made from the diagnostics.

FRACTURE COMMUNICATION BETWEEN INJECTORS AND PRODUCERS

On wells where identified problems consist of fracture and vugular communications aspects, treatments using a crystallized copolymer system (CP) have been performed. These materials have been also used in other nearby units to address fracture and fissure communication to stop these highly communicating features from thieving most of the injection and transmitting almost directly into offset producers.[9] The crystallized copolymers are resistant to degradation by CO_2 and bacteria, and have a temperature range of 70° to 240°F. Placements may be made down current injection tubulars working rigless, a practice that can save expense by avoiding the need for a workover unit. Removal of the crystallized copolymer may be obtained by reactions from bleaches or oxidizers.

Poorly oriented hydraulic fractures can also provide channels that allow injected fluids to bypass much of the hydrocarbon production. Although created fractures rarely interconnect two wells within this unit, a hydraulic fracture still could provide a channel of higher conductivity that would allow much of the reservoir fluid to be bypassed. Preferred fracture orientation and the possibility of enhanced recovery operations were considered in the initial development of this reservoir.

Various technologies, such as microfrac analysis and an anelastic strain recovery, could have been used for determining the expected direction of fracture growth within the pay portions. If the lengths and direction of any hydraulic fractures were known, reservoir simulation could be used to model flow through the system and determine the expected sweep efficiency.

SOFTWARE IDENTIFIED POTENTIAL PROBLEMS

The fuzzy logic software employed by the project helped team members identify potential problems with the reservoir, as listed below.

In 100% of the wells, interwell communication presented problems that were manifested in various ways:

- Interwell tracer.
- Pulse test.
- Fracture communication in relation to well spacing.
- Permeability profile in relation to well spacing.
- Natural fractures in relation to well spacing.
- Injection pattern.

In 64% of the wells, high-permeability streaks caused difficulties.

- Production or injection profile.
- Interwell tracer.
- Drive mechanism.
- Natural fractures.
- Injection pressure.
- Maximum injection pressure.
- Fracture-stimulated well.

Fracture communication based on older historical events caused trouble in 20% of the wells.

- Interwell tracer.
- Natural fractures in relation to well spacing.
- Fracture communication in relation to well spacing.
- Pulse test.
- Acid and fracture treatments performed on original completion

SOLUTION DEVELOPMENTS AND THEIR PLACEMENT SELECTIONS

Historically, the initial assumptions made by many operators are that values can be obtained from analyzing problems or needs, but are often not considered when solution treatments are applied. Ideally, operators perform diagnostic tests to correctly interpret problems and develop necessary criteria and requirements. The required attributes for a solution on the initial and the following wells on the project were defined according to desired parameters of need. The available solution’s limits, qualifications, and “ability to place” have been developed accordingly. The Conformance Team has matched the best solution system or techniques to meet the necessary attributes required and provide the most favorable economics for each well or pairs of wells treated.

Initially in 2000, industry solutions used in conformance would vary from cement systems to gel technologies. Ideally, when problems are diagnosed, a solution that would be most practical to apply, with a wide variety of properties, usually leads to best success.[8] Initially and through the emerging project, some of the following solutions have been scrutinized.

- Cements.
  - Conventional or foamed.
  - Microfine.

    - Diesel oil based (conventional and microfine).
- Polymers.
    - Organic and inorganic.
    - In-situ polymerizing monomers.
    - Sealants and mobile sweeping.
- Silicate-based gel systems.
- Relative-permeability modifiers.
- Tools and techniques.
    - Casing liners (fixed and expandable).
    - Packers and bridge plugs.
- Unconventional solutions.
    - Sand.
    - Asphaltenes.
    - Crude oil.
    - Hydrated crystals of copolymers (super absorbents of a variety of sizes).
    - Filtrates of silicates.
    - In-situ generating scales.

Solutions have been based on the extremity of required placements and the proximity to the wellbore. Some of the potential problems to be considered 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).

CMU AND SEU SOLUTION CRITERIA–BUILDING TO FIT THE NEEDS

Using the continued identification of losses of flood efficiency and the identified communication problems, the necessary solution criteria were determined. The solutions needed to be capable of accomplishing the modifications needed in the most economical manner.

The diagnostics injectivity analysis has continued to set the criteria for the solution material on these wells, with the exception of finding the “masked” wells – so referred to because the features may be hidden by artificial pore-pressure support. Most of the treatments that have been performed are at a precise injection rate, usually without any pressure increases, to gain entry only into the problematic intervals. The treatments have been placed at deep depths to negate the re-emergence of injectant back into the communicating intervals. Having an option of doing segmented treatments based on post performance has helped ensure that a conservative approach and economic justification are fulfilled.

Criteria for the solutions used on the project follow:

- Capability of influencing fluid flow for a long term in either injection or producing wells by achieving deep penetration into the formation with the material on permeability controls.
- Some solutions that can be placed into the pathway of water and CO_2 travel without resistance because of fluid interaction, viscosity, or pre-developed polymer gel chains.
- Some solutions that consist of a non-solids fluid that will attain greater viscosity (sometimes infinitely greater) in a controlled period of time after placement.
- Solutions that can withstand the degradation of extended contact with CO_2.

- Solutions inert to the degradation of bacterial growth.
- Solutions that can be placed under current tubulars in wells without a workover unit.
- Some solutions that are not externally reactive to formation fluids and have a predictable reactivity to internal activation catalysts.
- Solutions that demonstrate either mobility or up to a high resistance to extrusion once their final viscosity is obtained.
- Solutions that can withstand the occurrence of intermixing with produced water or CO_2 because of crossflows.
- Solutions that can be removed if necessary.
- Solutions that can be placed in segmented treatments.
- Solutions that can be placed in crystal form on problems showing fracture communications.

CMU AND SEU SELECTED SOLUTION SYSTEMS

Channeling through Higher Permeability and Fingering

The gelation system selected (an in-situ generated polymer [IGP] system) has been pumped as a water-thin fluid into the rate/pressure controlled isolated communication path's permeability. The wells treated with these solutions were then shut in to allow polymerization into an elastomeric gel. The IGP system uses a temperature-activated initiator to induce a phase change from a liquid to a solid at predictable times. The solution system is an environmentally acceptable conformance-control product that avoids the use of metal crosslinker. It is an acrylate monomer that is acid-resistant and compatible with CO_2 environments. Monomer concentration and initiator selections were based on identified reservoir and injection temperatures.[7,8] The system was mixed by batch blending and then pumped into the formation at rates based on the diagnosed parameters. The system uses a temperature-activated "azo" initiator to induce a phase change from a liquid to a solid at predictable times. The temperature range for this system is 70 to 200°F, which fits into the unit's temperature of 115°F.

The Conformance Team researchers and decision members have considered and rejected a number of treatment options over the project's operation. Metal-crosslinked polymers were discounted because of their inherent viscosity and a suspected compatibility of the crosslink mechanism to CO_2 exposure. Silicate systems were excluded because of their uncontrolled, rapid gelation in a low-pH environment and because of their interaction with divalent salts in the formation brine. Cement squeezes were rejected because, at best, neither conventional cement nor the small-particle microfine cements could penetrate the formation's permeability. The IGP system was selected to seal off the high-permeability communication streak. The nonionic IGP system was chosen because it enters the formation as a water-thin monomer solution but polymerizes in-situ into a stiff, resilient gel.

Another factor that influenced the selection of the IGP system was its expected non-reactive response to the low-pH environment created by the CO_2 injection, the reservoir brine or crude oil, and the formation's lithology. Moreover, the IGP system incorporates a thermally controlled activator. These properties contribute to a fluid system that injects as easily as water and does not divert or react prematurely during placement.

