STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO. **CASE NOS. 24123**

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO. **CASE NOS. 23614-23617**

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN LLC TO AMEND ORDER NO. R-22026/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO. **CASE NO. 23775**

APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY, LEA COUNTY, NEW MEXICO.

CASE NOS. 24018-24020 & 24025

CROSS EXHIBITS 1 - 9

Submitted March 7, 2025

 Goodnight Cross Exhibit 1

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Problem Diagnosis, Treatment Design, and Implementation Process Improves Waterflood Conformance

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ABSTRACT

The Eunice Monument South Unit (EMSU) produces from the Grayburg formation in southeast New Mexico. The unit has higher than expected water production and lower than expected oil production since a waterflood was installed in 1986; poor vertical flood conformance is to blame. A major project was initiated in 1996 to characterize the reservoir and improve the flood conformance where possible.

Reservoir characterization included mapping high permeability streaks, material balance, and percent pore volume swept calculations. Two techniques, production data diagnostics and injection well diagnostics, were then applied to characterize the performance of individual wells. The subsets of wells that were identified as underperforming by each method were compared and a focus area was selected to pilot test a waterflood conformance correction program. Primary problems discovered included water cycling through high-permeability streaks, water injection into the gas cap, and wellbore zonal isolation problems.

The waterflood conformance correction program comprises problem diagnosis, treatment selection and design, treatment execution, and treatment evaluation. Several different treatments (cement squeeze, near-wellbore gel treatment, and deep-penetrating gel treatment) were executed depending on the problem encountered. This program has been implemented on 29 wells in EMSU. Production response to the treatments is discussed.

Introduction

The Eunice Monument field is located in southeastern Lea County, New Mexico, approximately 15 miles southwest of Hobbs, New Mexico, along the northwestern edge of the Central basin platform. The original Eunice pool was discovered in 1929 and developed on 40-acre spacing. Oil production peaked in 1937 at 25,542 barrels of oil per day.

Chevron currently operates two adjacent waterflood units in the Eunice Monument field, the Eunice Monument South Unit (EMSU – 14,190 acres) and the Eunice Monument South Unit B (EMSUB - 3000 acres). The EMSUB shares a common unit boundary along the northwestern border of the EMSU (southeast corner of the EMSUB). EMSU was unitized February 1, 1985, with water injection commencing November 1986. EMSUB was unitized December 1, 1990, with water injection commencing March 1991. Both units are developed on 40-acre well spacing with 80-acre 5-spot patterns. EMSU and EMSUB produce oil primarily from dolomites of the Grayburg formation. A minor amount of oil is produced from the overlying lower Queen (Penrose). The underlying San Andres formation, a water drive reservoir, is used for supply water. Hydrocarbon entrapment in the field is controlled by a combination of structural-stratigraphic trapping located along the northwest margin of the Central Basin Platform.

As of April 1, 1998, EMSU consisted of 164 active producers, 138 active injectors, 4 water supply wells, and 1 water disposal well. EMSUB consisted of 49 active producers and 51 active injectors. The injection facilities are shared by both units.

Lithology. The Grayburg is a carbonate ramp environment, relatively thick and porous to the southwest (more packstones/grainstones) and thin and tight to the northeast (more wackestones/mudstones). Sets of parasequences stack to form six recognizable zones based on correlations of relatively thin (approx. 2- to 10- ft thick), generally impermeable sandstones (siliciclastics). The zonal markers that can be correlated across most of the unit are made up of dolomitic sandstones (subarkose to calclithites), which are composed of well-sorted and very fine-grained siliciclastic sand. These siliciclastic "markers" are very well developed to the northeast in the back-shoal environment, which makes zonal correlations fairly obvious and straightforward. To the southwest, however, in the high-energy shoal environment, these siliciclastic markers are much less developed and confidence in the zonal correlations deteriorates. These siliciclastics tend to be very porous but are impermeable and therefore act as vertical barriers to fluid movement. The general lack of siliciclastics to the southwest in the high-energy shoal environment--where thick, porous, grain-rich parasequences tend to stack--has produced a more homogeneous reservoir that has more of a bottom- and edge-water drive component. To the northeast, in the back-shoal environment, the siliciclastics tend to vertically compartmentalize thinner, less porous, and more muddy parasequences that promote more of a solution gas-drive component.

Zones 1, 2, and 3 are very clean dolomites (floodable reserves, solution gas drive). Top of Zone 1 is the top of the Grayburg. Generally, Zone 1 has been processed by waterflooding. It is tight in the northeastern half of the field and because of this, it is more brittle and tends to be more fractured than the rest of the Grayburg section. The lower half of Zones 1 and 2 have the most high permeability streaks (solution enhanced grainstones typically 18-in to 4-ft thick) and tend to have edge water drive connected to the Grayburg shoal along the southwest of the field.

Zone 4 is clastic rich (silty/sandy) and forms a pressure barrier. It is vertically impermeable and can have good porosity zones. This zone has a karsted surface in its upper portion.

Zone 5 is typically water drive (3 to 20% oil cut) and Zone 6 overlies the top of the San Andres and contains an unconformity in its upper part. There are oil shows well down into the San Andres.

Waterflood performance. The total oil production rate at EMSU decreased after the waterflood was implemented in 1986 primarily due to conversions to injection (**Fig. 1**). However, patterns did suffer from rapid water breakthroughs, slow pressure increases, and low injection:withdrawal ratios. In all, the oil production rate decreased in 70% of the wells in the field after the waterflood was implemented (**Fig. 2**). It is believed that poor reservoir flood conformance reduced the waterflood effectiveness. The EMSU Waterflood Conformance Project was initiated in 1996 to characterize the flood conformance and correct it if feasible. The project focus area (referred to as the conformance diamond) consists of 16 contiguous 80-acre producer center patterns. Several elements of this project are described in this paper.

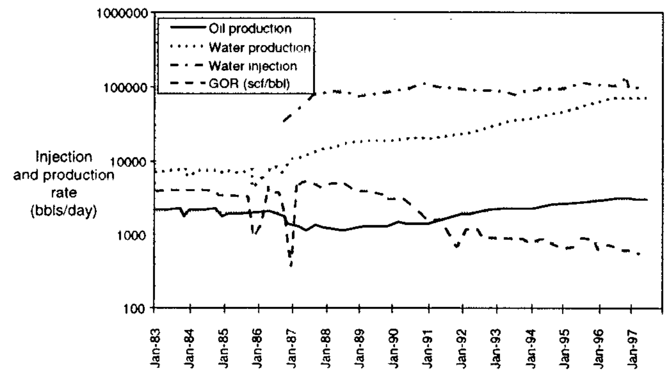

Fig. 1.– Illustration of EMSU production history. Water injection began in 1986.

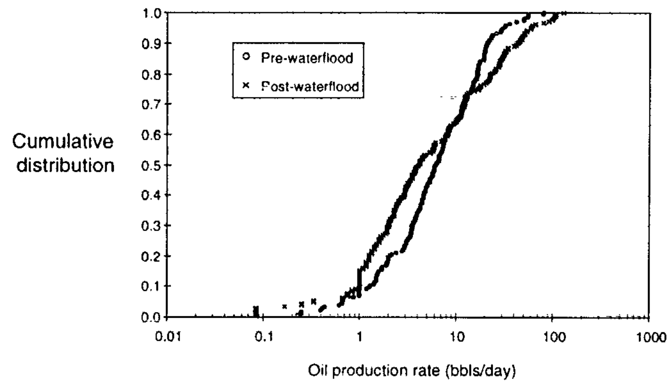

Fig. 2.– Comparison of prewaterflood and postwaterflood oil production rate.

Reservoir Characterization

The EMSU reservoir characterization was a long process that included the creation of conformance cross-sections, mapping of high perm streaks, calculating the percent hydrocarbon pore volume swept for each major zone, and production diagnostics.

Conformance cross-sections. Conformance cross-sections were built for each producer-centered pattern in the field. Injection profiles, porosity, gamma ray traces, and wellbore configuration history were correlated by structure for each well. These cross-sections were useful for verifying strong injector-producer correlations, identifying thief zones, and provided data for the zonal processing calculations. Permeability from core data was used, when available, to confirm the location of high-permeability streaks. **Figure 3** illustrates one of the structural cross-sections built for EMSU. The cross-section line from well 257 to 259 is show in **Fig. 8**.

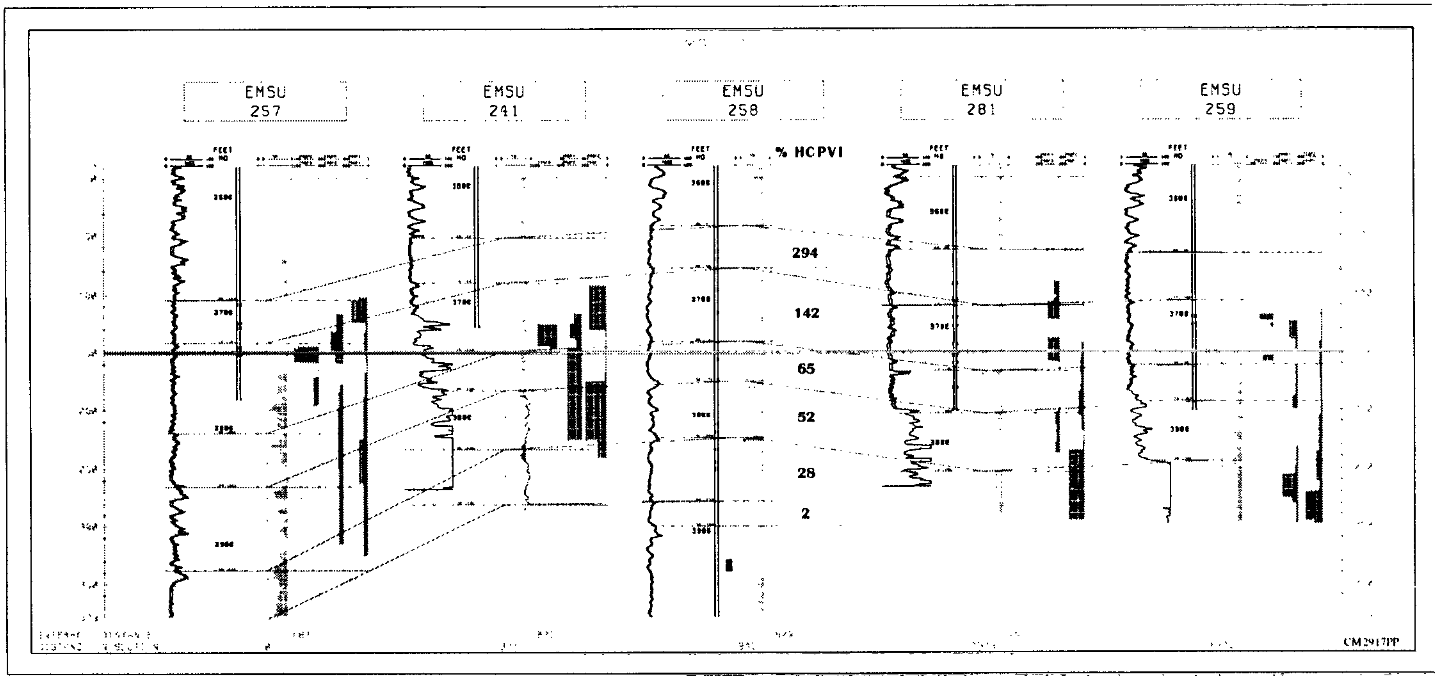

Fig. 3.– Structural cross-section.

The visual representation of the wells in each pattern facilitated the study of fluid movement in the pattern. It also highlighted the fact that a substantial fraction of the injected water was entering the gas cap (formation above the -150-ft marker). Zone 1 and the majority of Zone 2 are in the gas cap throughout the conformance diamond.

Mapping of high perm streaks. Maps of high permeability streaks were created for each zone and/or perm-streak trend in order to capture their aerial extent. Core permeability data, core descriptions, and log data were used in constructing these maps. Where permeability data was absent or limited, geostatistical models were incorporated.

Zonal processing. A waterflood monitoring tool, developed by Chevron Petroleum Technology Center, was used to calculate the zonal processing of each zone. Moveable hydrocarbon pore volume calculations were generated for each pattern accounting for S_{wi}, S_{or}, and S_{gr} as immobile. Monthly injection volumes were then allocated to each zone using injection profiles and the cumulative injected volume was calculated for each zone. A straight line interpolation was used to account for changes in injection profiles between the dates each profile was run. Sweep efficiencies were not accounted for. The monitoring tool showed that Zones 1 and 2 were overprocessed, and Zones 3, 4, and 5 were underprocessed. An overprocessed zone had more than 100% of the hydrocarbon pore volume swept by water. Visual inspection of the conformance cross section gave a quick indication of vertical sweep efficiency and lent more credence to the seriousness of the over processing.

Production diagnostics. Production diagnostics for water or CO_2 floods utilize six plots. They are as follows:

1) production history
2) production diagnostic plots (WOR and WOR' versus time)[1]
3) production decline curves (oil and water versus cumulative barrels of oil)
4) injection and production pattern plots (BWIPD from offset injectors, BWPD, and BOPD all versus time)
5) injection withdrawal ratio ($Q_{injection}/Q_{production}$).
6) production and injection data contour and bubble maps.

These plots and maps are used as an initial screen for production well performance. The information gathered may indicate the well's general production mechanism. Typically, a few specific pieces of additional information must be collected to confirm suspected production mechanisms and problem types.

The data required for production diagnostics are monthly average BOPD, BWPD, and BWIPD and/or Mscf/D for each pattern. It is helpful to have a brief description and history of the field and the individual wells. The well history should contain the dates and description of workovers. The field history should include the general characteristics of the reservoir structure and dates when major field events occurred; i.e., pattern realignment, unitization, infill drilling, waterflood installation.

The production diagnostics were used to assess the severity of water cycling between injector and producer pairs. Characteristics of a water control candidate include a strong correlation between injected and produced fluid rates, a sharp increase in the WOR versus time plot, and a sharp decrease in the rate of oil production. The oil rate decreases sharply at the onset of water injection because the injected water races through a highly transmissible pathway and overwhelms the lift capacity of the production well. The resulting high wellbore fluid level suppress the oil production from low-pressure, low-permeability zones, sometimes resulting in downhole crossflows..

The signature of a direct communication between an injector and producer is shown in **Figs. 4-6**. Three plots in particular were used to ascertain the degree of communication between the injectors and the producers. The plots used were the injection and production pattern plots, **Fig. 4**, the injection withdrawal ratios, and the production diagnostic plots, **Fig. 5**.[1]

Figures 4-6 illustrate examples of each plot for a high degree of injector to producer communication. **Figure 4** indicates that water increased and oil decreased in the producer soon after injection began. **Figure 5** shows a step change in the WOR at the onset of water injection. This WOR change occurs at the same time as the oil rate decreased to around 1 bbl/day (**Fig. 6**). These are symptoms of a serious conformance problem that may be correctable depending on the nature of the problem.

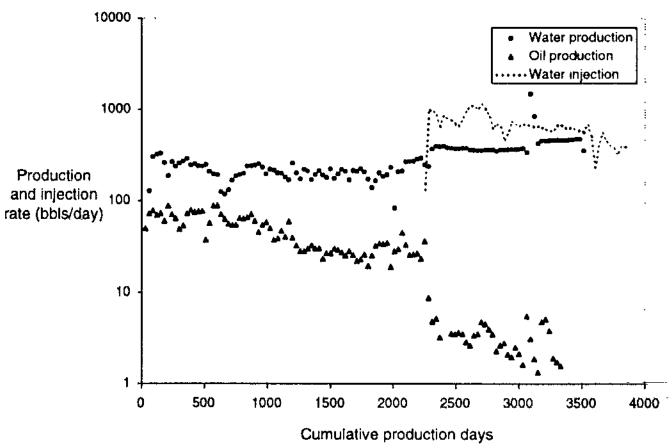

Fig. 4.– Illustration of oil rate decrease and water rate increase that coincide with injection in an offset injector.

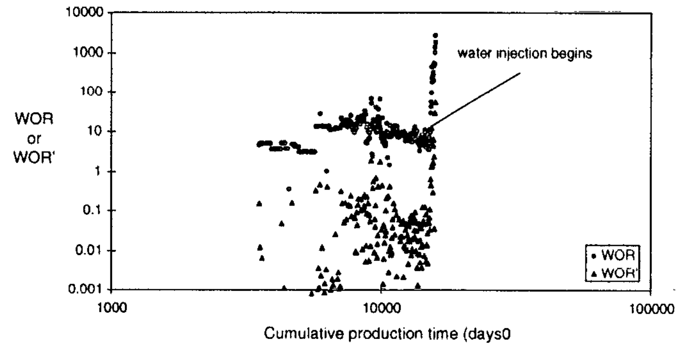

Fig. 5.– Diagnostic plot for a production well in direct communication with an injection well.