The principal components of the IGP conformance-control system are a low-toxicity acrylate monomer and a thermally controlled "azo" activator. The formulations selected for the candidate wells consisted of a leading solution of viscous polymer followed with a strongly crosslinked, ringing gel.

A minimal volume of 2,000 gal of a treated 2% potassium chloride (KCl) preflush solution containing an oxygen scavenger was injected ahead of each treatment. The same 2% KCl solution was used to displace the IGP out of the tubing and into the formation. Each treated well was injected with a specific volume of IGP based on the fuzzy logic computer program evaluations. The IGP was batch-mixed in a clean transport and initiator was added just before pumping.

FRACTURE COMMUNICATION BETWEEN INJECTORS AND PRODUCERS IN THE CMU AND SEU

On wells where an identified problem consisted of fracture and vugular communication aspects, they were addressed with a crystallized copolymer (CP) system. Crystallized copolymers are water-swellable but not water-soluble, 100% crystalline synthetic polymer. They absorb hundreds of times their own weight in water ranging from 300 up to 800 times based on their particular grind, carrier and present aqueous fluid, and the specific manufactured base material. These CP materials were intended for use primarily as a lost circulation material and to address near wellbore remediation problems and reservoir architectural features needing modification by cementing methods and loss circulation materials (LCM). These materials have been used successfully to address fracture and fissure communications in wells in nearby units to stop these highly communicating fracture features from thieving the majority of injection and transmitting almost directionally into offset producers.[9]

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).

Crosslinking 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 cross linked 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, then to the chopper where it is cut to a specific size and bagged. The crosslink process will help keep it insoluble.

The crystallized copolymers are resistant to degradation by CO_2, bacteria, and temperature below 250°F. Rigless placements down current injection tubulars were used at a savings by not requiring a workover unit. Removal of the crystallized copolymer, if needed, was obtained by reaction with bleach or oxidizer generally placed with a coiled tubing unit.

The Conformance Team researchers and decision members have also considered and rejected a number of treatment options to address the fractured features in communication. Metal-crosslinked polymers were discounted because of their suspected compatibility of the crosslink mechanism to CO_2 exposure and low capability to control the flow through fracture systems without a large volume being placed and sheared to pack off the high flow potential within these features.

Cement squeezes were considered as an option if the fracture feature was identified as potentially very open and not tortuous. Foamed cement would be selected if concerns on influxes and displacement efficiencies were noted.
The time in which the crystallized copolymers will start to hydrate is over 20 minutes if in fresh water and at temperatures less than 100°F. Use of produced brines (8.9–9.2 lb/gal) will have a delay of around 45 minutes before the crystals hydrate. Placement may be defined around this feature. Once placed into the injectant stream (normal injection water), the wells may be closed in for a period of 3 to 6 hours to allow the crystallized copolymers to thoroughly hydrate and swell. The material will swell from 100 to 800 times its crystal weight in fresh water and 50 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. 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. The crystallized copolymers, like all copolymers, may be removed on contact with oxidizers or bleach solutions whereby its backbone is broken and it becomes water-like.

Treatment volumes were adjusted per ongoing injection and placement trials. 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 would indicate changes. An extended and changed pressure decline would indicate enough material had been placed. The wells were then placed back onto injection for analysis and performance testing.

PLACEMENT TECHNIQUE HISTORIES

Based on our research and history of performing conformance treatments requiring various techniques to guarantee the right placement, the use of these various means were always considered and not shelved for convenience. While the concepts or premises to fluid control are not new, we continued to consider variable means from past treatments and any ideas we could generate as a means for selecting placement techniques for controls on the fluid movement in workover wells. Designs for the treatments were conducted using the fuzzy logic computer program to determine the appropriate solutions, proper techniques, and treatment volumes.

Historically, placement technology has been determined from the performed diagnostics. Treatment procedures on the injection or production wells depended on understanding aspects of the available data and analysis, fluid selection and the desired results, pressure and rate relations and limitations, and reactivity to internal and/or external activation with its consequences.

Some techniques considered for placement of the conformance treatments on the projects were:

- Bullheading – Using the current tubulars and relying on rate/pressure determinates. The established rates in injecting a solution with the same physical properties as the normal injectant and traveling into and along the same paths deemed undesirable were followed by the remediation solution. Ideal to this method is that the similar solution will gain entry and placement suitable to then react and give a resulting diversion and blockage of undesired fluid movement paths.
- Mechanical packer placement technique – Using a packer to isolate perforations or a portion of an openhole completion into which the treatment is to be placed. This means would be chosen if the mechanical packer was needed to control fluid placement and interference or losses.
- Dual placement – Interfacing of compatible solutions, separation by each component's rate. If diagnostics indicated, this method would be used to gain placement and control. Dynamically, the interfacing of fluids can keep placement separated via rock losses.
- Controlled interface – Using dual-placement with downhole-logging instruments to define entries controlled by component rates was often reviewed if the diagnostics indicated this technique would be required to separate and protect entries.
- Transient placement method – Using crossflow potentials to help eliminate entry into unwanted intervals while injecting into the desired zones to be sealed off did not have to be used because we did not encounter the potential of crossflows on wells treated.
- Equipment usage – Using options such as coiled tubing to enhance placement techniques by giving another controlling device to address dual control, a flow-isolation technique, and transient placements were always a consideration if complexities arose in the diagnostics. Many wells treated to change injectivity patterns were post-treated using coiled tubing and pulsation-wash tools injecting acids and solvents to clean out apparent scale and paraffin damage from years of injection and apparent damage on most of the exposed perforations or open holes. Treated intervals were stable with this workover technique due to the stabilization and resiliency of the solutions used in the project.

CMU PLACEMENT TECHNIQUES

Bullheading Treatments – Eroded Permeability

Diagnostics and investigation into each well's injectivity determined that usually a bullhead placement technique could be used with the current injection tubing strings. Treatments were performed with the fuzzy logic computer program-designed volume of in-situ polymerizing monomer based on well spacing, injection rates, and the time to breakthrough. The ability to place an in-situ polymerizing monomer without a delta-pressure response was affected by its waterlike viscosity. Pressures monitored during the placement of treatments varied less than 3 psi. When the later portions of in-situ polymerizing monomer system were placed, they polymerized in-situ to form a very stiff, resonant gel. Transition (time between activation of the batch mixed solutions for placement and the final position and polymerization of the IGP) was considered based on the crossflow investigation made during the multi-rate injectivity analysis. Set times required an almost immediate polymerization when the IGP was in place to offset the effect of a possible crossflow. Post-treatment injectivity profiles now indicate that prior crossflow regimes in static conditions do not exist.

Bullheading Treatments – Eroded Fissures and Fractures

Diagnostics and investigation into each well's injectivity may have determined that a bullhead placement technique could usually be used with the current injection tubing strings even when displaying a fracture controlling the movement of fluids. Treatments on the wells determined through historical records indicating most of the fissures and fractures had a major dominance in controlling where fluids traveled were also performed with the fuzzy logic computer program. Treatments were designed with an estimated volume of in-situ hydrolyzing crystallized copolymers capable of swelling up to 800 times their weight in water, based on well spacing, injection rates, and the time to breakthrough. Additional steps of injecting these crystals were made as determined from a pressure transient fall-off post placement affect into the fissures or fractures. The ability to place an in-situ hydrolyzing crystal with a slight delta-pressure response until a timed reaction for hydrolyzing reaction is gained was caused by its slight gel-like viscosity. Pressures monitored during the placement of treatments varied and built, indicating the fissures and fractures were beginning to be blocked off and reduced as loss intervals. Transition (time between mixing and final placement of the batch mixed solutions for placement and the final position and the hydrolyzing body was considered based on the crossflow investigation made during the multi-rate injectivity analysis. Set times required an almost immediate polymerization.