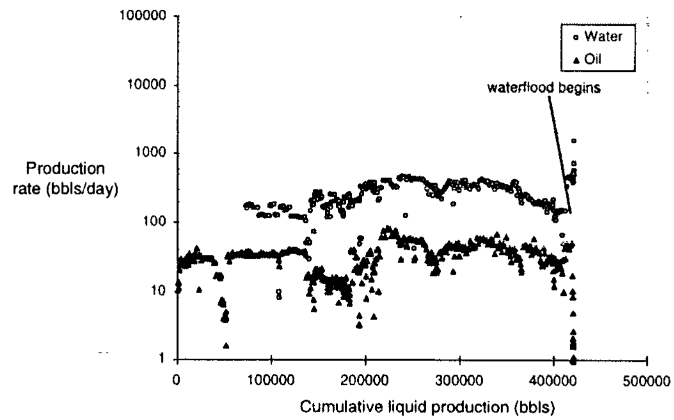

Fig. 6.– Oil rate decline for a production well in direct communication with an injection well.

Focus Area

Conformance problems were observed over the entire field (**Fig. 7**). A focus area, referred to as the conformance diamond, was defined as a pilot area for the conformance improvement work (**Fig. 8**). It was verified during the reservoir characterization that the conformance diamond contained natural fractures, injection into a gas cap, and areally extensive permeability streaks; all of which cause the characteristics illustrated in **Figs. 4-6**. Furthermore, these problems were isolated to Zones 1 and 2 in the conformance diamond. The overall goal for the conformance diamond was to increase oil production and decrease water cycling. The steps taken to achieve the goals include elimination of water injection into the gas cap and stimulation of underprocessed zones in both injection and production wells. Injection into the gas cap was initially allowed at the onset of waterflood to eliminate the possibility of sweeping oil into the gas cap and decrease fill up time.

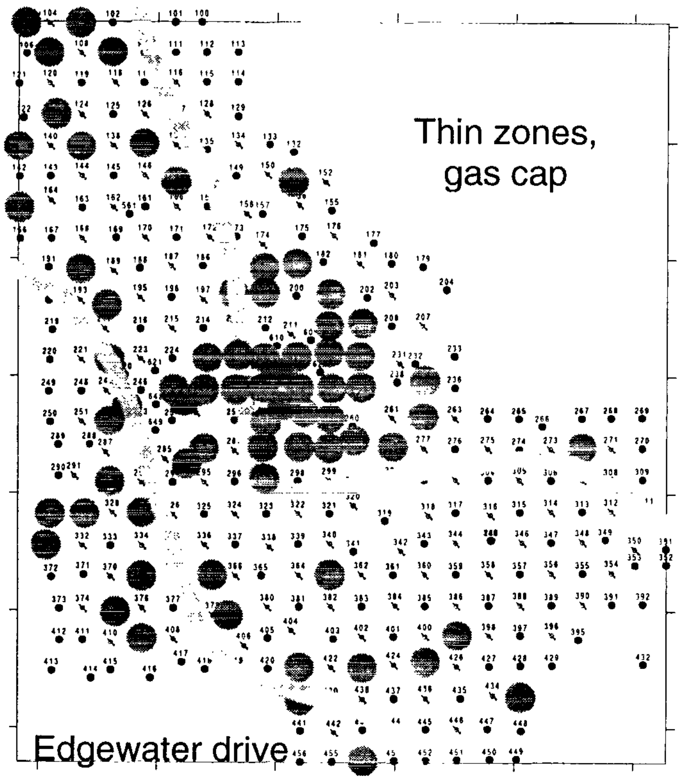

Fig. 7.– Wells that have symptoms of poor reservoir conformance are marked by a large circle.

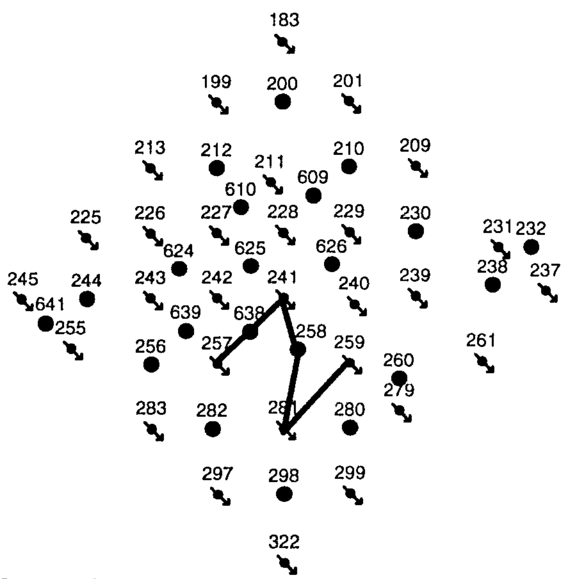

Fig. 8.– Conformance diamond. The "Z" indicates the conformance cross section shown in **Fig. 3.**

Treatment design. Three different treatment designs were applied in the conformance diamond depending on the problem type, the well condition, and the reservoir features. These three treatment types were cement squeezes for abandoning the gas cap and high-permeability streaks, a polymer gelant for deep penetration into matrix, and a flowing gel for treating natural fractures. A treatment matrix was developed for selecting different cement slurries and gel types depending on injectivity tests, zonal isolation, and wellbore conditions (see **Table 1** at the end of the text). Cement squeeze treatments were used when an areally extensive vertical barrier isolated an overprocessed zone from adjacent target zones. A near wellbore abandonment was sufficient in such a case. The gelant was applied when there was communication in the reservoir between the layer being treated and adjacent zones *and* matrix flow was evident. The flowing gel was applied when linear flow behavior was evident.

The procedure detailed below is one of the polymer treatment designs. The procedure begins by stimulating the zones targeted for production (including acid wash of zones targeted for polymer treatment), followed by a polymer gel treatment for in-depth zone abandonment, and finally, a cement squeeze treatment for near-wellbore isolation of the zones containing polymer.

Two different polyacrylamide chrome acetate crosslinked systems were available at the wellsite (see **Table 1**). System 1 had a 24-hr working time (can penetrate matrix for 24 hours), used an intermediate molecular weight polymer with a low degree of hydrolysis, and was for wells that exhibit radial flow characteristics, (**Fig. 9**). System 2 was a preformed gel that used a high molecular weight polymer with a high degree of hydrolysis. System 2 was for wells that exhibit linear flow characteristics. Both systems used 0.5% polymer by weight.

1. Collect required execution data:
   a) Tubing packer depth/displacement volume.
   b) BHST
   c) BHSIP
   d) Maximum BHP/STP.
2. Acidize wash the target interval with approximately 20 gal/ft HCl to insure good injectivity.
3. Set a retainer below the zone targeted for shutoff and acid stimulate the zones below the retainer (use foam for acid diversion).
4. Determine the conformance treatment placement technique (use the placement technique selection guide in SPE 38325).[2]
5. Employ appropriate placement technique (the remaining steps are for mechanical isolation of an upper zone, protecting the lower zones).
6. Plugback with a packer and sand topped with a $CaCO_2$ pill.
7. Move in and rig up the mixing and pumping equipment.
8. Hydrate the polymer in the mixing equipment.
9. Pressure test lines.
10. Begin injectivity test.
    a) Inject System 1 at one bbl/min.
    b) Monitor injectivity decline.
    c) If injectivity decline is that of radial flow (**Fig. 9**), continue treatment with System 1 until design volume criteria are met.

d) If injectivity decline is that of linear flow (**Fig. 9**), switch to System 2 and pump until design volume criteria are met.

11. Continue monitoring injectivity decline for duration of treatment.
12. Go to flush when either of the design volume criteria in a) or b) is met, or when both conditions in c) and d) are met.
    a) total design volume has been pumped
    b) injection rate falls below 0.2 bbls/min at the maximum injection pressure (just below fracturing pressure).
    c) Condition 1: Monitor and plot injectivity (*IJ*) vs. cumulative volume injected. Condition 1 is met when IJ falls to 0.5 BPD/PSI, where: IJ = BPD / (BHTP - P_{res})
    d) Condition 2: Monitor and plot resistance factor (*RF*) versus cumulative volume injected. Condition 2 is met when RF > 7.0, where: $RF = IJ_{init} / IJ_{trtg}$ and $IJ_{init} = BPD_{init} / (BHTP_{init} - P_{res})$, and $IJ_{trtg} = BPD_{trtg} / (BHTP_{trtg} - P_{res})$
13. Flush to tubing packer with System 1 or 2 without the crosslinker when job is done (low pH crosslinker retards cement).
14. Rig down gel mixing and pumping equipment.
15. Shut in until ready for cement squeeze (cement cap was applied to provide near-wellbore strength). Minimize the shut in time between the end of the polymer treatment and the start of the cement squeeze.
16. Take precautions to avoid breaking down the formation during the cement squeeze.
17. The wells with polymer System 1 will be shut in for 72-hrs after the polymer treatment. System 2 only requires a 24-hr shut-in.
18. Drill out cement and plugs.
19. Inspect pumps, tubulars, and wellhead equipment. Reinstall production or injection strings.
20. Return to production or injection slowly. Start at 100 bbls/day and increase over a 72-hr period.

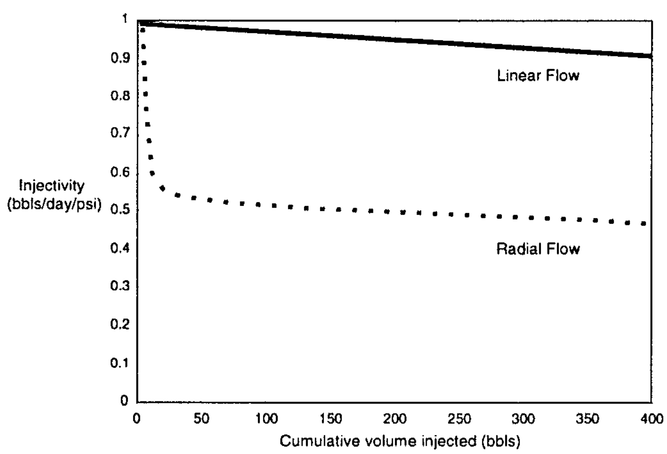

Fig. 9.– Location injectivity test verifies flow geometry.

Results

Thirty one workovers have been executed in the conformance diamond to date. The wells treated include 22 injection wells and 7 production wells. A summary of the treatments is given in **Table 2** (at the end of the text). The injection well treatment results are shown in **Table 3** and the production well treatment results are shown in **Table 4**.

Production response. The work in the conformance diamond began in March 1997 and extended through April 1998. **Figure 10** shows the combined water production, oil production, and water injection in the conformance diamond. The change in the WOR slope in 1994 indicates the onset of serious water cycling. Production changes due to injection well treatments take many months to occur because the underprocessed zones in associated patterns must fill up and pressurize before maximum waterflood response is observed. However, preliminary results show an increase in oil production with decreasing water injection, water production, and WOR.

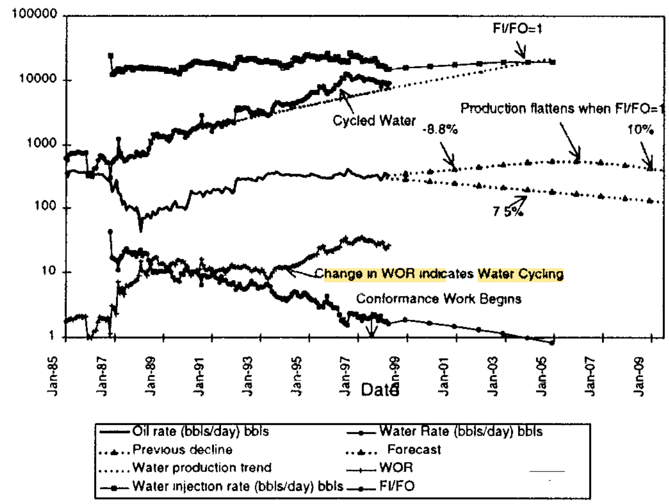

Fig. 10.– Production in the conformance diamond.

The following wells showed a rapid production response following treatment:

1. EMSU 638 production doubled following a workover that shut off the gas cap and stimulated low-pressure zones. Additionally, each of the surrounding injectors had shutoff treatments to eliminate injection into the gas cap.
2. Emsu 238 had a 30% production increase following a Zone 6 plugback, stimulation of the productive zones, and injector conformance work in the surrounding injection wells.
3. EMSU 610 had a 50% production increase as a result of gas cap shutoff treatments in offset injectors.
4. EMSU 609 production increased 30% immediately following a shutoff treatment on offset injection well 211.

5. EMSU 212 had a 60% production increase a few months after gas cap shut-off treatments in an offset injector.
6. EMSU 282 production dropped sharply following an injector conformance treatment on EMSU 257 (may not be related), and then rebounded following a clean out and stimulation treatment on EMSU 282 in January.

Economic Analysis. Decline curve analysis shows an incremental recovery from preliminary results. The base oil rate decline prior to the conformance project was 7.5% during 1996. The current incline in oil production is -8.8% which matches the same incline prior to water cycling in 1990 and 1991. The projected forecast for response extrapolates out the current incline until a FI/FO ratio of 1 is reached in 2004. Production then flattens out for 2 years and assumes a 10% decline which is 2.5 times the prewaterflood decline. Subtracting off the 7.5% base decline yields an incremental 1.9 million barrels of oil. The associated economics for this conservative forecast are shown in **Table 5**. The maximum upside potential is believed to be bound by the initial waterflood incline of -34% (1988-1991).

Implementation challenges. There were some problems during the execution of the conformance diamond well workovers. One common problem was behind pipe communication due to poor cement bonding (presumably due to previous acid treatments and aging wellbores), which made achieving the designed acid and cement placement difficult. Polymer treatments were not used in wells that had behind pipe communication because the desired zonal isolation could not be achieved. Isolation was also difficult in open-hole wellbores due to rugose hole conditions and wash-outs around the casing shoe. Due to behind pipe communication and open-hole conditions, sand was used along with a cast iron bridge plug or an inflate to plugback wells in order to protect the target zones from cement or gel. Crossflows caused significant problems when trying to plugback with sand. Low bottom hole pressures and thief zones also caused problems when plugging back, and made it difficult to circulate, clean-out, and gather good diagnostic data during injectivity tests. Another problem was that despite the best diagnostic efforts, some wells contained larger than expected thief zones that hindered the effectiveness of the shutoff treatment. EMSU 259 and EMSU 239 are examples of this problem and mulitple cement squeezes were required to shut off the offending zones. Other problems included squeeze jobs that leaked and the failure of some casing and tubing strings that were weakened by corrosion. It was difficult to get a good cement bond when iron sulfide scale was present. One best practice developed was to acid wash the perforations and open-hole before the squeeze in order to get a better bond. Another best practice was to perform the cement squeeze after the target zones were acid stimulated. This practice increased the success rate of cement squeezes.

Summary

A focused reservoir conformance improvement project was conducted for a section of the Eunice Monument South Unit. The project goals were to increase oil production and reduce water cycling in 16 contiguous patterns called the conformance diamond.

The first phase of the project entailed reservoir characterization. The characterization identified several items that cause waterflood conformance problems. The problem items included the existence of areally extensive high permeability streaks, water injection into the gas cap (and high permeability streaks in the gas cap), and the presence of natural fractures.

Wellbore treatments were designed to eliminate water injection into the gas cap and stimulate water injection and oil production from the underprocessed zones. Cement squeezes were applied when there was a barrier isolating the thief zone from the rest of the pay. Gel treatments were applied to achieve deep penetration into matrix or fractures.

The water injection rate into the gas cap was reduced by 85% and the oil production rate has increased by 16% as of March 1998. It is too soon after the completion of the project to give a full evaluation of the program's economic impact.

Notation

BHST	bottomhole static temperature [F]
BHSIP	bottomhole shut-in pressure [psi]
$BHTP_{init}$	initial bottomhole treating pressure [psi]
$BHTP_{trtg}$	bottom hole treating pressure during treatment [psi]
BPD_{init}	initial injection rate [bbl/day]
BPD_{trtg}	injection rate during treatment [bbl/day]
DPI	discounted profitability index [$/$]
FI/FO	fluid in / fluid out of the reservoir [bbls/bbls]
IJ	injectivity [bbl/D/psi]
IJ_{init}	initial injectivity [bbl/D/psi]
IJ_{trtg}	injectivity during treatment [bbl/D/psi]
NPV	net present value [$millions]
P_{res}	reservoir pressure [psi]
RF	resistance factor
S_{wi}	irreducible water saturation
S_{or}	residual oil saturation
S_{gr}	residual gas saturation
WOR	water / oil ratio [bbls/bbls]

Acknowledgments

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1. Chan, K.S.: "Water Control Diagnostic Plots," *SPE 30775, presented at the SPE Annual Technical Conference and Exhibition in Dallas* (October, 22-25 1995) 755-763.

2. Miller, M. J., and Chan, K. S.: "Water Control Gel Placement," *SPE 38325, presented at the 1997 SPE Western Regional Meeting*, June 25-27, 1997.

SI Metric Conversion Factors

cp x 1.0*E-03	= Pa.s
ft x 3.048*E-01	= m
°F x (°F-32)/1.8	= °C
in. x 2.54*E+00	= cm
lbm x 4.535924*E-01	= kg
md x 9.869233*E-04	= μm^2
psi x 6.894757*E+00	= kPa

*Conversion factor is exact.