ALTERNATIVE SOLUTION

An attempt to determine if a polyacrylamide metal-crosslinked system could stop waste CO_2 from cycling through eroded high-permeability intervals into offset producers was performed. The one attempt using a metal-crosslinked polymer gel was performed as a trial to determine if these systems possibly could give results to satisfy advisors on the project.

QUALITY CONTROL

Laboratory analysis was performed to determine the set times and viscosity performance for the monomer, crystals, and polyacrylamide crosslinked gel treatments based on downhole injection temperature. The IGP monomer was intermixed with injected water to check for any adverse reaction in set time as a co-test. The crystals (CP) were mixed with a variety of carrier fluids to determine the best fluid for the particular well's placement requirements. The polyacrylamide metal crosslinked gel system was tested for hydration time, crosslink time, and placement capability time.

APPLICATIONS FOR THE SOLUTION SYSTEM

IGP Solution

The IGP system has been used on both injection and producing wells. Its use in some of the projects on this paper was for injectors only. The resulting elastomeric gel served as a sealant in a variety of reservoir conditions, including matrix, natural or induced fractures, vugs, and high-permeability streaks. Additionally, IGP flexibility and sealing capabilities were applicable in a broad array of extreme situations that possibly could be encountered in the CMU and SEU:

- Minimizing waterflood channeling, CO_2 channeling, channels behind pipe, and losses.
- Diverting injection fluid paths from eroded high permeability that had over time been swept of hydrocarbons.

Crystallized Copolymer Solutions

The crystallized copolymer solutions were used on injectors displaying a historical known aspect of having fractures created while using acids and fracture jobs to gain entry into the formations, mostly during the initial workovers when the wells were developed as producers. Historical cases where injection was performed over long-term periods at above fracture pressure were also addressed using the CP systems. The flexibility of the CP system provided the best solutions needed in the CMU and SEU project to address communicating fracture systems.

The capability to divert injection fluid from paths that were extremely eroded and changed from the original high permeability intervals was needed. Over time, these paths had been swept of hydrocarbons and were now becoming vugular pathways with a defined communication referred to as "pipelines between injectors and producers."

Alternative Solution - Polyacrylamide Metal-Crosslinked System

As a test, an attempt to treat a highly eroded permeability interval on one particular injection well was performed. Using the pre-formed metal crosslinked polymer gel gave a pressure build through the placement and following the treatment, the well was placed back on injection. Post-treatment analysis indicated a very short time diversion from the former thief interval, but a quick loss of the system's integrity followed with a return to the original injection profile and throughput of CO_2 without benefit.

PERFORMANCE – 1999 UNTIL 2006

As reported by Creel, Honnert, Tate, *et.al.*,[1,2] the first two conformance jobs were performed on CMU wells 273 and 275 in January 2000. Two additional treatments were placed on other pilot wells (CMU 15 and 274) during the last week of September 2000, and two more treatments were performed in early 2001 (CMU 276 and 279). **Figure 2** shows a plot of the combined production of all six wells. CO_2 injection was reduced by 1.2 MMCFD and gas production was reduced by 0.81 MMCFD while maintaining oil production. These results improved operating expenses by reducing CO_2 purchases and processing fees.

Based on the results of the 2000 work, more wells were selected in early 2003 to perform similar conformance work. In addition to running the normal injection profiles as was done in 2000 the profiles were run at normal injection rates, reduced injection rates and at an increased injection rate **(Figure 3).** These additional runs were made to look for changes in injection intervals because of changes in rates or pressures. It was also decided to run an interwell tracer on the eight injectors surrounding an area of conformance issues. All eight injectors were put on CO_2 injection and the gas soluble tracer was added. The 21 offset producers were monitored and injection breakthrough occurred in two offset producers within 11 days of the tracer being added. All producers were monitored for 3 months and additional breakthroughs were observed. All breakthrough pairs identified by the tracer study were the same as had previously been identified using montage plots **(Figure 4)** and conformance plots **(Figures 5 and 6).** A montage plot is a plot of an area with the producers and injectors arranged spatially as in the field. This enables one to look at an area and easily spot problems. The conformance plots have the injector and producer on the same plot which enables one to find the offending injectors. **Figures 7 and 8** show a typical pattern plot which shows all the wells that are affected by the treated injector. From these results, four jobs were pumped in late December. **Figure 9** shows the results of the 2003 work. This work reduced CO_2 injection by 2 MMCFD and gas production by 1 MMCFD while reducing the oil decline rate.

After reviewing the 2003 results, monies were added to the budget to do 22 jobs in 2005. Ten jobs were actually completed in 2005 in Central Mallet. The results are shown in **Figure 10**. The dramatic change in both injected and produced fluids can easily be seen on the plot. Also, there was a flattening of the oil decline. With the success that was being see in CMU, five jobs were performed in the Slaughter Estate Unit [SEU], a nearby CO_2 flood in the same reservoir. These jobs were the first work of this type performed on SEU. The results have been very promising (**Figure 11**) and more work is planned.

As a result of the new OXY Permian contract with Halliburton, we are designing jobs more on technical needs than on price of materials which has increased the volume being pumped two or three times for approximately the same price as the 2000 work. The work done on both leases in 2005 reduced gas cycling considerably. Injection into the offending injectors was reduced by 8.2 MMCFD and the associated produced gas dropped 4.2 MMCFD while maintaining oil production in the affected patterns. This work had an estimated 7-month payout. This work has also freed up CO_2 for use in other patterns that were not cycling gas, freed up gas-processing capacity at the plant, and reduced well failures. All of these have reduced the operating expenses for the lease and operator.
Monies were included in the 2006 budget for conformance on both of these leases and to date seven jobs in CMU and three in SEU have been completed. CMU has another 27 candidates for treatment and SEU has 12 more candidates. The goal is to complete this list by year end 2008. **Figure 12** shows two maps of CMU with the patterns highlighted by the year the work was done. The individual well that was treated has a red circle around it.
Figures 13–15 show examples of the treatment processes that were performed using IPG and CP materials.

CONCLUSIONS

As a follow-up to earlier papers,[1,2] it can be reported that the conformance selection process has continued to be fine-tuned and tailored to meet newly discovered problem aspects and also has been the foundation to determine application and capability of new product developments with the work at the CMU and SEU. Based on the original successful results from the pilot wells, the time required for the various steps in the evaluation process have been reduced over the past 6 years. The initial process of using a core team of professionals with open access to all available data was a key ingredient. All results have continually been captured, and both pre-job and post-job treatment data are available to Halliburton so that the results can be analyzed and prioritized. As a continued process, areas of improvement have been identified, and areas that need to be changed have been worked on.
The timeline and functional process that was originally developed and diligently followed to answer needed changes in the unit consisted of the following tasks:

- Create a core team for data acquisition, project development, and assignments.
- Properly understanding the reservoir.
- Identify and prioritize conformance problems.
- Perform the proper diagnostic tests.
- Analyze the diagnostic tests (knowledge from data).

- Choose and design the proper conformance solution based on the needs of the subject wells.
- Apply those conformance solutions to an ever- enlarging area and grow technology out into other units.
- Evaluate the funding considerations (main level vs. regional entities).
- Report and document the methods used, the structure developed to address conformance in large units, and submit reports and papers for decimation of knowledge and technology sharing.