Table 1.–Treatment selection matrix.

Injectivity		Cement Squeeze		Polymer Squeeze	
bpm	psi	Slurry 1	Slurry 2	System 1	System 2
1	600-900	X			
2	300-600	X	X		
3	100-300		X	X	
4	0-100			X	X
5	0			X	X

Cement Slurry 1: Low fluid loss cement with expanding agent to improve bond.
Cement Slurry 2: Thixotropic, low fluid loss cement to aid in early squeeze pressure; foamed with 250 scf/bbl N_2.
Polymer System 1: Intermediate molecular weight polymer with low degree of hydrolysis and 24-hr working time.
Polymer System 2: High molecular weight polymer with high degree of hydrolysis.

Table 2.–Treatment summary for conformance focus area.

Well	Date Treated	Type	Treatment	Notes
EMSU 183	Nov-97	injector	squeeze Z1-2, perforate Z3, acidize Z3-5	squeeze only tested to 380 psi
EMSU 199	Nov-97	injector	squeeze Z1-2, acidize Z3-5	good squeeze; some backside communication during acid job
EMSU 201	Sep-97	injector	perf Z3, acidize wellbore, squeeze Z6	
EMSU 209	10/97	injector	squeeze Z2, acidize Z3-5	squeeze only tested to 430 psi, bled 150 psi in 10 min
EMSU 211	Mar-97	injector	386 bbl MARCIT Z2, clean out and stimulate Z3-5	design 1500 bbl MARCIT; acid job broke into SA Z6
	May-98	injector	squeeze Z6, stimulate Z3-5	1 yr old MARCIT and cement leaked, several 100 psi in 5 min
EMSU 212	Nov-97	producer	squeeze Z1-2, stimulate Z3-5	
EMSU 225	Nov-97	injector	squeeze Z1, stimulate Z2-4	squeeze leaked; 555 psi to zero in 25 min
EMSU 226	Jul-97	injector	squeeze Z1, stimulate Z2-4	possible casing problem; very slight squeeze leak
EMSU 227	Jul-97	injector	squeeze Z1-2, stimulate Z3-5; add perforations	casing split during acid job (after squeeze)
EMSU 228	Jun-97	injector	squeeze Z1-2, stimulate Z3-TD	
EMSU 229	May-97	injector	squeeze Z1-2, add perforations, stimulate Z3-TD	squeeze bled 80 psi in 10 min
EMSU 237	Oct-97	injector	add perforations in Z3-4, stimulate Z3-5 (not completed in Z1-2)	
EMSU 238	Jan-98	producer	plug back to 3830 ft, stimulate openhole (3748-3830 ft)	
EMSU 239	Sep-97	injector	MARCIT/cement Z1-2, add perforations Z3-4, stimulate Z3-5	all perforations communicated during acid job; did not use MARCIT, only cement
EMSU 240	Jun-97	injector	squeeze Z1-2, stimulate Z3-TD	squeezed perforations leaked 500 psi to 0 in 5 min; acid job had behind pipe communication
EMSU 241	Jun-97	injector	squeeze Z1-2, stimulate openhole	test squeeze to 500 psi; lost 450 psi in 11 min.
EMSU 242	Jul-97	injector	squeeze Z1-2, stimulate openhole	test squeeze to 500 psi; no pressure loss
EMSU 243	Sep-97	injector	squeeze Z1, stimulate openhole	did not test squeeze
EMSU 244	Oct-97	producer	add perforations in Z2, plugback Z4 and lower Z3, stimulate Z1-upper Z3	
EMSU 245	Feb-98	injector	clean out and stimulate	
EMSU 255	Feb-98	injector	clean out and stimulate	could not get coiled tubing into hole, no clean out and stimulation
	Apr-98	injector	clean out and stimulate	
EMSU 257	Oct-97	injector	1060 bbl MARCIT/cement Z1-2, stimulate Z2a-5	communication during acid job, test squeeze to 315 psi; no bleed off
EMSU 258	Apr-98	producer	add perforations in Z3-4, stimulate Z3-4, squeeze Z1-2	test squeeze to 400 psi, no bleed-off
EMSU 259	Jan-98	injector	MARCIT/cement Z2, stimulate Z3-5	acid stimulation, then had well problems; tried several cement squeezes, finally successful; no MARCIT
EMSU 638	Dec-97	producer	add perforations, stimulate Z3-4, squeeze Z2	acid communicated behind pipe; test squeeze to 500 psi, no pressure loss
EMSU 261	Dec-97	injector	add perforations, stimulate Z3-5, squeeze Z1-2	had to repair casing leak before acid job; looks like squeeze perforations leaked a bit
EMSU 279	Dec-97	injector	stimulate Z3-5, squeeze Z2 and casing shoe	behind pipe communication during acid job; test squeeze to 500 psi; bled to 300 psi in 30 min
EMSU 280	Nov-97	producer	stimulate Z3-4	behind pipe communication during acid job
EMSU 282	Jan-98	producer	cleanout and stimulate	behind pipe communication during acid job

Table 3.–Injection well treatments through February 1998 for conformance diamond.

Well	Date Treated	% Injection into the Gas Cap		Injectivity (B/D/psi)	
		Before	After	Before	After
EMSU 183	Nov-97	79%	0%	0.34	0.32
EMSU 199	Nov-97	76%	0%	0.64	0.35
EMSU 201	Sep-97	45% Z6	0%Z6	0.58	0.08
EMSU 209	10/97	53%	0%	vacuum	vacuum
EMSU 211	Mar-97	72%	100% Z6	1.56	0.55
	May-98	100%Z6	no results yet		
EMSU 225	Nov-97	100%	38%	0.41	0.36
EMSU 226	Jul-97	42%	0%	0.98	0.7
EMSU 227	Jul-97	68%	21%	4.8	1.6
EMSU 228	Jun-97	21%	0%	0.65	0.9
EMSU 229	May-97	100%	19%	5	0.9
EMSU 237	Oct-97	0%	0%	0.6	1.3
EMSU 239	Sep-97	73%	17%	1.5	0.4
EMSU 240	Jun-97	68%	33%	1.7	1.2
EMSU 241	Jun-97	100%	0%	1.1	1
EMSU 242	Jul-97	87%	42%	1	1.3
EMSU 243	Sep-97	68%	10%	0.54	0.3
EMSU 245	Feb-98	well distributed	little change	1	no results yet
EMSU 255	Feb-98	well distributed	little change	1.08	no results yet
	Apr-98				no results yet
EMSU 257	Oct-97	100%	0%	1.2	0.4
EMSU 259	Jan-98	100%	0%	6	2
EMSU 261	Dec-97	50%	0%	0.97	0.39
EMSU 279	Dec-97	100%	0%	0.8	0.53

Table 4.–Production well treatments through February 1998 for conformance diamond.

Well	Date Treated	Water Production Rate (BWPD)		Oil Production Rate (BOPD)	
		Before	After	Before	After
EMSU 212	Nov-97	960	1170	13	13
EMSU 238	Jan-98	320	420	20	26
EMSU 244	Oct-97	155	161	14	12
EMSU 258	Apr-98	870	no results yet	2	no results yet
EMSU 638	Dec-97	1400	163	33	58
EMSU 280	Nov-97	370	390	11	11
EMSU 282	Jan-98	400	600	30	27

Table 5.–Preliminary economics.

Preliminary Economics	
24 jobs to date	$43,000 / job
Total investment	1.0 MM$
After tax NPV @ 10%	1.8 MM$
Reserves	1.9 MMBO
% OOIP	2.1%
Rate of return	56%
DPI @ 10% discount	4.7
Payout	42 months

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Water and Gas Control Gel Placement

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Abstract

The success of treatments to control non-productive water and gas depends on knowledge of water entries at the wellbore and the selection of a proper placement technique. Often, the selection of the gel placement method is based on past field experience. There has been no engineering approach and guideline for field use.

This paper examines the effects of fluid and reservoir properties on gelant invasion and dispersive flow behavior in heterogeneous formations. The application of bullheading, mechanical wellbore isolation, and the dual-injection technique is evaluated with reservoir simulations. Key parameters dictating the choice of an appropriate gel placement technique are identified. Furthermore, the need for a dual-injection method for complicated well completions (gravel-pack, poor cement integrity, and near wellbore fissures) is elucidated. Case histories illustrate application of each injection method.

Simple bullhead injection is acceptable when very high permeability and saturation contrasts exist and a large pressure drop is available to breakdown gel damage in oil productive intervals or when reperforating the oil zone is an option. Bullheading is also appropriate when self-selective fluids are employed, although the use of self selective fluids has had mixed results with the exception of flowing gels that selectively invade fractures. More elaborate bullhead techniques utilizing overflushes or alternating stages of immiscible fluids may improve the placement selectivity under certain conditions. Mechanical isolation of the target interval is recommended when the wellbore has good casing and cement, there are no nearwellbore fissures and if one or two water or gas entries have been identified. The simultaneous injection of gelant and a protective fluid, i.e., the dual injection technique, is recommended when there are no horizontal barriers, the vertical permeability is high, or the adjacent oil bearing zones are thin.

Introduction

Crosslinked polymer gels are commonly used to treat production wells with excessive unproductive water or gas flows and injection wells with poor injection profiles. The decision to utilize a crosslinked polymer gel to partially or completely plug fractures or high permeability layers is made after the treatment has been designed; a process that requires verification of the water production mechanism and identification of the offending interval. Following the design step, one must carefully choose an injection technique to deliver the gelant to the intended location. A technique that minimizes the invasion of delayed crosslink polymer solutions (gelant) into adjacent productive intervals is of paramount importance for a successful treatment.

A common, but inappropriate field criterion used to choose among the various placement techniques has certainly led to numerous treatment failures. The criterion is that one bullheads gelant into the formation when the water entry is ill-defined and one employs a diverse combination of packers, bridge plugs, sand, and cement to limit gelant invasion to a specific interval when the water entry has been located.

Numerous papers have been published within the past decade that investigate the placement of gelants in the formation surrounding wellbores[1-5]. The majority of the conclusions presented in these papers are for the case of non-communicating layers under the assumption that the gelant penetration in porous media can be simulated by incorporating non-Newtonian rheological models into standard reservoir simulators. Other work indicates that there are important phenomena, such as bridging-adsorption[6] and the filtration of gel aggregates[7,8], that can preferentially inhibit gelant penetration into low permeability zones. Nonetheless, studies that simulate gelant flow as Newtonian or non-Newtonian fluids are valuable and illuminate the need for using the proper placement technique for the gelants

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commonly used today. The following is a brief review of these papers.

Placement of Water and Gas Control Gels in Non-Communicating Layers

Commonly, gelants are injected into the formation using the fullbore (or bullhead) placement technique. Bullheading is generally acceptable for selectively plugging fractures but is risky for matrix treatment of high conductivity layers. Gel systems designed for matrix treatment are formulated such that crosslinking occurs after placement. Thus, the gelant is capable of penetrating all exposed porous media. Using mathematical relationships for fluid flow into adjacent, non-communicating layers in oil bearing reservoirs, Seright[1] identified optimum conditions for minimizing the degree of penetration into productive intervals during the fullbore injection of Newtonian fluid in injection wells. The optimum conditions were that high mobility gelants be injected into reservoirs containing fluids with high water-oil mobility ratios. Furthermore, the most permeable layer should be watered-out but the waterfronts in the other layers be far from the production well. Unfortunately, the ratio of the depth of gelant penetration into the low permeability zone (LPZ) to the depth of penetration into the high permeability zone (HPZ) for radial systems was at least as large as the quantity, $(K_H/K_L)^{-0.55}$, even under the optimum conditions. Many of today's delayed gelant systems, including polyacrylamide crosslinked with trivalent chromium, may have less selective invasion into heterogeneous formations because of their relatively low mobility (assuming Seright's model can represent the invasion of polyacrylamide gelants into porous media). Thus, some technique that minimizes gelant contact with productive intervals should be employed for injection well profile control treatments to protect LPZs.

Similar statements can be made regarding the placement of gelants in production wells[2]. Liang et. al., also showed that naturally occurring saturation disparities between layers can improve selectivity. The higher the water saturation in the high permeability zone, the less gelant penetrates into the low permeability layers. Despite this phenomenon, the ratio of the LPZ depth of penetration to the HPZ depth of penetration is still substantially greater than the value, K_L/K_H, even in the most extreme case where S_w in the HPZ is 1.0.

One unintended consequence of production well treatments is loss of oil production. One source of lost production is that any oil production from the HPZ will be lost after that zone is plugged. The second source of production loss is from the low permeability zones that receive gelant. It has been shown that LPZs loose oil productivity when gelant invades *even if the gel does not affect the oil phase relative permeability curve*[2]. The fractional flow of oil and water remain the same in the treated and untreated portions of the layer. However, because the water relative permeability decreased, a new fractional flow curve exists for the treated portion of the layer. The result that is described by Liang et. al., is that the water saturation must increase in the treated portion of the LPZs to accommodate the prevailing water fractional flow. As a result, the relative permeability to oil and the oil productivity of the LPZ will be reduced unless the oil saturation is very high initially (very low water fractional flow). Liang's conclusions were based on a gel system that only reduces the permeability to water. Actual oil productivity losses will be greater because currently available systems also reduce permeability to oil[2].

Numerical investigations conducted with non-Newtonian fluids indicated that with very few exceptions the non-Newtonian fluids had worse placement characteristics than low viscosity Newtonian fluids[3]. The few cases that did improve the placement selectivity did so only marginally.

Another numerical study evaluated the role of dispersion and diffusion on gelant placement[4]. Gelants employed for matrix treatments will have delayed crosslinking reactions to allow for their penetration into porous media. Reactant diffusion after shut-in and before the crosslinking reaction has gone to completion will deplete the concentration of reactants. Sufficient reactant depletion can prevent a damaging gel from forming. Seright's calculations show that although this phenomenon can occur, the length of the gelant bank rendered ineffective by diffusion is extremely small, scaling approximately by the following equation,

$$L_m = 3.62(Dt_g)^{0.5} \qquad (1)$$

where L_m is the length of the mixing zone, D is the apparent diffusion coefficient of a reactant in porous media, and t_g is the gelation time. Similarly, the mixing length for dispersion is approximated by the following equation,

$$L_m = 3.62(\alpha L)^{0.5} \qquad (2)$$

where α is the dispersivity of the porous media (approximated by $\alpha=0.051L^{1.13}$ for α and L expressed in feet) and L is the original length of the gelant bank. The conclusion is that although dispersion and diffusion can affect the strength of gel plugs in laboratory experiments, they have minimal effect on real systems where depths of penetration are large. A plot is presented in Seright's paper showing the maximum allowable depth of gelant penetration into the HPZ that enables dispersion and diffusion to prevent gelation in LPZ layers under a given set of assumptions[4].

It was also shown that inert postflushes cannot be exploited to minimize LPZ damage when gelants are injected using bullhead techniques[4]. Postflushes with the same mobility as the gelant will result in almost equivalent gelant bank damage in each zone, i.e., if the gelant bank length in the LPZ is reduced by a factor of two then the gelant bank in the HPZ would also be reduced in length by a factor of two. Furthermore, high mobility postflushes designed to finger through gelant banks will actually break through the HPZ gelant bank before it fingers through the LPZ gelant bank[4].

The conclusions in the aforementioned papers were all based on the assumption that the gel residual resistance factors (F_{rr}) are independent of rock permeability. That is, the ratio of the resistance to water flowing through treated rock to the resistance to water flowing through untreated rock, $(Q/\Delta P)_{treated}/(Q/\Delta P)_{untreated}$, is independent of rock permeability. Recent studies have shown this to be false[5,9]. Interestingly, different gels gave different trends. The strongest gels, those that effectively filled and plugged the entire pore space, had F_{rr}s that were independent of permeability. The permeability of all rocks treated with these strong gels was reduced to the microdarcy range, i.e., the permeability of the gel itself. Weak gel formulations, those that were only effective at plugging a fraction of the porosity, had F_{rr}s that decreased with increasing rock permeability. The result of these findings suggest that the need for zone isolation is definitely not eliminated for weak gel formulations and probably not eliminated for strong gel formulations. Weak gels require isolation because they are more effective at plugging LPZs than HPZs. Strong gels should have zone isolation because the treated rock permeability would cause unacceptably low productivities or injectivities.

Most of the gel systems currently applied for water or gas shut-off and for conformance control, breakdown when subjected to excessive stress. This breakdown results in an irreversible F_{rr} increase (F_{rr} will never recover to unity, however). As a result, there are conditions where gelant invasion and subsequent damage of LPZs may be acceptable[10]. Acceptable conditions occur when the barrier in the LPZs fails at lower drawdown than the HPZ barrier *and* the F_{rr} of the failed barrier is substantially less than the F_{rr} in the HPZ. There are field case histories that exhibit characteristics suggesting gel damage to LPZs was overcome through barrier breakdown[11].