This process has been and will be a foundation to establish the best practices for dealing with conformance issues in this project. The information gained from the original to current treated wells will be used to fine-tune the conformance analysis process for application to the rest of the CMU conformance problems. The best practice process will continue to be applied to other OPL conformance candidates and will be used to help train additional OPL professionals for work with conformance problems.

ACKNOWLEDGMENTS

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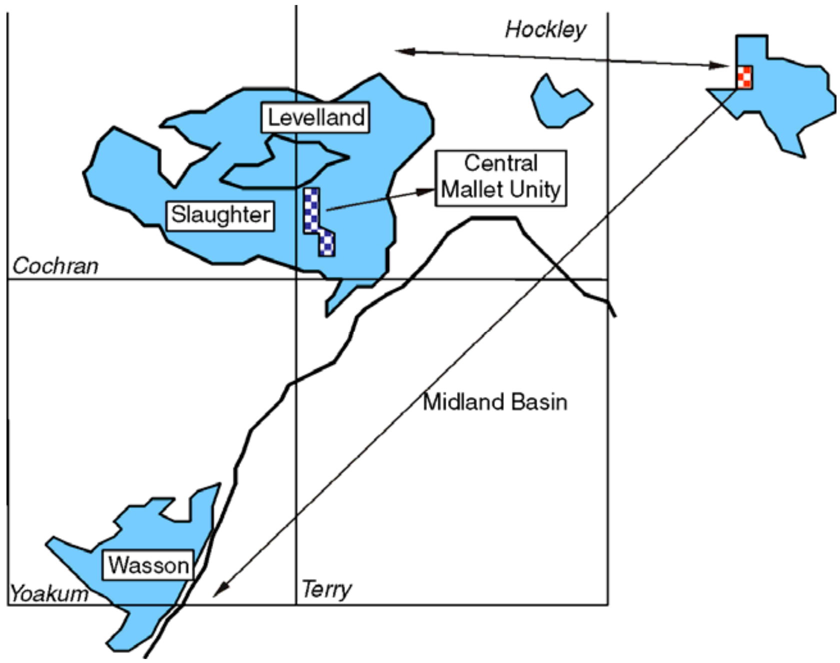

Figure 1 — Location Map

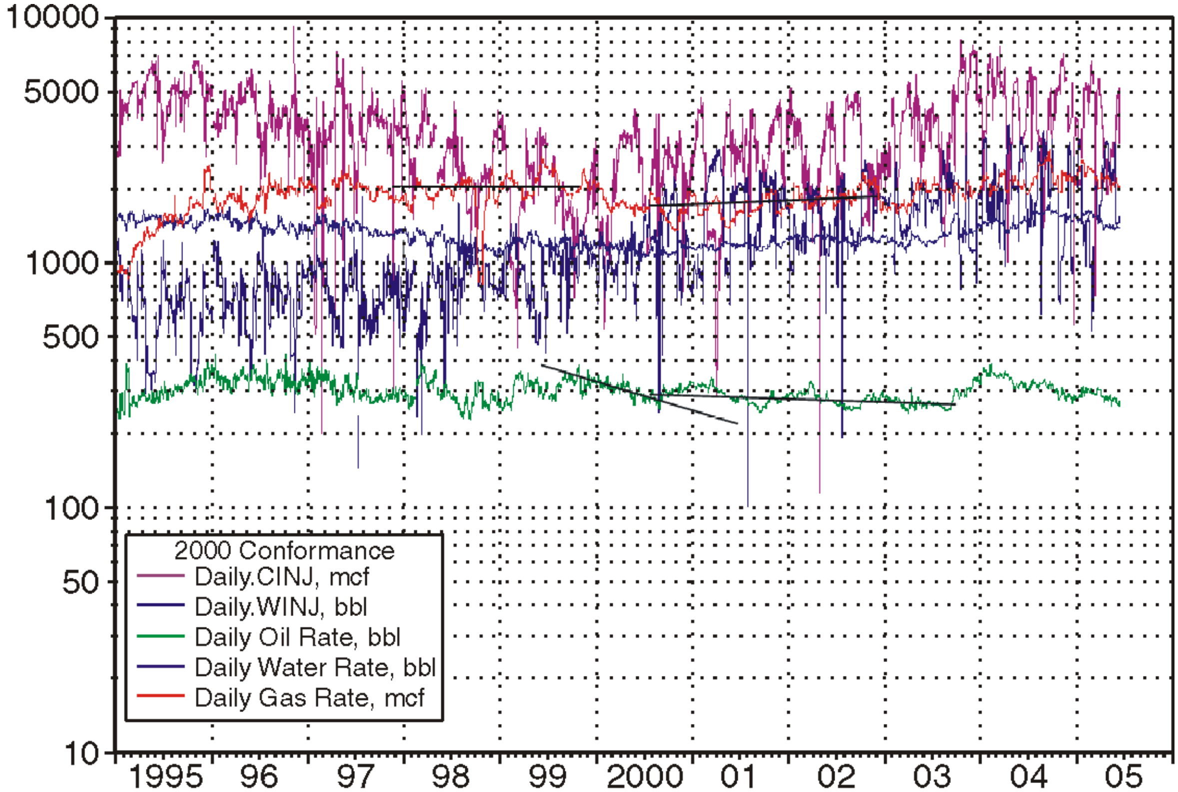

Figure 2 — Combined Production of All Six Wells

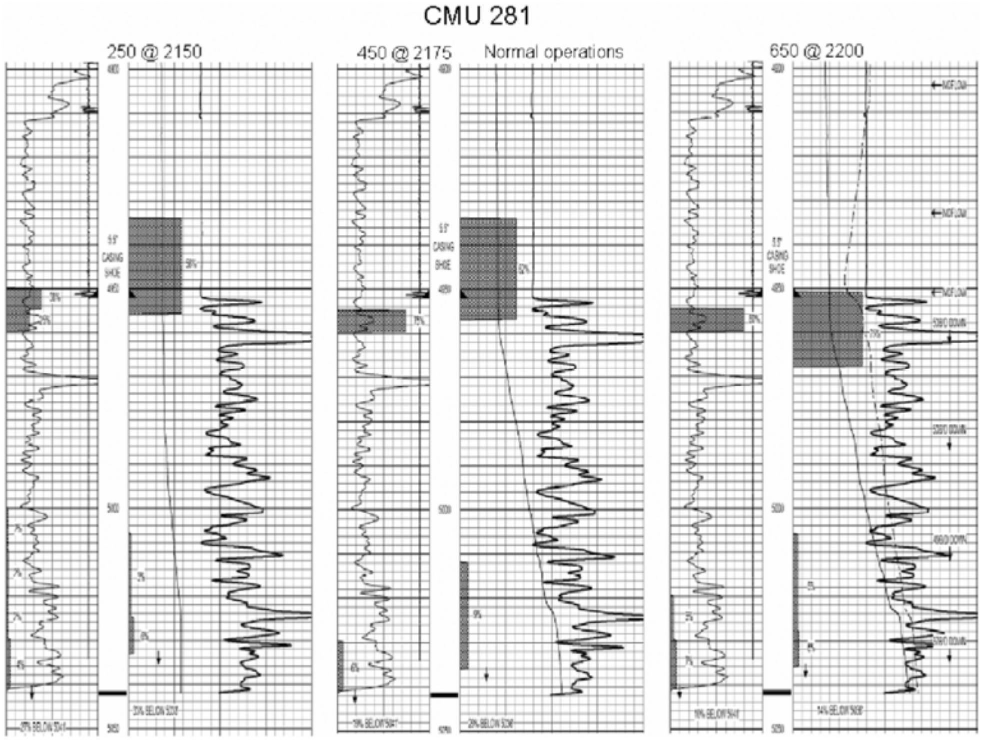

Figure 3 — Profiles at (1) normal injection rates, (2) reduced injection rates, and (3) increased injection rates.