Bullhead application of gels in fractured wells results in substantially better selectivity than the matrix cases discussed above. However, there are some placement problems that may be encountered. Seright showed that gelants can leak-off into the porous media surrounding a fracture[12]. Thus, systems should be designed so that the gel has formed some structure to resist leak-off yet still remain fluid enough to flow down the fracture under reasonable pressure gradients. Alternatively, a particulate fluid loss additive may be employed to minimize leak-off[12]. One interesting observation was that delayed gelants can undergo gravity segregation with oil during shut-in, thus opening the possibility of selectively plugging the bottom of fractures that intersect water zones.

The overwhelming conclusion of these papers is that simple bullhead placement techniques can lead to severe damage to LPZs that are in communication with the wellbore. General exceptions include scenarios where fractures are targeted for treatment or the layers targeted for matrix treatment have permeabilities more than one order (and preferably two orders) of magnitude greater than the productive LPZs.

Mechanical isolation of the HPZs is an effective solution for protecting LPZs when the formation is made up of non-communicating layers. However, questions remain for other cases of practical interest. Under what conditions can one apply mechanical isolation for communicating layers? Are there other field proven techniques that can improve the effectiveness of bullheading? What are the operational characteristics of some alternative placement methods designed to minimize LPZ damage?

The objective of the remainder of this paper is to illustrate the impact of some key reservoir properties and wellbore conditions on the placement of gel into macroscopically heterogeneous formations containing communicating layers; conditions that were not discussed in detail in the aforementioned studies. Three different gel injection techniques will be examined: 1) **bullhead**, 2) **mechanical isolation**, and 3) **dual-fluid injection**. Recommendations and useful guidelines are provided for effective application of each gel injection technique. Additionally, a description of field observations during the implementation of each gel placement technique is provided. The paper is concluded with a practical guide for selecting the most appropriate placement technique in today's oil field.

Placement of Water and Gas Control Gels in Communicating Layers

Three injection techniques were studied using a commercial black oil simulator. The simulations were performed on a single well, radial model. The model formation contained three different permeability layers in hydraulic communication; a high permeability zone (2 feet thick) in-between two low permeability zones (20 feet thick each). The porosity of all zones was 0.12 and the low permeability zone permeability was always 1 mD. The gelant was represented by a Newtonian fluid and was injected into a 100% water saturated formation. The gelant profiles are depicted by colored/shaded contours in the figures. Fractional gelant saturations less than 0.2 were considered to be too low to cause significant flow restriction. In other words, porous media with gelant saturations above 20% are considered to have damaging gelant invasion.

The following parameters were studied: the permeability contrast (K_H/K_L), the vertical to horizontal permeability ratio ($F_K = K_v/K_h$), and the viscosity ratio of the injected gel to the original formation water (μ_g/μ_w). The effect of macroscopically heterogeneous water saturations on the gelant invasion is important as discussed previously, but is neglected here. Furthermore, the effect of the injection velocity on gelant dispersion was not considered as dispersion was previously shown to be inconsequential[4].

Results and Discussion

Bullhead Gel Injection. The great risk of this injection method is the strong possibility of gel invading and damaging all open intervals. Some cases exist where bullhead injection may be the only option. These cases involve reservoir conditions such as formations that contain many intertwining layers with very large permeability and water saturation contrasts. Nevertheless, simple bullhead injection is the least versatile and least reliable placement method.

Consider the series of injection profiles depicted in Figure 1 for a formation with a K_H/K_L of 100 and $F_K = 0.01$. Initially, the majority of the gel enters the HPZ and due to mixing or low depth of penetration, minimal gelant invades the low permeability zones (LPZ). The gelant can invade approximately one foot into the HPZ without damaging the LPZ. As injection continues, damaging amounts of gelant invade the adjacent LPZs. The distance the gelant can invade the HPZ without damaging the LPZs is critically dependent upon the degree of macroscopic heterogeneity. Under the conditions stated above, it was observed that the depth the gelant can penetrate the HPZ with minimal LPZ entry is proportional to $\ln(K_H/K_L)$.

Low vertical to horizontal permeability ratios yielded gelant invasion results similar to non-communicating layers (there was minimal vertical spreading of the gelant). High vertical permeabilities ($F_K = 1.0$) have a negative impact on the gelant invasion only if the permeability ratio (K_H/K_L) was 10 or less.

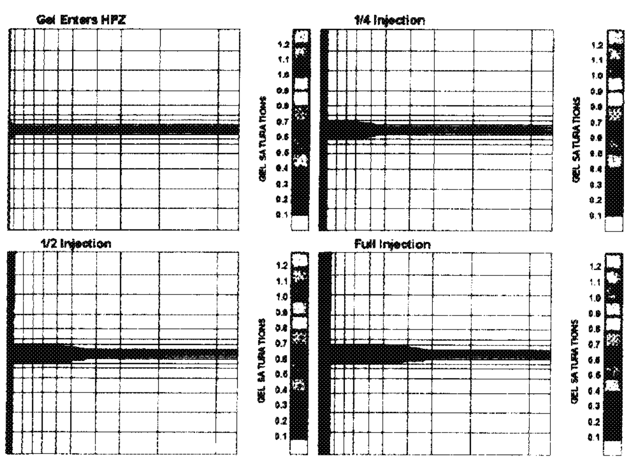

Figure 1. Bullhead gel injection, $K_H/K_L = 100$.

The adverse affect was that the gelant slug in the HPZ spread laterally into the adjacent LPZs and reduced the already minor selective HPZ invasion depth. The aforementioned results are the worst case scenario. Relative invasion selectivity can be improved if the HPZs have very high water saturations and the LPZs have very low water saturations. Relative permeability effects will compound the absolute permeability contrast in such a case.

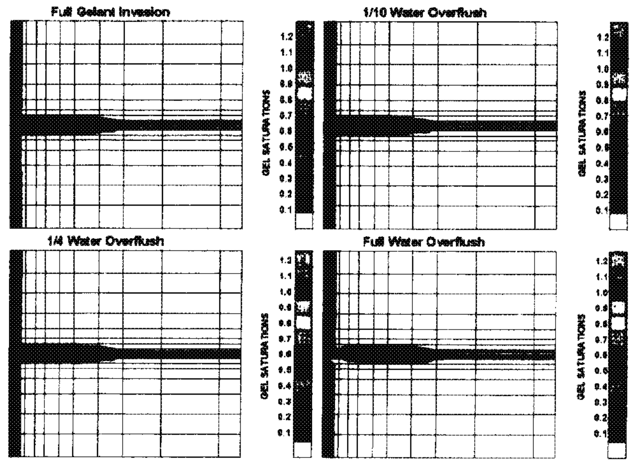

Figure 2. Water overflush opens pathway from LPZ to the wellbore.

To minimize LPZ damage and enhance HPZ placement selectivity, strategies that overflush the gelant have been proposed to prevent gel from shutting off all inflow into the well[13]. Figure 2 shows a sequence of gelant saturation profiles during the gelant overflush. Injected water displaces the gelant in the HPZ away from the wellbore faster than in the LPZ. As a result, produced fluids can flow from the LPZ into the HPZ and circumvent the LPZ near wellbore gel damage. One must exercise caution in applying an overflush such as the one described here. Improperly designed overflushes may render the treatment ineffective.

Mechanical Isolation. Gel damage to LPZs can be significantly reduced if the gelant entry is mechanically limited to the HPZ. Figure 3 shows the progressive invasion of gelant into a formation with $K_H/K_L = 5$, $\mu_g/\mu_w = 1.0$, and $F_K = 0.01$. The LPZs are largely gel free with the exception of some near wellbore lateral spreading.

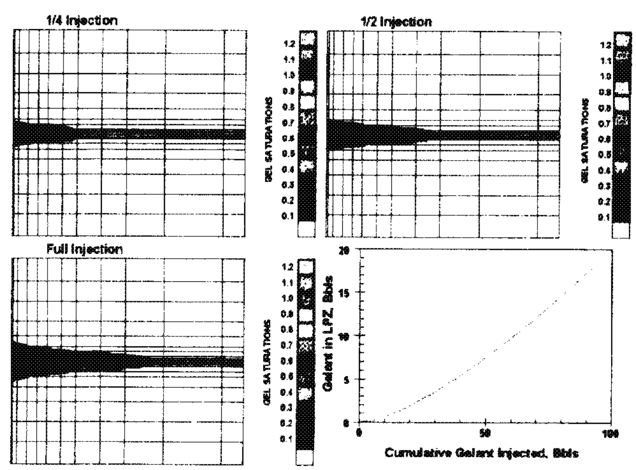

Figure 3. Mechanical isolation, $K_H/K_L = 5$, $F_K = 0.01$.

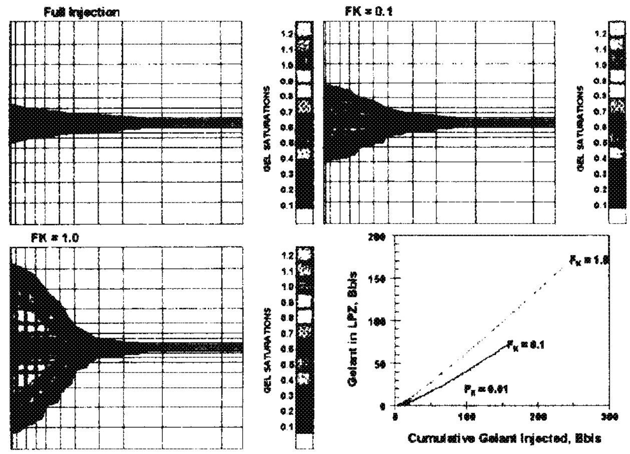

Figure 4. Effect of F_K on lateral gelant spreading.

The magnitude of the lateral spreading increases with increasing F_K as can be seen in Figure 4 for F_K = 0.01, 0.1, and 1.0. Not only does the gelant invade and damage the adjacent low permeability zones for higher F_Ks, but the volume required to achieve a specified depth of penetration increases. For example, the following gelant volumes were required to achieve a 24 foot penetration depth: 1) 95 barrels when F_K = 0.01, 2) 135 barrels when F_K = 0.1, and 3) 240 barrels when F_K = 1.0.

This lateral spreading makes simple volumetric gel calculations, such as those described by Bang[14], unsuitable for estimating the volume of gel required to treat a well. The plot on the lower right corner of Figure 4 shows the volume of gelant that spread laterally into the LPZs versus the total volume of gelant injected. The difference between the two numbers is the volume of gel that actually invaded the HPZ. For very high F_K, the volume of gel lost to lateral spreading is greater than the volume of gel in the HPZ for this model reservoir.

The lateral spreading decreases as the permeability contrast, K_H/K_L, increases. In fact, when K_H/K_L = 1000 and F_K = 1.0, the maximum lateral gelant spreading for a 24 foot deep plug was approximately 1.2 feet as compared to approximately 13 feet when K_H/K_L = 5 and F_K = 1.0. The acceptable amount of lateral spreading during gelant placement depends on the location and thickness of the LPZ layers. When the LPZs and HPZs are in communication (the case considered in this paper), lateral spreading will always be detrimental to the LPZ. However, a substantial fraction of the LPZ may be unaffected by the gel if the LPZ is thick enough. For example, 13 feet of near wellbore lateral spreading may be acceptable if the LPZ is 100 feet thick. Similarly, lateral spreading of any amount could shut off thin LPZs.

Dual Fluid Injection: Gelant injection using mechanical isolation can reduce gel damage to adjacent low permeability zones when F_K is low and/or K_H/K_L is high. Furthermore, mechanical isolation can be very effective if impermeable stringers or thick non-productive intervals separate the high permeability water sources from the LPZs. However, mechanical isolation is only effective if one can achieve good wellbore control and there are no vertical channels behind the casing. Unfortunately, a large majority of wellbores have some problem that reduces the effectiveness of mechanical isolation. Problems include open hole intervals, a poor cement bond, a gravel pack, or near wellbore formation fissures.

Figure 5 depicts gelant invasion into a heterogeneous formation that has such a near wellbore fissure/gravel-pack/poor-cement-bond completion problem. The "fissure" extends only into the upper LPZ. The gelant readily invades both the HPZ and the upper LPZ despite mechanically isolating the HPZ.

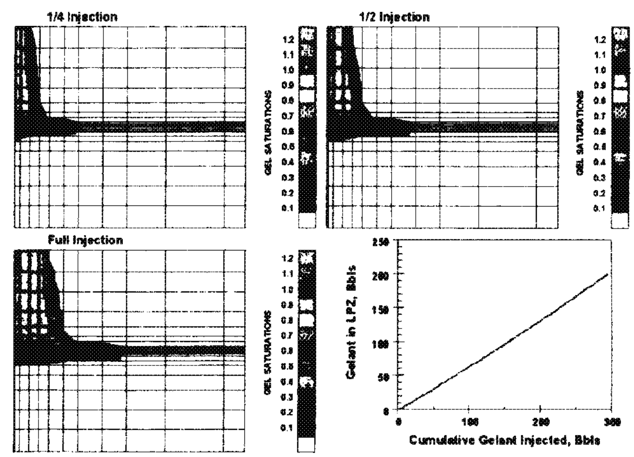

Figure 5. Gel saturation profile during injection into the middle layer of a wellbore that has a channel behind the pipe.

An alternative injection strategy simultaneously injects a protective fluid (water in this case) down the annulus (into the upper LPZ) and injects the gelant down tubing (into the HPZ). The lower LPZ, which has no near wellbore fissures, is mechanically isolated using a cast iron bridge plug or sand topped off with calcium carbonate flour.

There are two ways to control gelant placement during this type of treatment. One is to set a packer between the LPZ and the HPZ. The gelant is injected below the packer and the protective fluid is injected above the packer. If one balances the downhole injection pressures (after subtracting the hydrostatic head difference), there can be no vertical fluid flow between zones, thus each fluid will enter the formation at a specific and controlled depth. Alternatively, the interface between the protective fluid and the gelant can be monitored using a tracer in the protective fluid and a wireline tool. The interface position can be controlled by adjusting the injection rates to balance the injection pressures. Plahn et. al., provide a detailed discussion on these two techniques[15].

The simulation results are shown in Figure 6 for this dual-fluid injection technique. There is no gelant invasion into the upper LPZ. This dual fluid injection technique shall be recommended whenever there is behind the pipe communication and/or poor wellbore control. This technique incurs an additional cost of pumping a protective fluid with varying viscosity. Other than water with or without some chemical additives, the protective fluid can be non-aqueous such as diesel or lease oil. It can also be foam.

Interestingly, the parameter sensitivity study revealed that K_H/K_L, F_K, and μ_g/μ_w all influence the volume of the protective fluid required to prevent gelant invasion into the upper LPZ . Figure 7 shows how the ratio of the volume of injected protective fluid to the volume of injected gel (V_{pf}/V_g) varies with each parameter. The injected fluid ratio (V_{pf}/V_g) increases with increasing μ_g/μ_w, increasing F_K, and decreasing K_H/K_L.

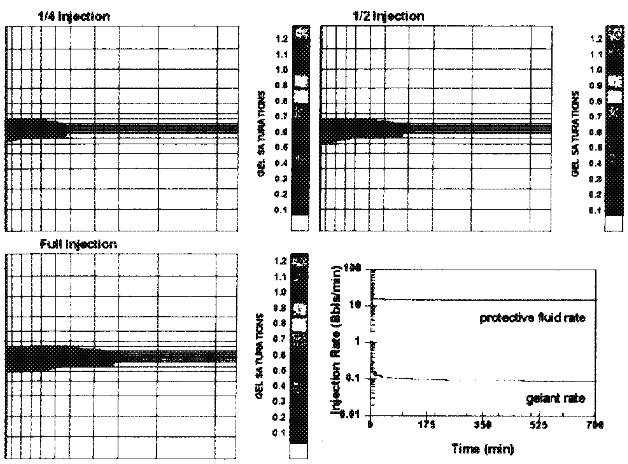

Figure 6. Dual injection of a protective fluid into the upper layer (low permeability) and gelant into the middle layer (high permeability) of a wellbore that has communication behind the pipe.

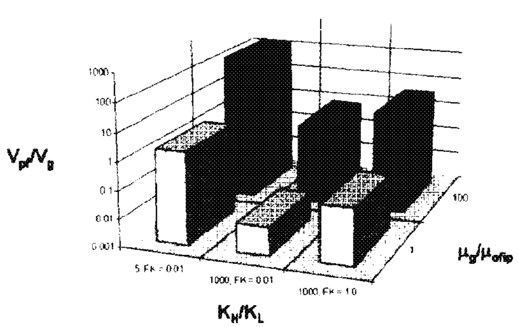

Figure 7. Ratio of the volume of injected water to injected gel (V_{pf}/V_g) using a dual fluid placement technique.

The previous sections present some theoretical aspects of the three most common gelant placement techniques. Satisfactory gelant placement can be achieved through application of these techniques or application of variations of these techniques. The primary factor in choosing a placement technique should be the ability of that technique to deliver the gelant selectively to the target zone. However, there are numerous operational issues that can take precedence over the primary factor. Table 1 presents some operational advantages and disadvantages of the three placement techniques.

Table 1. Overview of three common gelant placement techniques.

Placement Technique	Advantages	Disadvantages
Bullhead	Operationally simple Works well for fractured formations	Low pressure, low permeability layers will be damaged No control over fluid placement
Mechanical Isolation	Provides wellbore control of fluids Very effective for non-communicating layers or cases where large distances separate layers Can be used for low K_H/K_L if F_k is very small (F_k<0.01). Can be used for any F_k if K_H/K_L is very large (K_H/K_L>100).	Requires good casing, good cement Tools must be reliable More complicated workover procedure Difficult to apply in openholes
Dual Fluid	Provides wellbore control of fluids for complex completions or poor wellbore mechanical integrity Works well in openholes	Can only treat one HPZ at a time May be operationally difficult Fluid flow in formation or deep fractures may be difficult to predict or control

Field Implementation of Placement Techniques and Observations

Bullhead Injection. Bullheading is the most frequently used placement technique in the field despite some of the limitations discussed previously. The reason is due to existing mechanical problems with the wellbore completion, operational limitations and because the treatment cost for implementing mechanical isolation or dual-fluid placement techniques may be prohibitive for wells with low productivity.

A recent paper provides good bullhead placement case histories[16]. Gelant was bullheaded into a well with one major sandstone layer that contained three distinct productive intervals. The top interval was low permeability and low productivity. The middle interval was oil productive with moderate permeability and the bottom, watered-out interval was very high permeability. These three intervals possess a large absolute permeability contrast (K ratio > 10) and a large water saturation contrast. A total of 2,600 Bbls of gel fluid was bullheaded into the formation. The injectivity during the treatment was monitored using a modified Hall Plot which indicated a rapid increase of the pressure function at the very end of the treatment. The well took some time to clean up after the treatment. The oil rate doubled and the WOR decreased from 32 to 10.

Other more sophisticated bullhead techniques have also been employed. Conformance control treatments in Prudhoe Bay were designed to exploit artificially induced temperature gradients to control gelant invasion[17]. The formation was conditioned by injecting cold water prior to gelant injection. The thief zones become cooler than the adjacent low permeability zones. A properly formulated gelant remains fluid as it invades the HPZ, whereas gelant that invades the LPZs heats up rapidly, crosslinks and becomes immobile, thus minimizing LPZ invasion. Another operator has successfully treated gas wells with alternating slugs of gelant and nitrogen[18]. The purpose of the nitrogen was to re-establish gas permeability around the wellbore. Finally, there is some field evidence supporting the phenomenon of gel barrier breakdown due to high drawdown improving bullhead treatments[11]. Wells that were subjected to a high drawdown following bullhead gelant placement had a more complete oil production rate recovery than those subjected to a low drawdown. Another important factor reported by Lane and Sanders is that the high drawdown wells intersected faults or hydraulic fractures, whereas the low drawdown wells were matrix treatments. The gelant invasion into fractures is much more selective than into heterogeneous matrix so it is plausible that a short gel bank that invaded a LPZ broke down due to exposure to excessive drawdown.

Field Observations During Bullhead Gelant Injection. The Eunice Monument South Unit (EMSU) produces primarily from the Grayburg formation in southeast New Mexico. The Grayburg formation is broken into 6 zones between 30 and 100 feet thick. Each layer contains horizontal laminations or stringers of different permeability. The majority of the formation is dolomite with a permeability to oil of 1 to 20 mD and a reservoir temperature of around 95°F. The stringers have horizontal permeabilities as high as several Darcies; their vertical permeability is very low. The reservoir was produced by primary production until the oil production rate fell due to pressure depletion. A waterflood was initiated in 1987, and by 1988 the full unit was under waterflood. Many wells had a poor waterflood production response. The response was characterized by water cycling through the high permeability stringers which handicapped the pressure maintenance program and caused high WORs.

The operator is working to minimize the water cycling to achieve several goals: 1) increase the reservoir pressure, 2) divert injected water into the unswept low permeability zones, and 3) extend the life of marginal wells.

Production well EMSU 435 was drilled as a replacement well; it was completed on 6/1987. It is a cased hole and has been perforated between 3838' and 3966'. Initial production was 14 BOPD and 135 BWPD. The latest production log indicated 286 BFPD was produced between 3838' and 3861' and 330 BFPD were flowing downwards (crossflow into a lower pressure layer) from the same interval. The well was pumped off in 1994 and a production test resulted in 9 BOPD and 600 BWPD. An advanced production history analysis utilizing Diagnostic Plots[19] indicated rapid layer breakthrough after the well was put on waterflood.

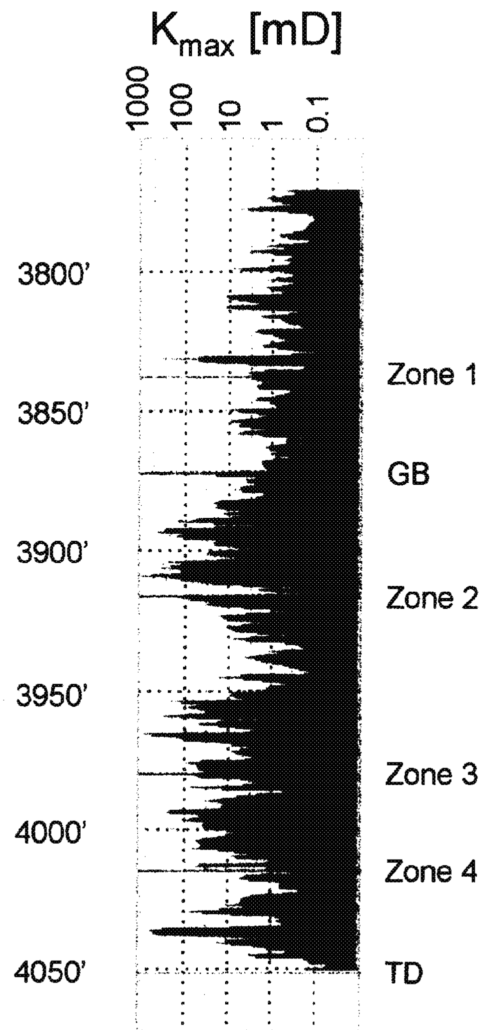

Figure 8. Permeability data from cores obtained from EMSU 447 (offset of EMSU 435).

Production profiles in EMSU 435 indicate that 100% of the produced fluid originates from Zone 1 (3840' to 3880'). Core data in the diagonally offsetting producer EMSU 447 indicates the presence of high permeability streaks (>500 mD, see Figure 8) in the interval that correlates to Zone 1 in EMSU 435. Furthermore, injection profiles in offset injectors 436, 434, and 446 indicate the majority of injected fluid enters Zone 1. Despite this last observation, there was a low correlation between 435 and its offset injectors. Treating the offset injection wells was therefore eliminated as an option.

The original treatment design was to mechanically isolate the water producing interval (3880'-3888') and then inject a dilute delayed crosslinked polyacrylamide gelant to completely shut-off the water. This set of perforations yielded 60% and 100% of fluid entry in two previous production logs. Previous treatment experience at EMSU lead to the following treatment design: inject 1000 barrels of 5000 ppm polyacrylamide solution with a delayed crosslinking mechanism.

It was found that the offending interval could not be mechanically isolated during the pretreatment well conditioning. As a result, the 1000 barrel treatment was bullheaded into the formation at a rate of 1 BPM until BHP reaches 2700 psig (the rate could be reduced to maintain 2700 psig BHP). It was felt that this gel system would offer some permeability based selectivity because the high molecular weight polymer used would encounter difficulty penetrating the low permeability, unswept zones.

Injection profiles were measured at 100 barrel increments. The job would be terminated if the injection profile showed fluid entering perforations below 3920' (the goal was to confine polymer treatment to Zones 1 and 2). Table 2 shows several tracer runs; it was surprising that polymer never entered perforations below Zone 2 (other perforated intervals included 3925'-3930' and 3935'-3966'). However, it should be noted that the gelant was well distributed across three of the five top intervals. All 1000 barrels were injected and the injection rates were reduced during the job to maintain the maximum BHP.

Table 2. Polymer injection profiles. Values reported in the table are the percentage of the total flow that is entering a specific perforation interval.

Perforated Interval (Zone)	1st Run [100 bbls]	2nd Run [200 bbls]	4th Run [400 bbls]	5th Run [500 bbls]
3838'-3856' (Zone 1)	30%	20%	44%	19%
3868'-3872' (Zone 1)	0%	7%	0%	0%
3880'-3888' (Zone 2)	34%	18%	24%	12%
3890'-3908' (Zone 2)	0%	0%	0%	24%
3914'-3920' (Zone 2)	35%	54%	32%	45%
3935'-4059' (Zone 3-5)	< 1%	< 1%	0%	0%

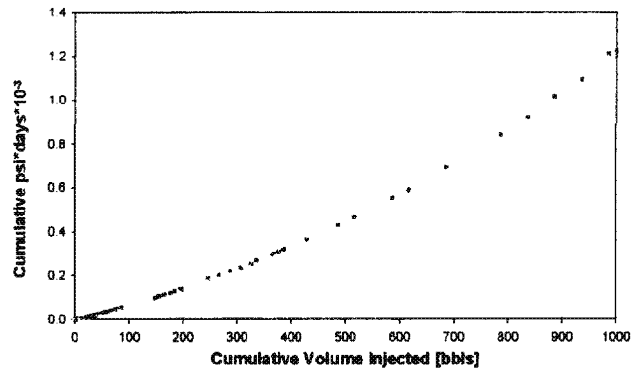

Figure 9. Hall plot during treatment of EMSU 435.

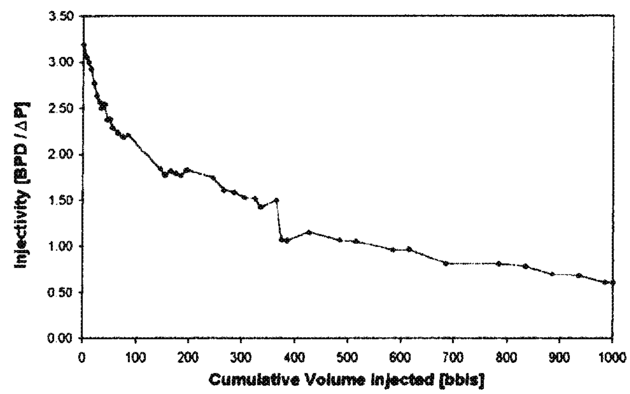

Figure 10. Injectivity decline during treatment of EMSU 435.

Figure 9 shows the Hall Plot generated during the treatment. This plot is routinely used to monitor the execution of conformance treatments. The slope of the plot increases if the viscosity increases or plugging occurs; the slope decreases for a variety of reasons including an increase in injectivity (fracturing) or a reduction of gelant viscosity. Alternatively, a plot of the well's injectivity decline during the treatment can be monitored (see Figure 10). Injectivity is the injection

Table 3. Production before and after treatment of EMSU 435.

Date (Pump Type)	Oil Rate [BOPD]	Water Rate [BWPD]	Fluid Level [Feet Above Pump]
9/5/95 (ESP)	9	565	125
10/8/95 (ESP)	9	565	125
11/6/95 (ESP)	8	560	219
Treatment (11/25/95)			
12/7/95 (Sucker Rod)	2	278	0
1/10/96 (Sucker Rod)	3	124	0
2/17/96 (Sucker Rod)	2	117	0
3/17/96 (Sucker Rod)	2	121	0
4/6/96 (Sucker Rod)	2	115	0

rate divided by the bottom hole pressure (BPD/psi). This plot is more sensitive to near wellbore changes in injectivity. The shape of the injectivity decline in Figure 10 can be reproduced by simulating the injection of a high viscosity liquid into a radial flow model. One can infer when gelant begins entering new intervals if the trace had more than one distinct sharp injectivity decline.

The majority of oil and water was shut-off as a result of this treatment. Although the loss of oil production was undesirable, it was the expected outcome. The well's production response is shown in Table 3.

Mechanical Isolation. There are many reports of successful treatments when mechanical isolation is employed. Field case histories reported by Ford and Kelldorf[20] indicate that treatment failures associated with the placement technique can be corrected using mechanical isolation in conjunction with fast setting gels. The authors describe that previous bullhead treatments resulted in unwanted damage to productive intervals. Mechanical isolation eliminated the damage to LPZs and a fast setting gel helped ensure that the entire high permeability zone was treated with gel (gelant was self diverting within the target HPZ). Robertson and Oefelein present case histories where 84% of the treatments were successful at modifying injection profiles when mechanical isolation techniques were used[21]. The noteworthy aspect of these treatments were that the mechanical isolation was achieved even though the wells contained gravel packs. The authors describe the use of a combination of packers and chemical seal rings to exploit the existence of impermeable shale barriers in the formation to achieve zone isolation. The packers were set in the screen at the same depth as a shale barrier. A chemical seal was placed in the gravel pack to create an impermeable seal in the gravel pack between the packer and the shale[21]. Sanders et. al., report 60% success at shutting off gas entries in Prudhoe Bay when gelants were placed using mechanical isolation[22]. Almost one third of the failures reported in their study occurred due to channels behind pipe (implying that mechanical isolation was not always effective).

Field Observations During Gelant Placement by Mechanical Isolation. A water shut-off treatment was executed on a production well from the Eunice Monument South Unit (field history was previously described). The well, EMSU 403, was drilled and completed on 5/6/1987. It is a cased hole and has been perforated between 3810' and 4038'. Initial production was 10 BOPD and 68 BWPD. Over a short period of time the water rate increased to the capacity of the pumping equipment and the oil rate fell to 1-2 BOPD. As a result, the well was shut-in beginning in mid-1993. Recently the fluid was pumped off and the well ESP tested at 10 BOPD, 2064 BWPD, and 14 MCFPD. Diagnostic plots indicated rapid layer breakthrough after the field was put on waterflood. Core data from this well indicates several high permeability streaks within the perforated intervals (3818'-3828', 3875'-3881', 3885'-3887', and 3916'-3926'. A production log run on 11/90 indicated 100% of the water production was from 3914'-3937'. A suite of 1992 logs run in the offset injectors indicates the majority of injection is going into Zone 1, with the remainder injecting into the lower Penrose (a formation that is above the Grayburg). Zone 2 is not being supported by injection.

The treatment was designed to completely shut-off all production between 3810' and 3930' and protect the unswept pay from 3930' to 4038'. This large interval was isolated by filling the wellbore with sand to 3940', and capping the sand with ten feet of calcium carbonate flour. A packer was set in the casing at 3800'. 1900 barrels of a 5000 ppm polyacrylamide solution with delayed crosslinking was injected into the open interval at roughly one BPM.

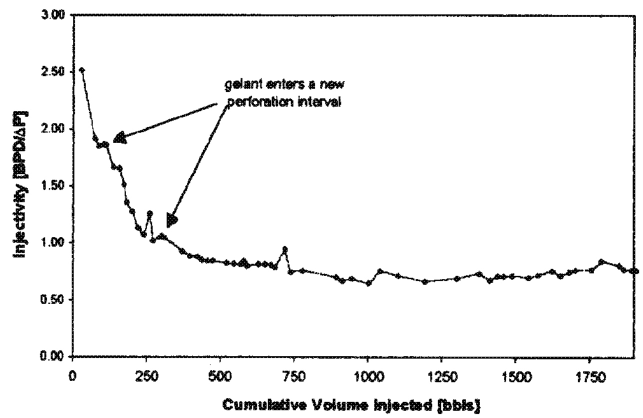

Figure 11. Injectivity decline during gelant injection into EMSU 403.

The Hall plot generated during treatment of EMSU 403 was almost a perfectly straight line. Figure 11 shows the injectivity decline during the treatment. There were two distinct plateaus in the injectivity decline early in the treatment, one at roughly 100 barrels, and one at around 250 barrels injected. Injection profiles taken during the job suggest an injectivity plateau with a subsequent rapid injectivity decline is an indication that gelant is entering a new high permeability zone. The first tracer run during the job (~50 barrels of gel injected) indicated that 72% of the fluid was entering the perforations at 3908'-3914' and 28% of the fluid was entering the perforations at 3920'. These perforations correspond to a series of 100 mD to 500 mD stringers. The injectivity rapidly declined and then leveled out at around 250 barrels of gel injected. A second tracer run at around 300 barrels of gel injected showed that almost 100% of the gel was entering a sequence of one Darcy stringers between 3875' and 3900'. The wireline unit broke shortly after this second tracer run. The injectivity rapidly declined for another 150 barrels (beginning around 300 barrels of gel injected), after which it remained almost constant.

Our interpretation of this injectivity decline is that the initial decrease was gel entering a thin high permeability stringer. The second rapid injectivity decline was gel sealing off the first stringer and beginning to enter the large group of very high permeability stringers. The injectivity reached a plateau around 750 barrels and remained there for the duration of the treatment because no new high permeability stringers were invaded.

The majority of oil and water production was shut-off. Although the lost oil production was undesirable, it was discussed during the job design phase and was expected. Table 4 shows the production response this well had to treatment.