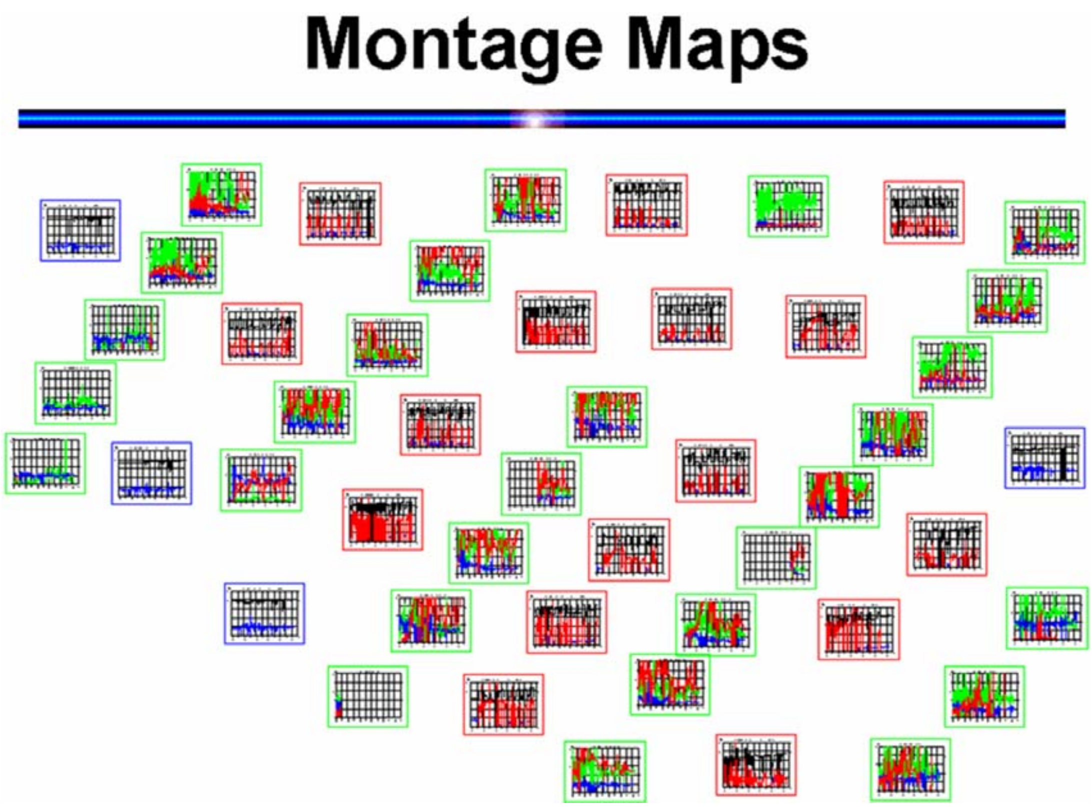

Figure 4 — All breakthrough pairs identified by the study had been previously identified by montage plots and conformance plots (see Figures 5 and 6).

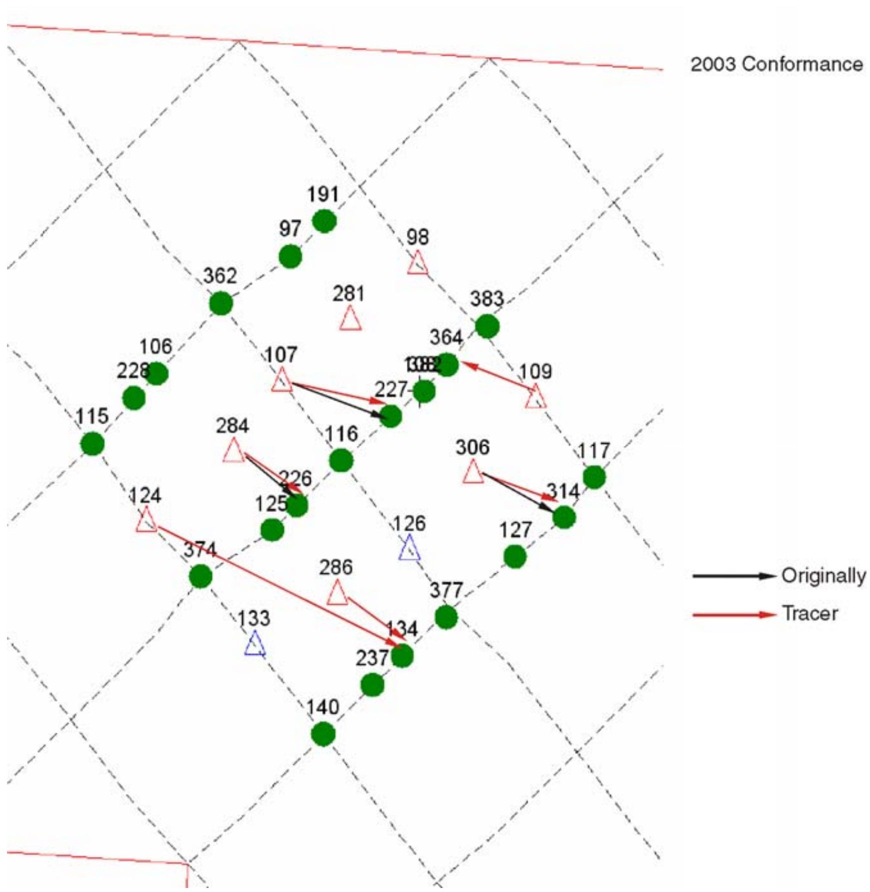

Figure 5 — Tracer Study Conformance Plot

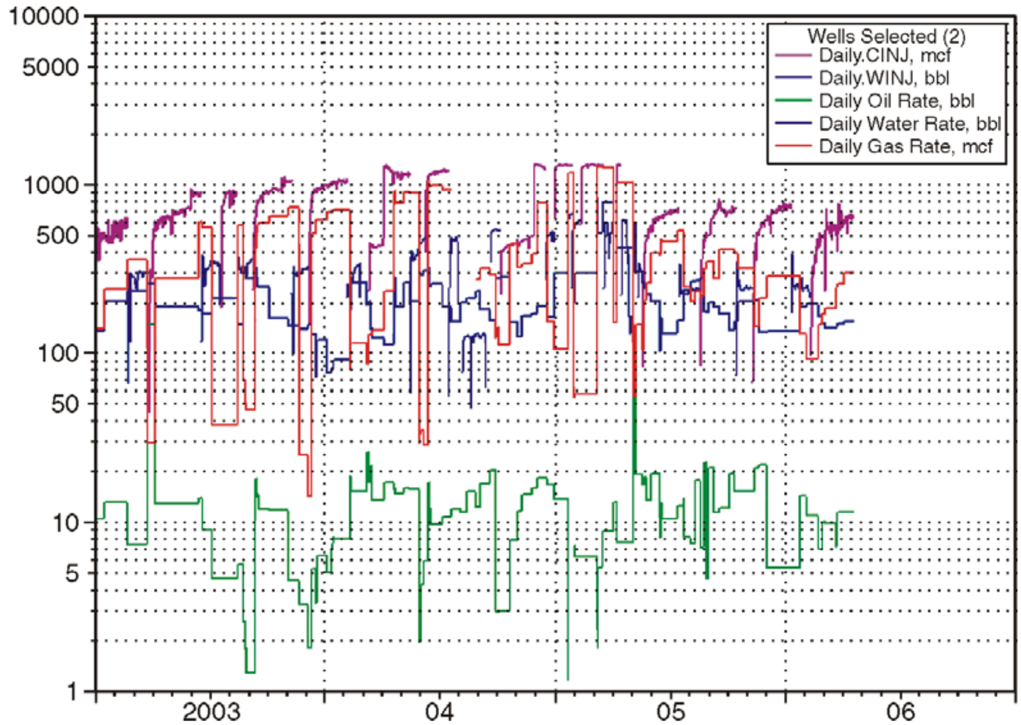

Figure 6—Tracer Study Conformance Plot

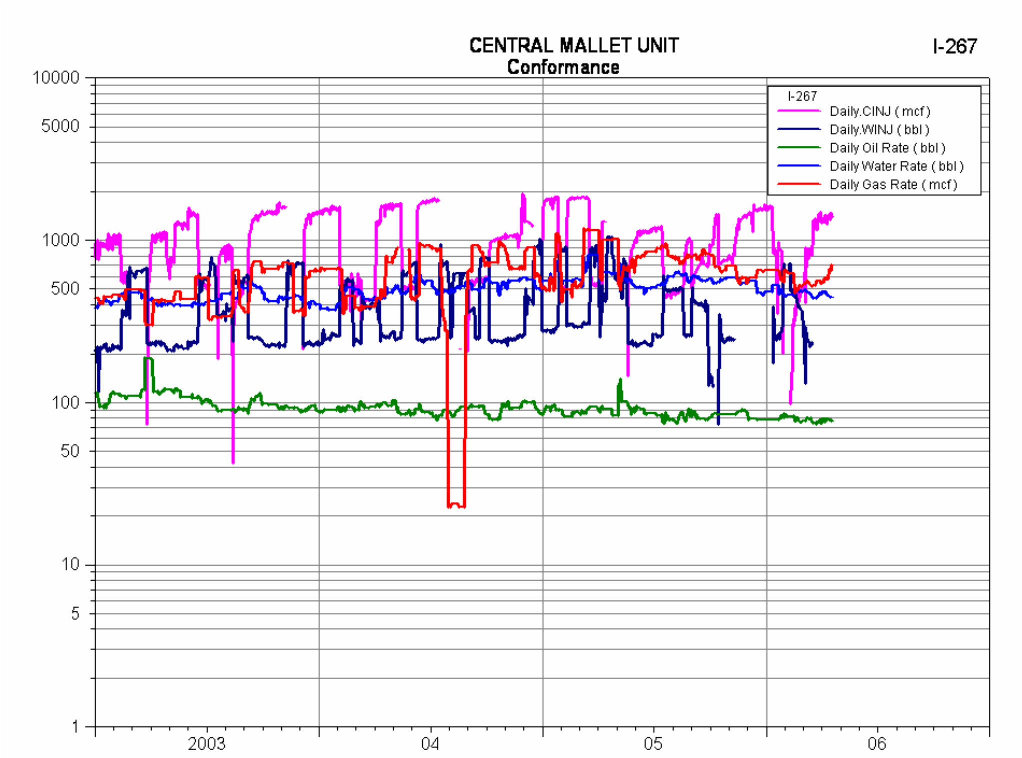

Figure 7 — Typical Pattern Plot Showing Wells Affected by the Treated Injector

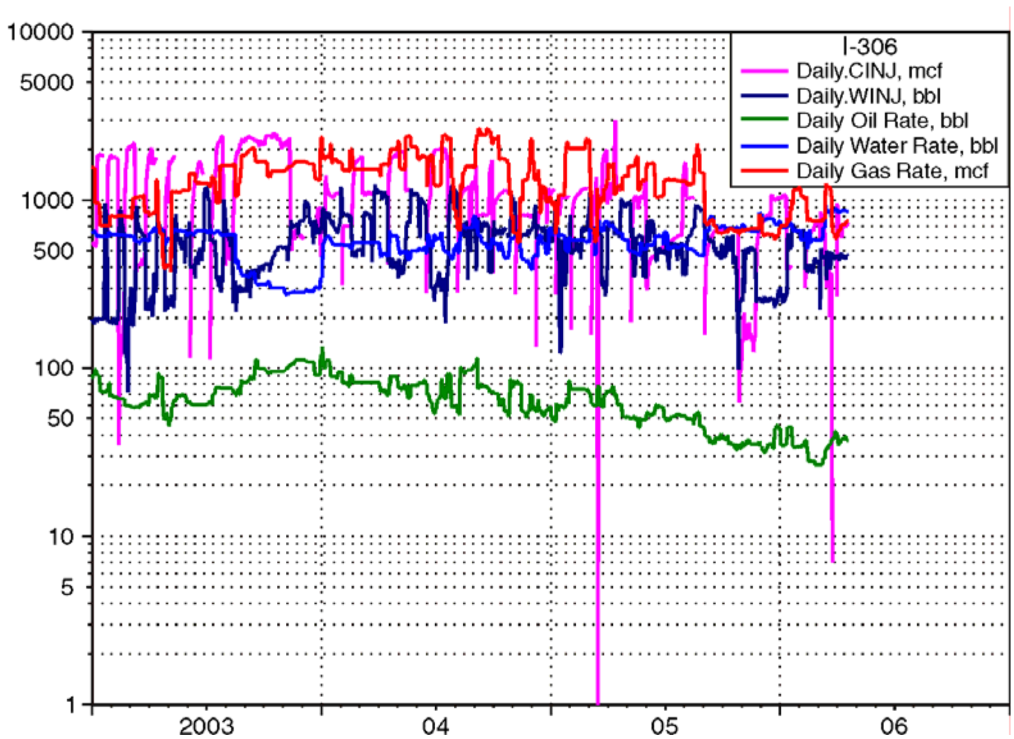

Figure 8 — Typical Pattern Plot Showing Wells Affected by the Treated Injector