Table 4. Production before and after treatment (EMSU 403 was shut-in, pre-job production was estimated by using a temporary electric submersible pump).

Date (Pump Type)	Oil Rate [BOPD]	Water Rate [BWPD]	Fluid Level [Feet Above Pump]
2/21/94 (ESP)	10	2024	32
2/22/94 (ESP)	10	2064	32
Treatment (10/25/95)			
11/13/95 (Sucker Rod)	1	297	0
1/16/96 (Sucker Rod)	2	165	0
2/22/96 (Sucker Rod)	1	109	0
3/17/96 (Sucker Rod)	2	133	0
4/02/96 (Sucker Rod)	1	121	0

Dual Fluid Injection. A dual fluid injection technique is described in the literature by Senol et. al.[23] A naturally fractured carbonate reservoir in Turkey suffered from progressive water encroachment from an underlying aquifer. Water channeled towards the wellbore through the fracture system. Attempts were made to seal the fracture network by adding a new set of perforations 12 to 40 feet below the original perforations and injecting a gelant. A packer was set in between the original perforations and the new set of perforations. Gelant was injected down the tubing into the new perforations and oil was injected down the annulus into the original set of perforations. This scheme successfully prevented gel damage to the original perforations (by preventing polymer from flowing up the fractures into the upper set of perforations). Although the placement technique prevented loss of oil productivity there were not many successful treatments. The reason for the low treatment success rate may be that the treatments were not sized properly, or that an inappropriate injection technique was used. Recent literature suggests that bullhead placement of gel in fractures is the most reliable technique for achieving a successful treatment[24]. Successful treatments in horizontal wells in Prudhoe Bay Alaska entailed pumping a polymer gel through coiled tubing to seal off a water conducting fault/fracture and pumping diesel through the coiled tubing/slotted liner annulus to suppress the gel back flow in the slotted liner/bore-hole annulus[16].

Field Observations During Dual Fluid Gelant Placement. A San Andres well Northwest of Levelland, Texas suffered from a bad primary cement job on a 5 ½" longstring; a fact that was confirmed by a cement bond log. A low vertical permeability barrier separates the oil productive San Andres formation from a known high water saturation zone. Initially the WOR was slightly higher than other wells in the field. However, the WOR continued to rise until it was abnormally high compared to the rest of the field. The well produced 10 BOPD and 900 BWPD at the time of treatment. Water was believed to be flowing from the high water saturation zone up into the wellbore through a high conductivity channel in the cement.

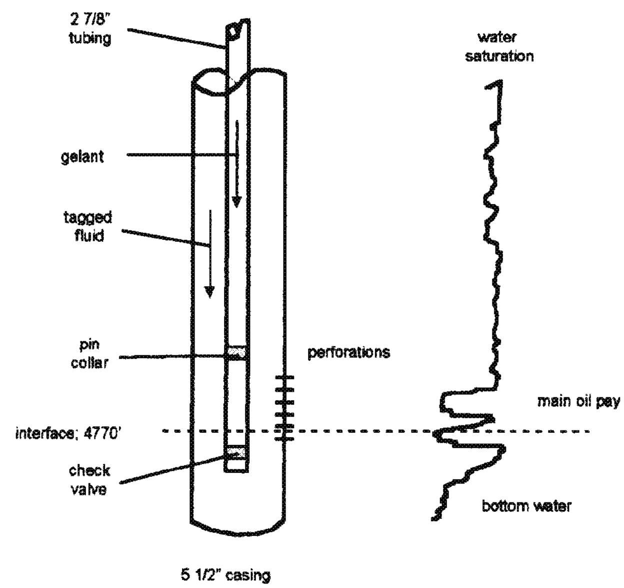

Figure 12. Wellbore schematic and log for dual fluid injection.

The saturation profile and well schematic are shown in Figure 12. The treatment was designed to place a relatively small volume of gelant into the bottom set of perforations to treat the channel that communicates with the bottom water. A protective fluid (water) was pumped into the remaining perforations to prevent gel from damaging them. A wireline tool was lowered down to the pin collar and a base log was run as a baseline. Injection was then established down the backside using fresh water spiked with an iodine tracer while fresh water alone was pumped down the tubing. The tubing rate was held constant at one bbl/min once the iodine water on the backside was seen at formation. The backside rate was varied to maintain an interface at 4770'. One half barrel per minute was found to hold the interface at 4770 ft.

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The injection rates were held constant as 1000 gallons of a delayed crosslinked gelant was pumped down the tubing. Twenty five sacks of cement was displaced to the end of the tubing leaving 0.9 barrels in the casing and 5 barrels in the formation.

This treatment ultimately failed because it was undersized. The injectivity decline during the gelant injection is shown in Figure 13. It is evident that the well's injectivity (BPD/psi) had only just begun to decline (compared to the baseline prior to gelant injection) by the time the total volume of gelant was injected into the formation. A subsequent, larger treatment was successful at reducing the water rate and increasing the oil rate.

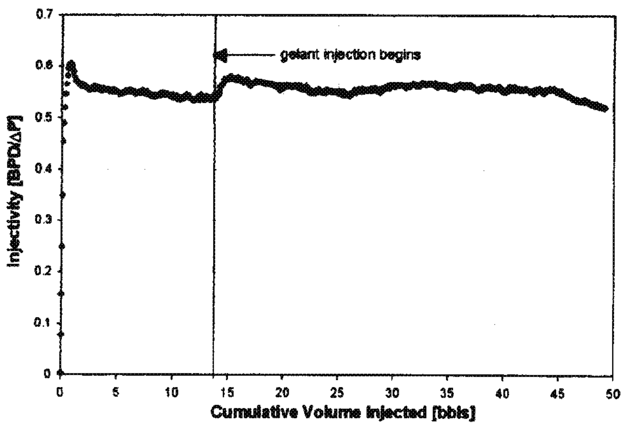

Figure 13. Injectivity decline during dual fluid placement of gelant.

Other Techniques

A placement technique involving alternate injection of gelant and Nitrogen gas appears to be very effective for controlling water influx into gas wells[18]. It is considered an elaborate bullhead technique. Fluids are injected with or without mechanical isolation. The Nitrogen gas not only displaces the gel but also fingers through the gel as a result of displacement instabilities arising from the large mobility contrast between the gelant and the gas. This unstable displacement enhances the placement of gel in the high water saturation channel and keeps the high gas saturation zone open to the perforations.

Figure 14 shows the changes in wellhead pressure during a recent job on a sandstone gas well with severe water entries. This treatment comprised of two stages of alternate gelant and Nitrogen gas injections. Only the first stage is shown in Figure 14. The wellbore was mostly gas filled at the start of the job. Pumping gel at a constant rate reduced the wellhead pressure by increasing the hydrostatic pressure on the formation. During this wellbore fillup period, the wellhead pressure versus time is a linear curve with a constant negative slope. The wellhead pressure began to increase due to viscous polymer fluid invasion into the reservoir formation once the gelant reached the perforation interval. Once Nitrogen gas injection began, the wellhead pressure increased logarithmically as the gelant was displaced into the formation and the liquid column height in the well decreased. The Nitrogen encountered a gel bank near the wellbore when it started to enter the formation. The gas began an unstable viscous fingering process which caused a sharp pressure increase (probably due to relative permeability effects). The wellhead pressure reached a maximum and then quickly reached a constant value after the gas traversed the gelant bank. A Hall Plot could not be used for evaluating the propagation of compressible fluids into the formation.

This placement technique may be applied for oil well treatments. Diesel or another light hydrocarbon fluid can be used instead of Nitrogen gas. Multiple stages of gelant alternating diesel may also aid in enhancing the oil and water saturation contrast which improves the efficacy of bullhead placement.

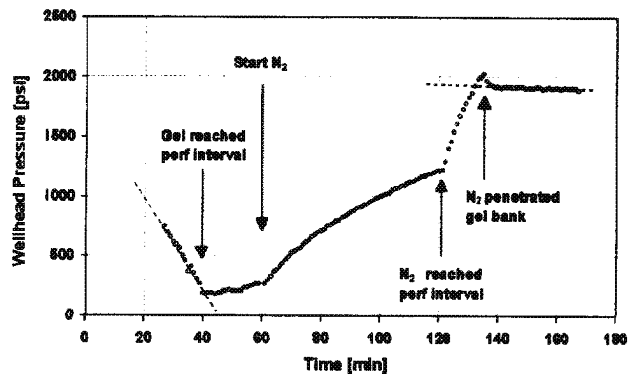

Figure 14. Treating pressure during alternating gelant and gas injection.

Recommended Placement Technique Selection Guide

This paper presented material that is useful for understanding how gelants invade and damage heterogeneous formations. Additionally, several case histories were reviewed that provide field experience for those inexperienced with the application of gelants for gas and water management.

The summary of this paper is in the form of rules of thumb that were derived from the previous discussion and a figure that presents a Placement Technique Selection Guide for gelants in heterogeneous formations (see Figure 15).

1. Simple bullhead gel injection can be utilized for the injection of small gel treatments with minimal gel damage to adjacent low permeability zones; the maximum high permeability zone penetration is proportional to $\ln(K_H/K_L)$. This method is impractical when $K_H/K_L < 10$.

2. Simple bullhead injection for deep gelant placement is acceptable as a last resort when very high permeability and saturation contrasts exist. Case histories with $K_H/K_L > 100$ showed gelant had greater selectivity than simulations indicate.

3. More elaborate bullhead injection techniques such as gelant alternating gas/diesel can improve the selectivity of gelant placement.

4. Bullhead injection is the placement technique of choice for self selective fluids. The injection of flowing gels into fractured formations is one example of this scenario.

5. Mechanical isolation of the offending interval should be used whenever possible, however, poor cement, gravel-packs, near wellbore fissures/fractures, and a high vertical permeability can minimize the control of the injected fluid. Furthermore, high vertical permeabilities in conjunction with a low permeability contrast cause substantial lateral spreading of the injected gelant.

6. The dual fluid injection technique is the placement technique of choice when any of the following conditions exist: a) openhole or gravelpack, b) communication behind the pipe, c) there are no horizontal barriers, the vertical permeability is high, and the permeability contrast is low, or d) the adjacent oil bearing zones are thin.

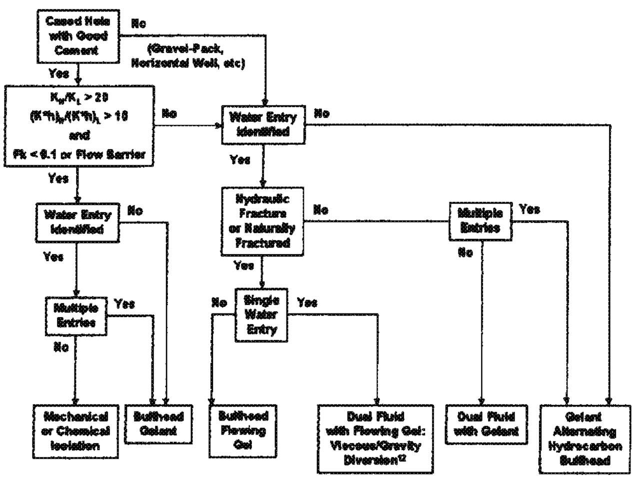

Figure 15. Placement technique selection guide. Gelant refers to delayed crosslinked polymer. Flowing gel implies a fluid that is at lease partially crosslinked during placement.

Notation

- D apparent diffusion coefficient in porous media [cm^2/s]
- F_K ratio of the vertical to horizontal permeability (K_v/K_h)
- F_{rr} residual resistance factor
- h zone thickness [m]
- K_h horizontal permeability [mD]
- $K{\bullet}h$ permeability, thickness product [mD•m]
- K_H high permeability zone's absolute permeability [mD]
- K_L low permeability zone's absolute permeability [mD]
- K_v vertical permeability [mD]
- L original length of gelant bank [m]
- L_m length of mixing zone [m]
- Q volumetric flow rate [m^3]
- S_w water saturation
- t_g gelation time [days]
- V_g volume of gelant injected [m^3]
- V_{pf} volume of protective fluid injected [m^3]
- α dispersivity of porous media [m]
- ΔP pressure drop [Pa/m]
- μ_g gelant viscosity [mPa•s]
- μ_{ofip} viscosity of the original fluid in place [mPa•s]
- μ_w water viscosity [mPa•s]

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Goodnight Cross Exhibit 3

WELL LOGS

API number:	30-025-37279			
OGRID:		Operator:	XTO ENERGY INC	
		Property:	EUNICE MONUMENT SOUTH UNIT	# 628

surface	ULSTR:	P/H/16	6	T 21S	R	36E
			2650 FSL		1085 FEL	
BH Loc	ULSTR:	P/H/16	6	T 21S	R	36E
			2650 FSL		1085 FEL	

Ground Level:	3566	DF:	3582	KB:	3583	
Datum:	KB			TD:	4622	

Land: STATE

Completion Date: (1)	
Date Logs Received:	5/9/2006
Date Logs Due in: (2)	

Confidential:	NO			Date out:		

Confidential period: 90 Days for State & Fee, 1 Year for federal

Date Due In: (1) is equal to Completion Date (1) + 20 days

Logs	Depth interval		
DSN/SDL	200	4548	Spectral Density Dual Spaced Neutron
DLL/MSFL	1430	4619	Dual Laterolog Micro Sperically Focused Log
			Borehole Volume Calculation
	0	4091	Radial Cement Bond

OCD TOPS

Rustler	1256	Strawn				
Tansill	2530	Atoka				
Yates	2714	Morrow				
7R						
T. Bowers Sd						
B. Bowers Sd						
Queen	3330					
Penrose						
Grayburg	3631					
San Andres	4087					
Glorieta						
Tubb						
Drinkard						
Abo						
Wolfcamp						

Goodnight Cross Exhibit 4

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4833 SARATOGA #624 CORPUS CHRISTI TEXAS 78413
P.O. BOX 2993 ROCK SPRINGS WYOMING 82902
OFFICE (432) 563 0084 --- 24 HOURS (800) 578 1006

Company:	XTO ENERGY, INC.
Well:	EMSU #746
Field:	EUNICE MONUMENT SOUTH
API:	30-025-37356
Location:	1380'FNL & 10'FEL SEC 15 T 21 S R 36 E
County:	LEA
State:	NEW MEXICO
Logger:	J BAKKE R GONZALES
Interval:	2800' To: 5455'
Date:	8/31/05 To: 9/06/05
Unit:	19
Well#:	3582
Kelly Bushing:	3583'
Phone:	(432)528 5819
Ground Level:	3567'

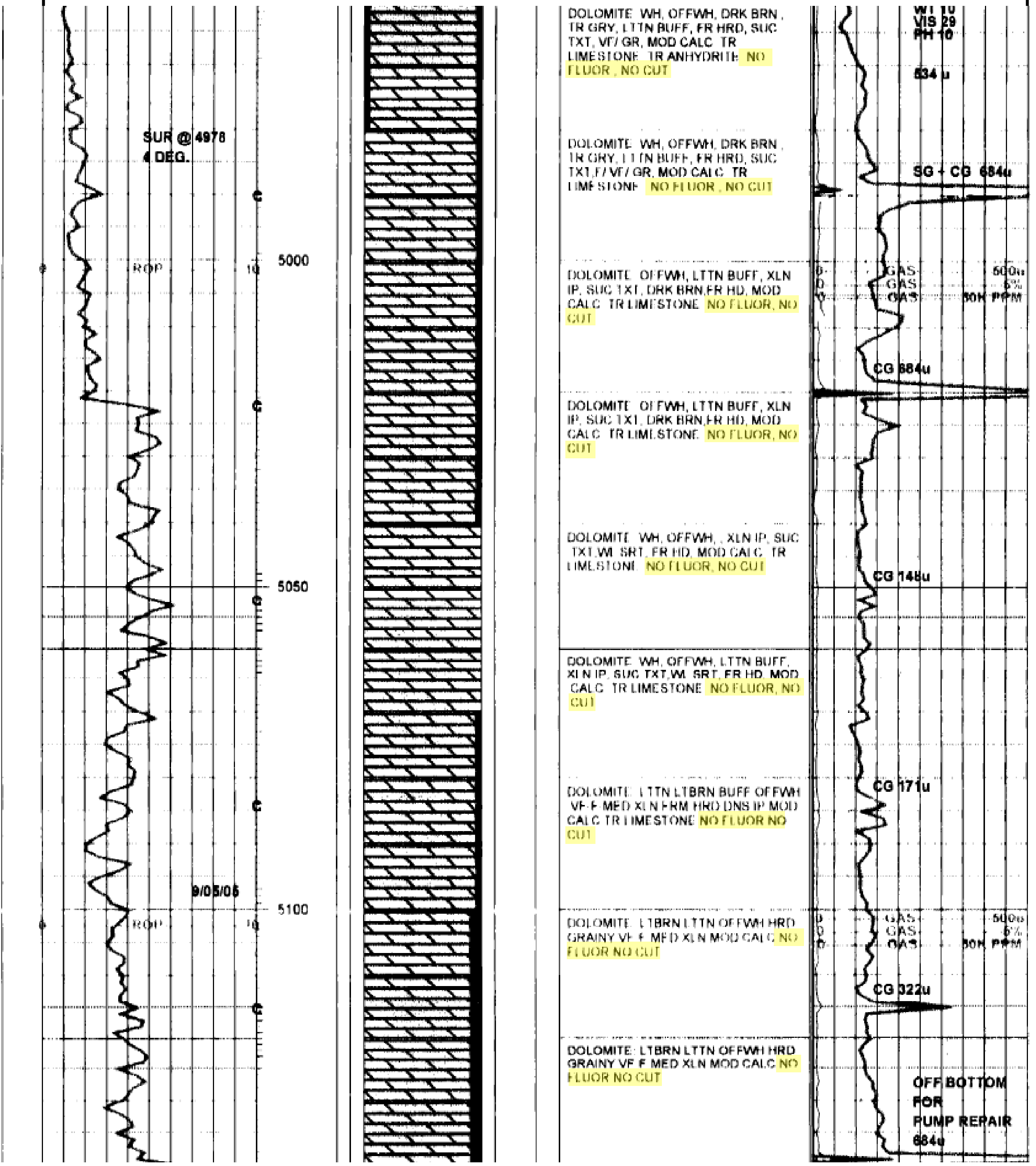
ANHYDRITE CHERT COAL
CONGLOMERATE DOLOMITE GRANITE
GRANITE WASH LIMESTONE SALT
SAND SHALE SILTSTONE