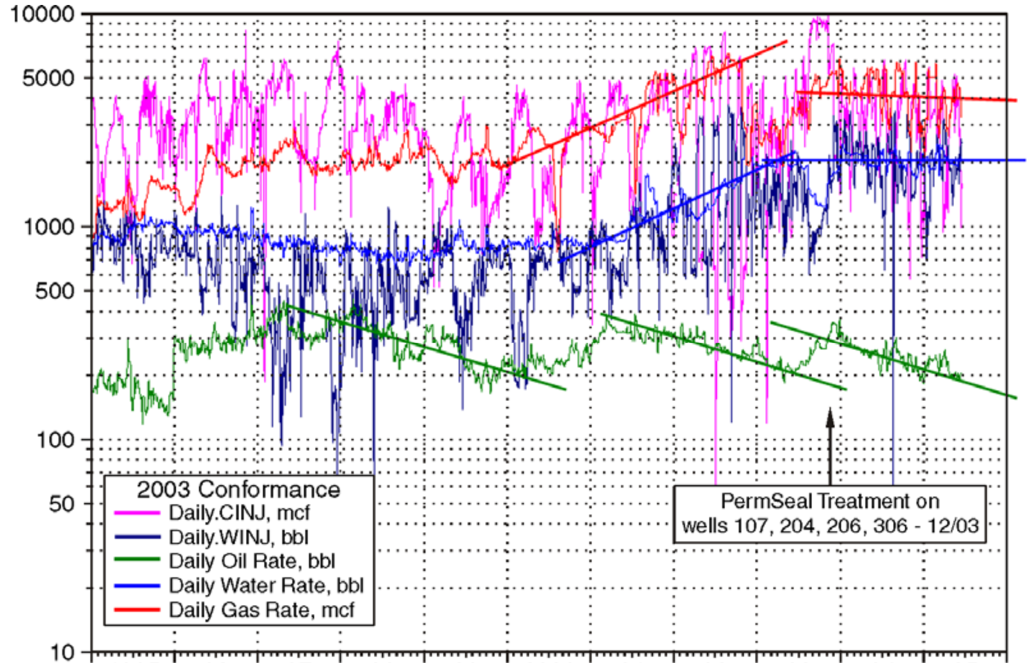

Figure 9 — Results of 2003 Central Mallet Conformance Work

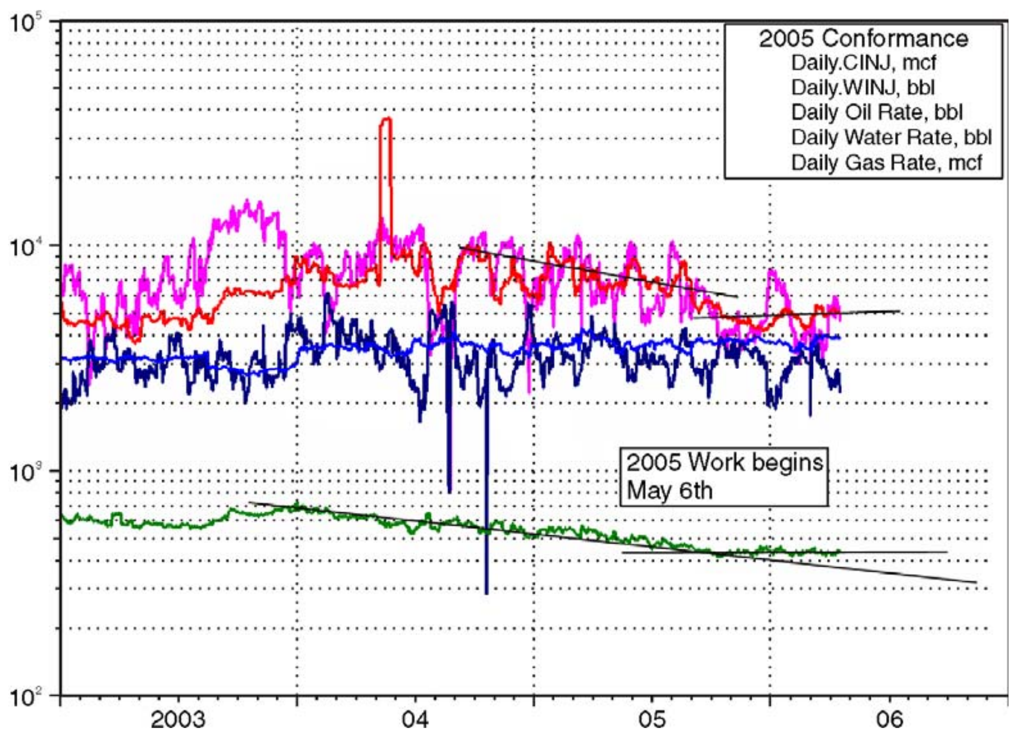

Figure 10—Results of 2005 Central Mallet Conformance Work

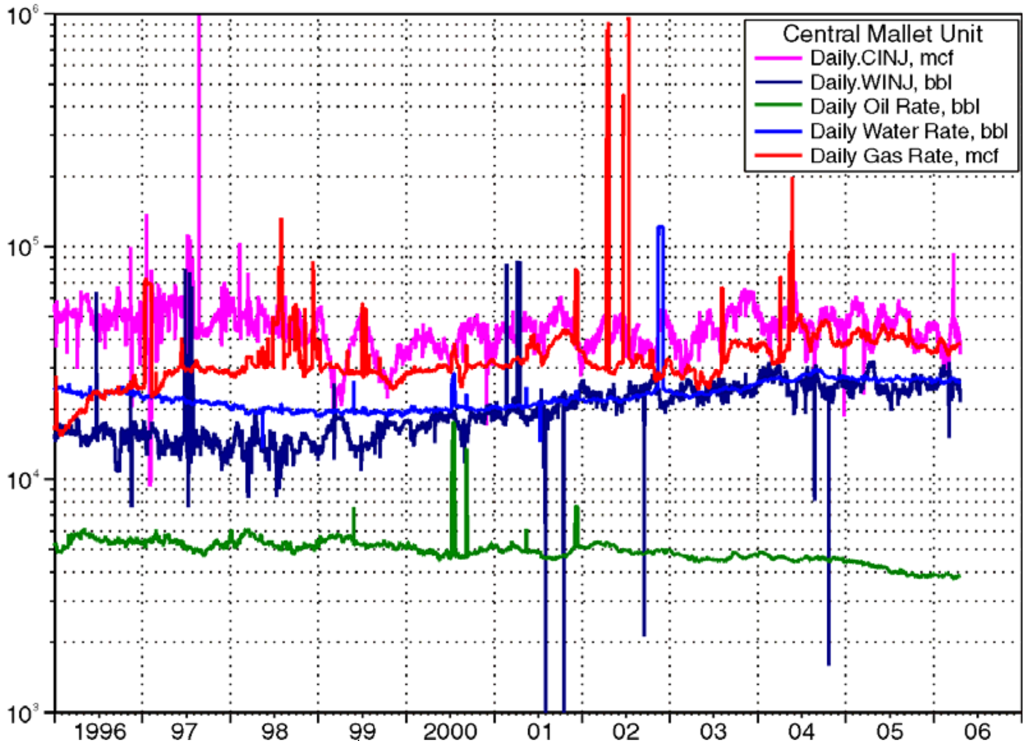

Figure 11 — Results of 1st Quarter of 2006 Central Mallett Conformance Work

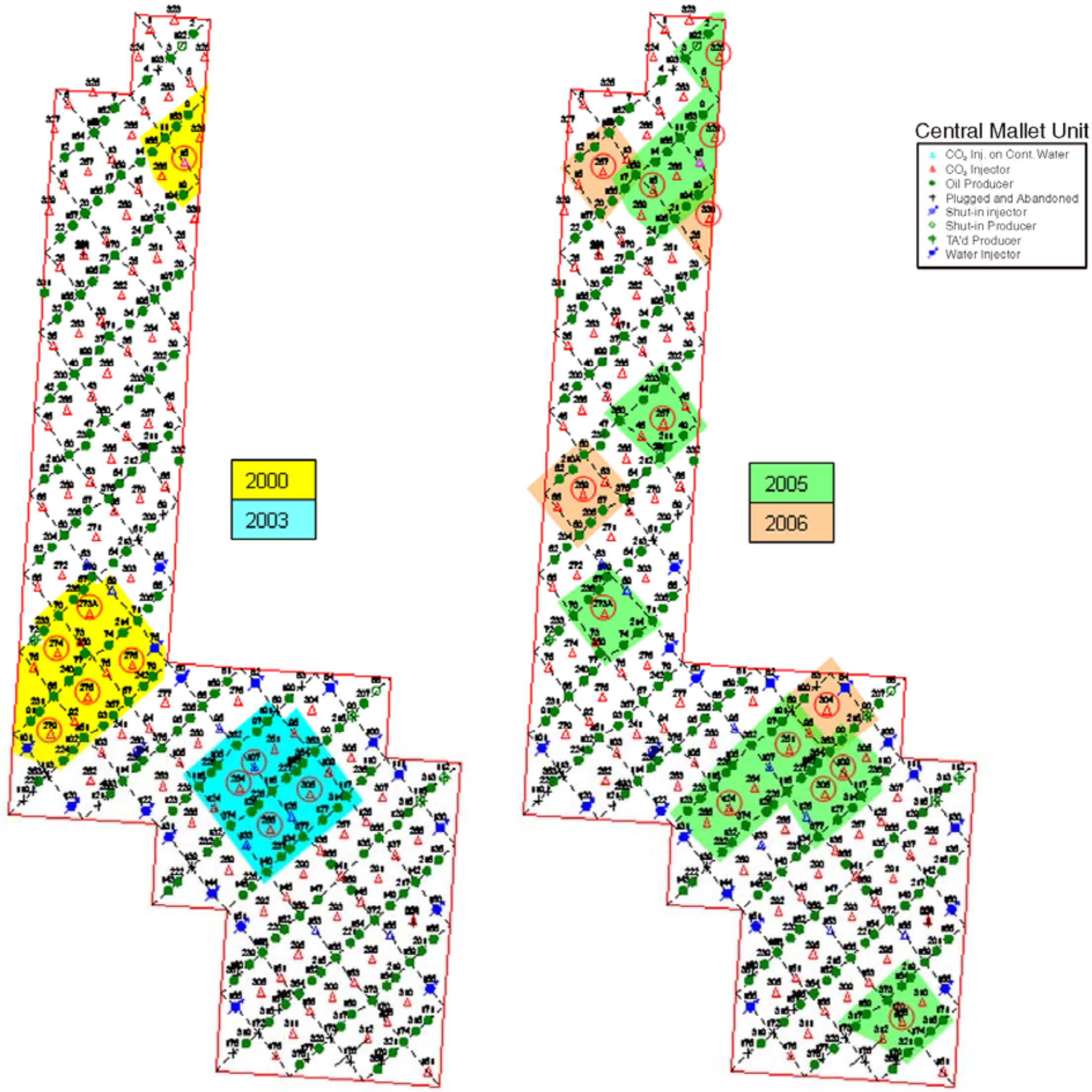

Figure 12—Highlighted patterns indicate the year work was performed in the Central Mallet Unit.