POROSITY - % CUT - FLUOR
TRACE FAIR GOOD

C 4 BUT (BROWN)
C 3 PROP (DK BLUE) C 6 CO2 (DK PURPLE)

TOTAL GAS (RED)
0-------FLARE-----200

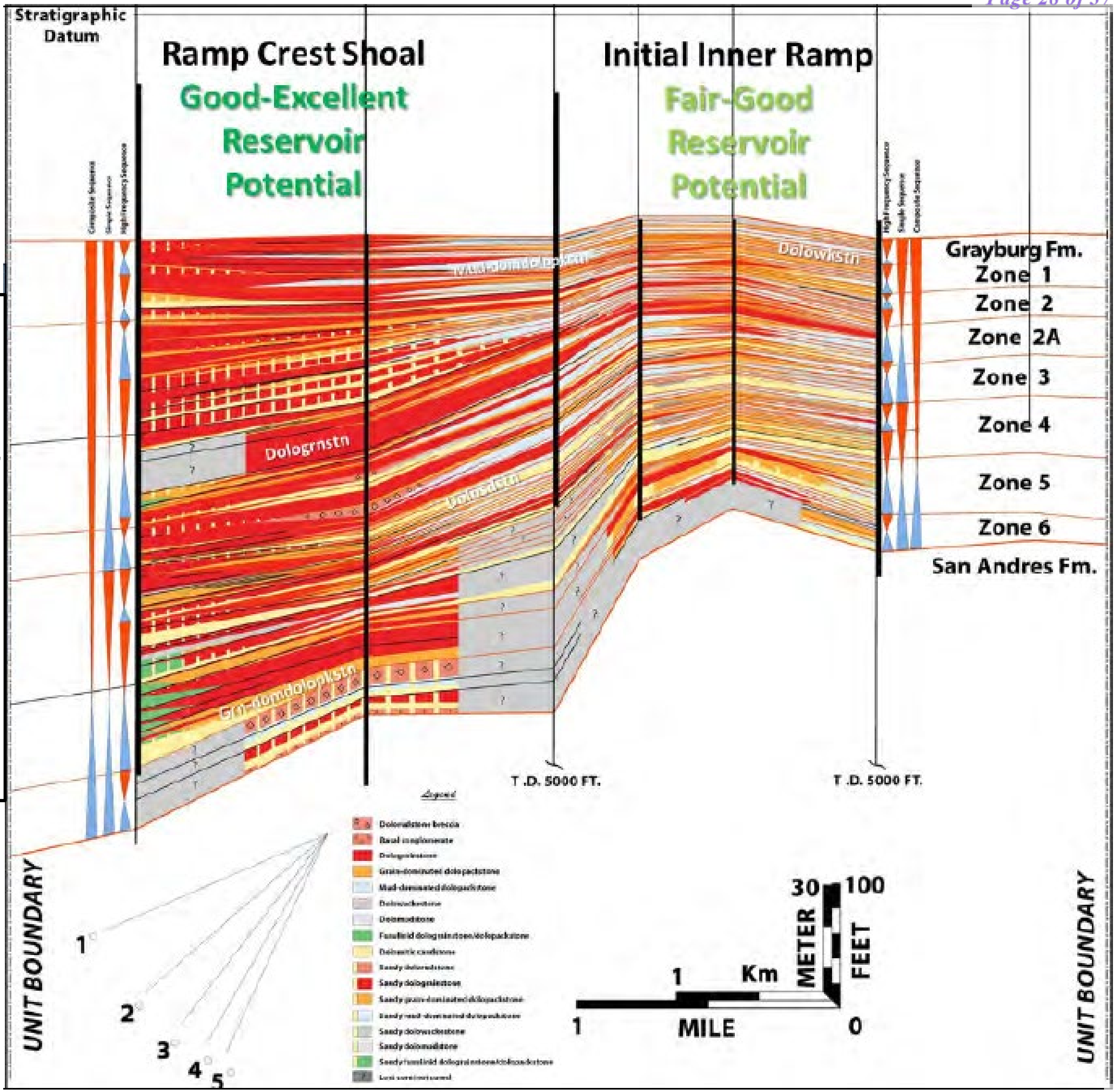
Drill Rate (min) | Wob (1000#) | DExp | DExp (corrected) | DEPTH | POR | CUTTINGS | %Cut Fluor | LITHOLOGY | GAS ANALYSIS (UNIT)

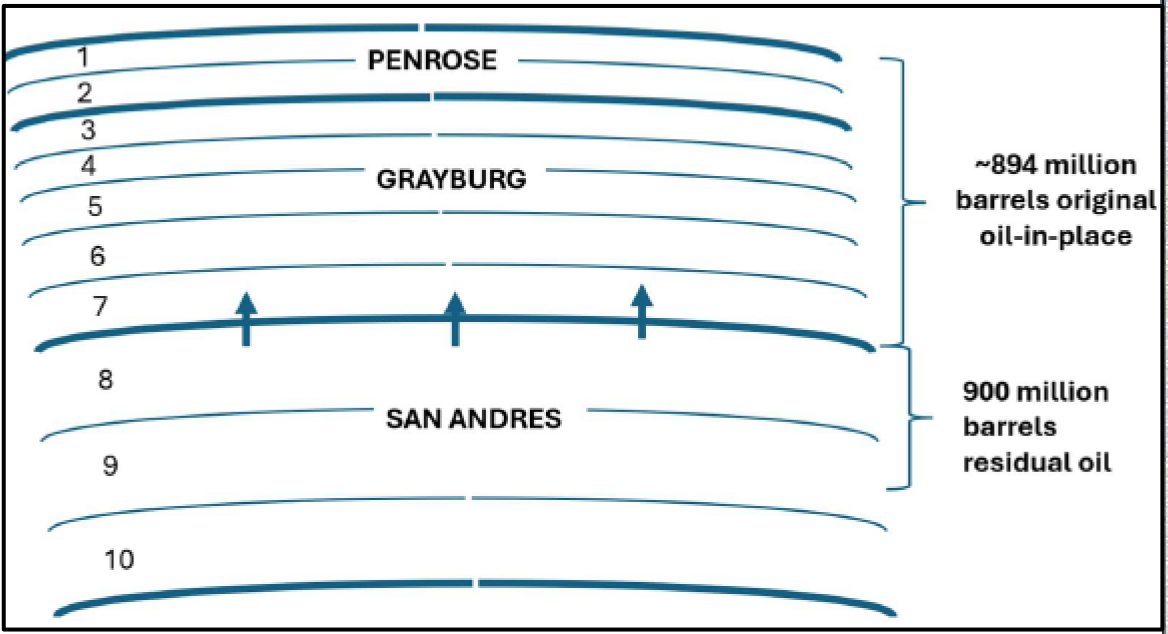


ENM OCD 23614-17: 00397

Goodnight Cross Exhibit 5

Empire B-5





Empire E-2

Goodnight Cross Exhibit 6

Dr. Buckwalter's Reservoir Model Inputs

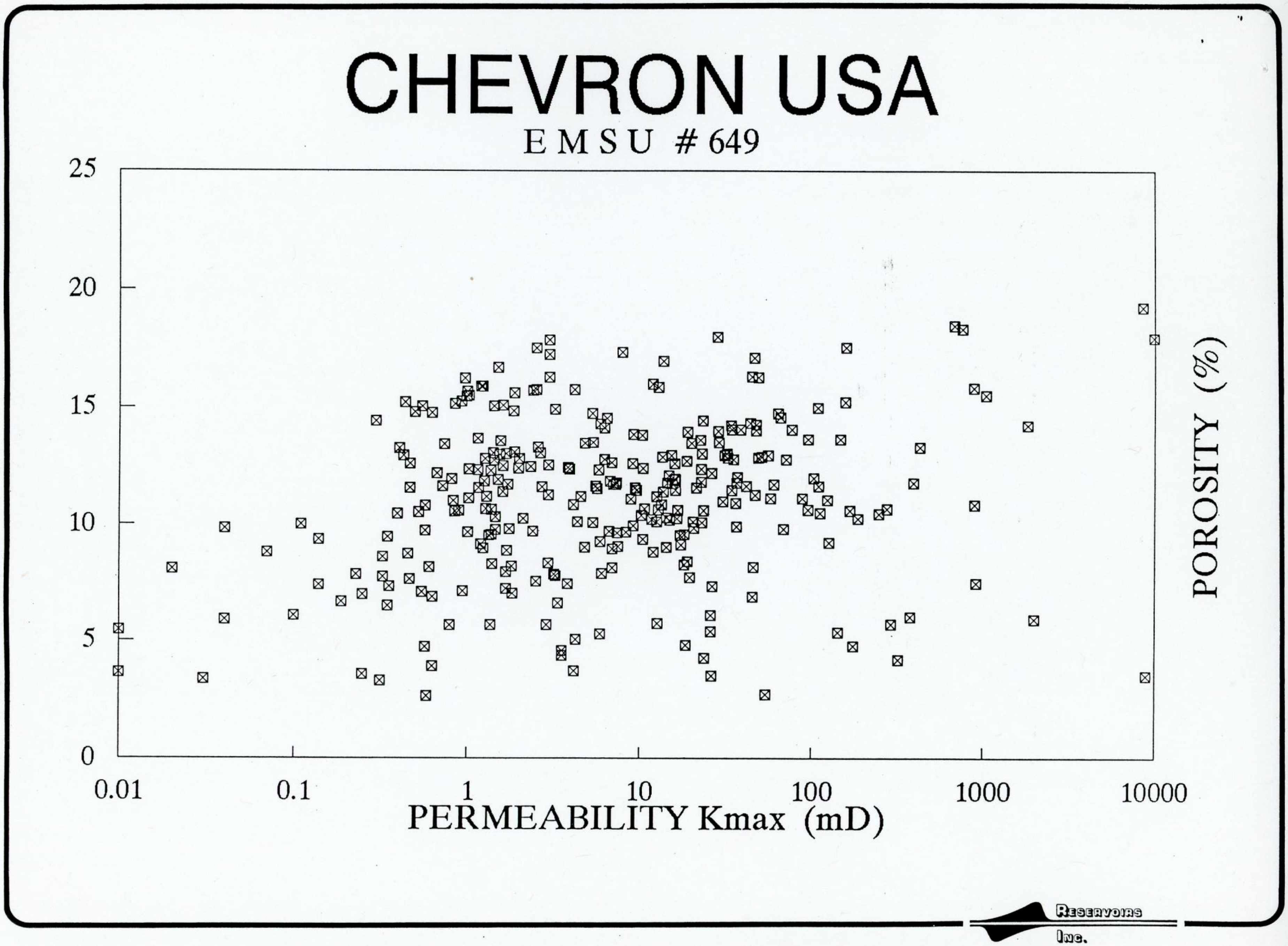
Porosity

Layer	phi description	average phi	Comments
1	constant	0.06	Penrose
2	constant	0.06	Penrose
3	variable	0.08	Grayburg
4	variable	0.08	Grayburg
5	variable	0.08	Grayburg
6	variable	0.08	Grayburg
7	variable	0.08	Grayburg
8	constant	0.064	San Andres
9	constant	0.064	San Andres
10	constant	0.064	San Andres

Permeability

Layer	KX	KY	KZ	Comments
1	100	100	1	Penrose
2	100	100	0.2	Penrose
3	500	500	1	Grayburg
4	500	500	1	Grayburg
5	100	100	1	Grayburg
6	100	100	1	Grayburg
7	100	100	1	Grayburg
8	250	250	variable	San Andres
9	250	250	1	San Andres
10	250	250	1	San Andres

Goodnight Cross Exhibit 7



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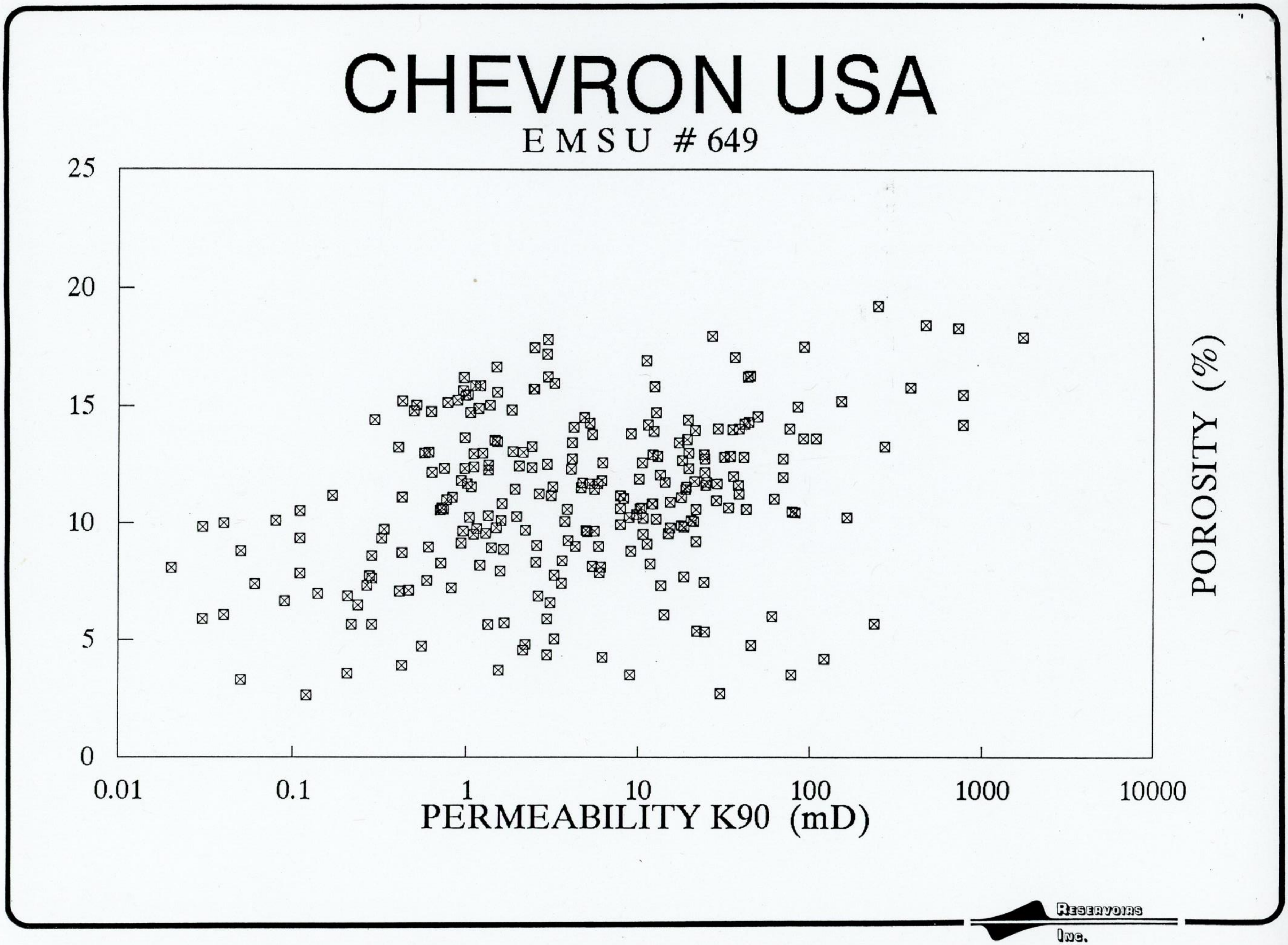
ENM OCD 23614-17: 00244


CHEVRON USA
EMSU # 649
25
20
15
10
5
0
0.01
0.1
1
10
100
1000
10000
PERMEABILITY K90 (mD)
POROSITY (%)
RESERVOIRS INC.