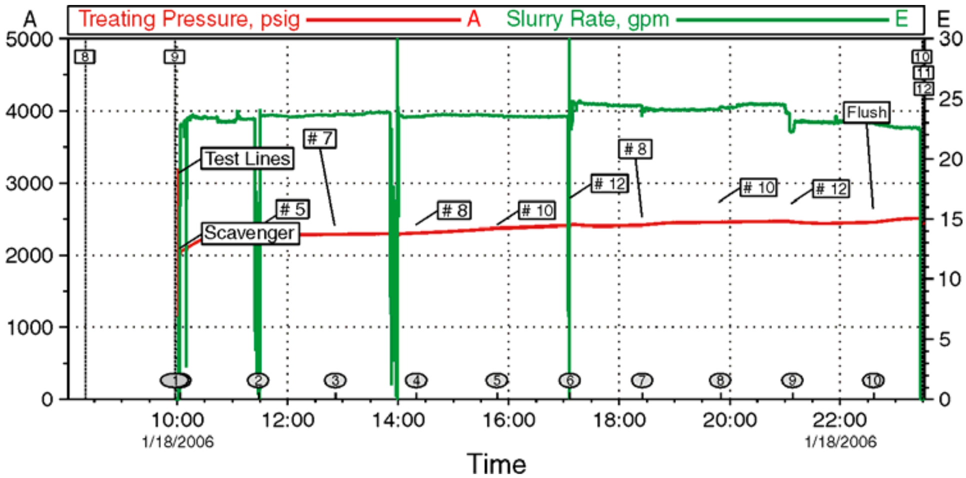

Figure 13—Example of a Typical In-Situ Generated Polymer [IGP] System Treatment

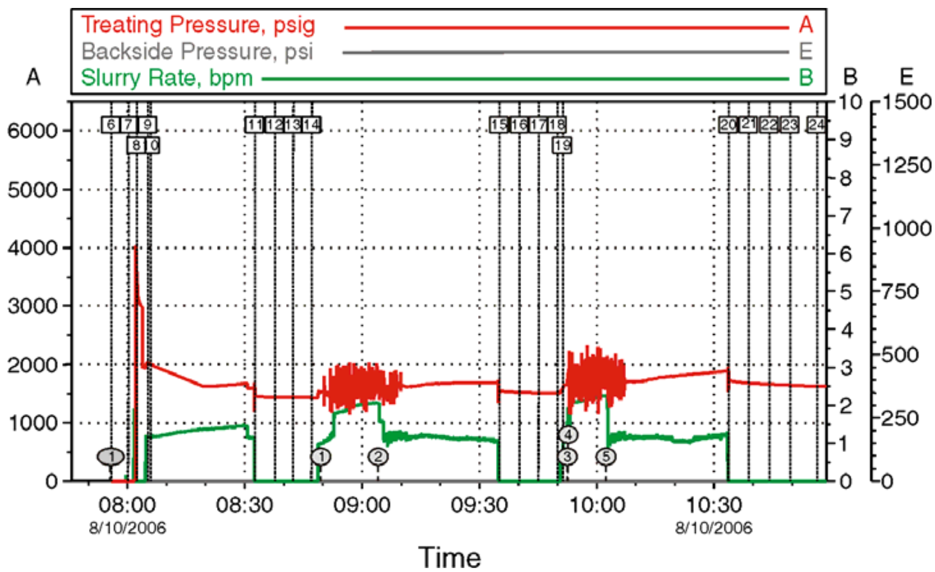

Figure 14—Example of a CP Crystallized Polymer C System Treatment

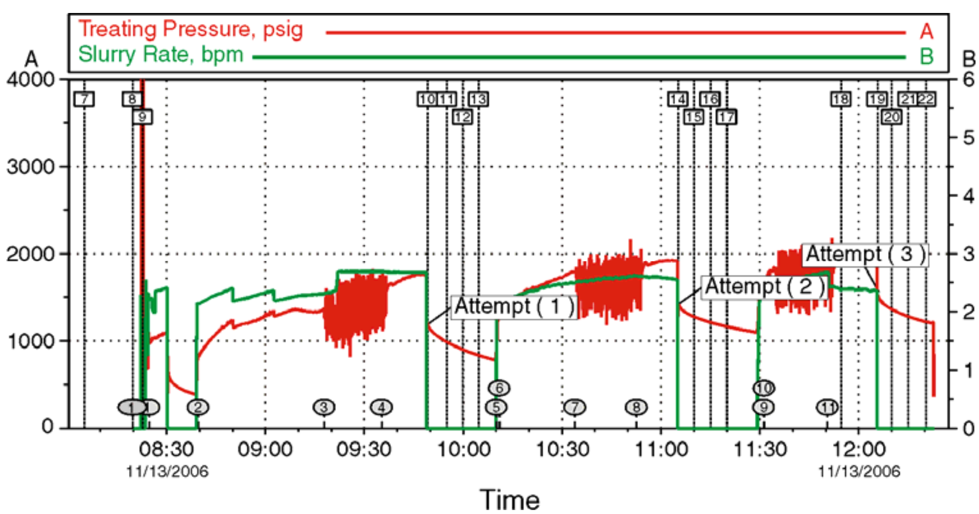

Figure 15—Example of Using Three Stages to Block Off a Fracture Communication with a CP Crystallized Polymer C System Treatment