Goodnight Cross Exhibit 8

Exhibit M-1

JIM BUCHWALTER

GEMINI SOLUTIONS INC

JIMB@GEMINISI.COM

281-2216993

1-31-2025

EMPIRE EUNICE MONUMENT STUDY PRESENTATION

INTRODUCTION - SIMULATION

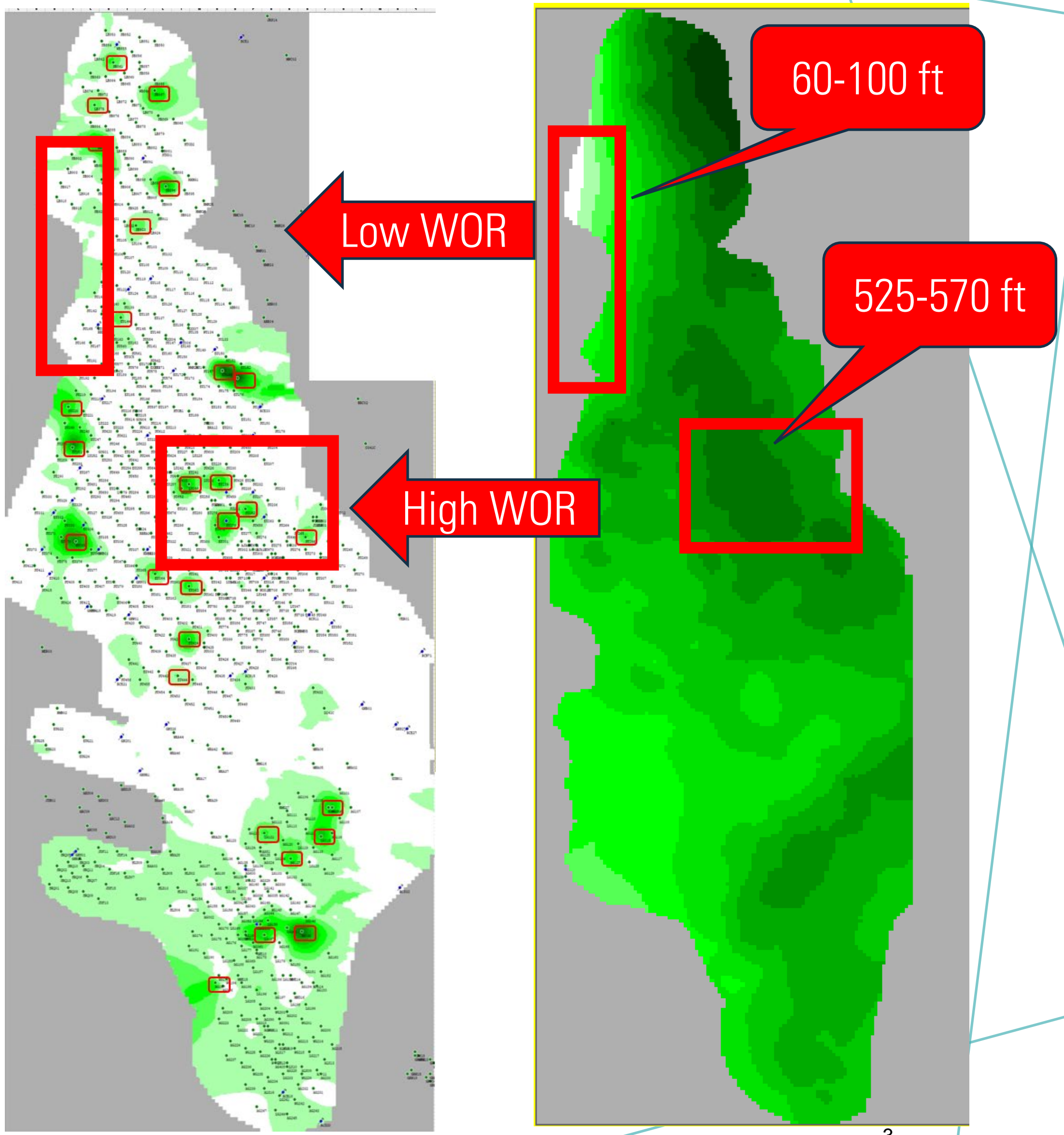
- Integrates all reservoir data pieces into one place and creates a picture
  - Production/pressure/geology/PVT/contacts, etc..
  - Ranges for data that is uncertain
    - Contacts, aquifer influx, leaks between faults and sands
- Run model and adjust parameters until a fit of recorded production and pressure is made
  - If fails client must review data and provide revised data until match attained
- Models are only accurate when enough well production data is available to establish average reservoir pressure history
  - This model has almost 90 years of production and exact estimates of volumes and leaks are established
- Matches are accomplish in steps – eat the elephant in bites
  - First establish field match to establish oil/water/gas volumes matching field rates and pressures
  - Second match production rates for group of wells
  - Third match individual wells in areas of most detail to determine infill well positions
- Models are constructed in detail sufficient to answer the question required. In this study:
  - In place volume in Grayburg and San Andres established
  - Leak rates between the two reservoirs established
  - High water-oil ratio well leaks and well groups in 3 leases modeled
  - Forecasts made

WATER PRODUCTION ANALYSIS IN 1987 BEFORE WATERFLOOD

- Maps at right show cum. WOR map in 1987 before waterflood started
- Wells with higher WOR's are not exclusively at deeper reservoir elevation compared to elevation map confirming San Andres water contribution is negligible
- Communication during primary production identified in < 6% of all wells with higher cum WOR's

Cum WOR Map

Avg Thickness from top of reservoir to oil/water contact



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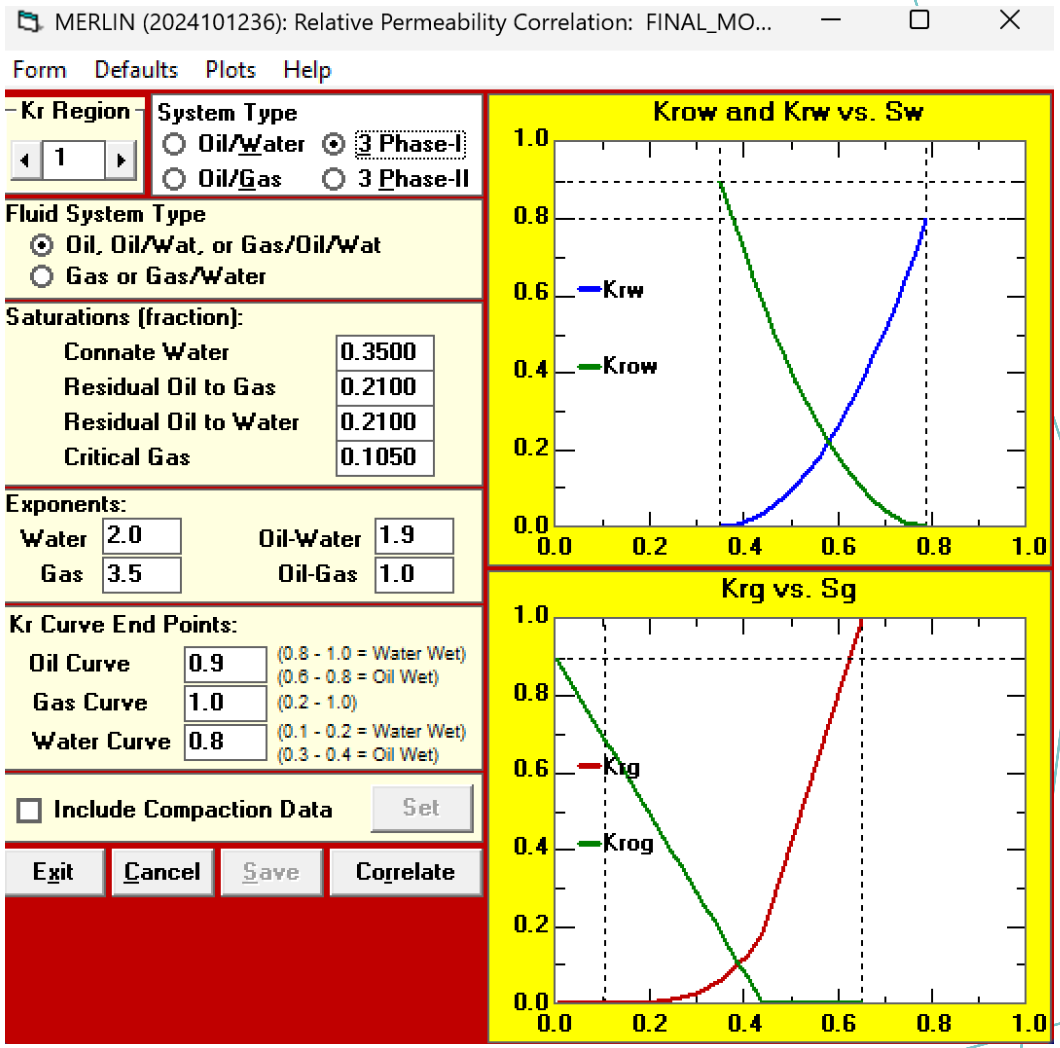
RELATIVE PERMEABILITY CURVES

FLOW THROUGH A FRACTURE NETWORK

- Production analysis
  - Primary -
    - 150 MMBO & cum WOR = 1 & 16% recovery factor
  - Waterflood- 2024
    - 185 MMBO & cum WOR & 10 & 20% recovery factor
  - Waterflood – 2038
    - 192 MMBO
- Adjustments made to fit historical gas/water production rates for oil rate wells
  - 35% water saturation
    - 35% in model
    - 30% from 1990 report
  - Residual oil saturation
    - 21% residual oil saturation in rock
    - 25% cited from1990 report
  - Linearize the Kr curves to represent flow in fracture network
  -



EUNICE MONUMENT SOUTH UNIT

EUNICE MONUMENT SOUTH UNIT EXPANSION

WORKING INTEREST OWNERS' MEETING

FEBRUARY 27, 1990

SOLUTION GOR	423 SCF/STB
CURRENT PRODUCING GOR	4007 SCF/STB
RESERVOIR TEMPERATURE	90 DEG F
OIL GRAVITY	32 DEG API
INITIAL FORMATION VOLUME FACTOR	1.20 RB/STB
CURRENT FORMATION VOLUME FACTOR	1.05 RB/STB
AVERAGE NET PAY	134 FT
AVERAGE POROSITY	8.0 %
INITIAL WATER SATURATION	30.0 %
OIL SATURATION AT START OF WATERFLOOD	50.0 %
RESIDUAL OIL SATURATION	25.0 %

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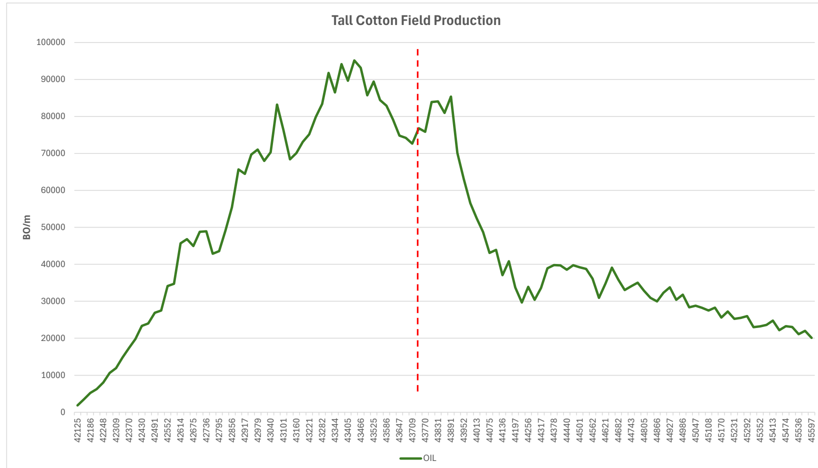
Goodnight Cross Exhibit 9

Date	OIL	GAS	WATER
5/1/2015	1,860	-	128,028
6/1/2015	3,508	-	241,464
7/1/2015	5,226	-	359,718
8/1/2015	6,276	-	431,992
9/1/2015	8,016	-	551,761
10/1/2015	10,625	-	731,344
11/1/2015	11,929	-	821,102
12/1/2015	14,778	11,844	1,017,205
1/1/2016	17,373	14,874	156,775
2/1/2016	19,800	17,025	178,676
3/1/2016	23,353	20,206	210,739
4/1/2016	23,999	20,037	216,568
5/1/2016	26,887	21,183	242,630
6/1/2016	27,513	24,841	248,279
7/1/2016	34,130	29,395	307,991
8/1/2016	34,720	30,171	313,315
9/1/2016	45,693	41,916	412,336
10/1/2016	46,819	36,455	422,497
11/1/2016	44,934	38,638	405,487
12/1/2016	48,777	36,862	440,166
1/1/2017	48,945	37,707	435,995
2/1/2017	42,886	36,987	382,022
3/1/2017	43,565	37,733	388,071
4/1/2017	49,193	38,743	438,204
5/1/2017	55,412	40,230	493,602
6/1/2017	65,687	53,302	585,130
7/1/2017	64,481	61,589	574,388
8/1/2017	69,698	76,231	620,860
9/1/2017	71,056	71,722	632,957
10/1/2017	67,952	68,723	605,307
11/1/2017	70,325	90,259	626,445
12/1/2017	83,203	103,854	741,160
1/1/2018	76,302	79,492	336,968
2/1/2018	68,389	73,230	302,022
3/1/2018	70,094	81,482	309,552
4/1/2018	73,105	78,955	322,849
5/1/2018	75,131	81,478	331,796
6/1/2018	79,826	94,820	352,531
7/1/2018	83,360	111,732	368,138
8/1/2018	91,780	122,486	405,322
9/1/2018	86,497	113,397	381,991
10/1/2018	94,169	115,674	415,873
11/1/2018	89,626	113,579	395,810
12/1/2018	95,169	119,372	420,289
1/1/2019	93,171	126,687	317,600
2/1/2019	85,725	114,518	292,218
3/1/2019	89,427	141,107	304,837
4/1/2019	84,422	140,020	287,776
5/1/2019	82,900	129,844	282,588
6/1/2019	79,146	133,396	269,791
7/1/2019	74,823	127,399	255,055
8/1/2019	74,194	127,120	252,911
9/1/2019	72,640	120,071	247,614
10/1/2019	76,802	118,817	261,801
11/1/2019	75,827	118,265	258,478
12/1/2019	83,895	131,940	285,980
1/1/2020	84,068	124,201	511,230
2/1/2020	80,956	127,950	492,306
3/1/2020	85,381	121,994	519,215
4/1/2020	70,135	110,514	426,501
5/1/2020	63,063	99,061	383,496
6/1/2020	56,553	88,995	343,907
7/1/2020	52,441	78,878	318,902
8/1/2020	48,697	80,273	296,134
9/1/2020	43,071	83,175	261,921
10/1/2020	43,897	78,652	266,944
11/1/2020	37,080	64,976	225,489
12/1/2020	40,825	69,222	248,263
1/1/2021	33,750	59,203	347,133
2/1/2021	29,685	47,771	305,322
3/1/2021	33,917	62,514	348,850
4/1/2021	30,408	57,442	312,759
5/1/2021	33,615	61,792	345,744
6/1/2021	38,926	64,801	400,370
7/1/2021	39,817	63,935	409,534
8/1/2021	39,702	68,212	408,351
9/1/2021	38,533	66,477	396,328
10/1/2021	39,770	70,933	409,051
11/1/2021	39,203	56,952	403,219
12/1/2021	38,757	52,360	398,632
1/1/2022	36,121	60,579	257,713
2/1/2022	30,903	57,706	220,484
3/1/2022	34,831	56,514	248,509
4/1/2022	39,095	63,328	278,932
5/1/2022	35,865	59,568	255,886
6/1/2022	33,038	57,317	235,717
7/1/2022	34,074	61,574	243,108
8/1/2022	35,020	64,572	249,858
9/1/2022	32,814	61,045	234,118
10/1/2022	30,935	59,211	220,712
11/1/2022	29,964	61,389	213,784
12/1/2022	32,323	78,359	230,615
1/1/2023	33,795	86,415	362,627
2/1/2023	30,393	60,088	326,123
3/1/2023	31,804	80,415	341,263
4/1/2023	28,367	63,742	304,384
5/1/2023	28,815	79,432	309,191
6/1/2023	28,260	77,077	303,236
7/1/2023	27,506	66,877	295,145
8/1/2023	28,267	62,580	303,311
9/1/2023	25,590	59,396	274,586
10/1/2023	27,233	59,737	292,216
11/1/2023	25,240	65,767	270,830
12/1/2023	25,525	65,859	273,888
1/1/2024	25,998	60,523	314,915
2/1/2024	23,003	55,181	278,636
3/1/2024	23,237	57,937	281,471
4/1/2024	23,599	58,349	285,855
5/1/2024	24,797	56,823	300,367
6/1/2024	22,185	54,462	268,728



7/1/2024	23,267	55,680	281,834
8/1/2024	23,039	56,670	279,072
9/1/2024	21,087	55,565	255,428
10/1/2024	22,030	56,481	266,850
11/1/2024	20,121	55,208	243,726