UTILIZATION OF A CRYSTALLIZED HYDRATING COPOLYMER TO MODIFY AN INJECTIVITY PROBLEM IN A HORIZONTAL CO_2 WAG INJECTOR IN THE SOUTH COWDEN UNIT, ECTOR COUNTY, TEXAS – POST TREATMENT COIL TUBING ACIDIZING STIMULATION - CASE HISTORY

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ABSTRACT

An open-hole completed lateral CO_2 WAG injection well in the San Andres formation had not performed as desired in developing a sweep of upper structure pay and indications were that an injection profile problem existed. It was ascertained that all injection fluids were entering into a known 30–40 ft. interval approximately 230 ft from the toe of this 1,337-ft horizontal lateral rendering the remaining lateral section ineffective. Tracer surveys and interference pressure tests showed most injection fluids were being lost out of the productive interval and not giving the desired response to offset producers.

A conformance design utilizing a dehydrated crystallized copolymer was implemented to control the loss of injection fluids into the unwanted zone. With confirmation of a positive treatment response, a coil tubing stimulation utilizing 135°F heated acid was performed to improve injectivity into the desired intervals within the remaining lateral section.

INTRODUCTION

The well described in this paper was part of an ongoing DOE project to economically design an optimum carbon dioxide (CO_2) flood for a mature waterflood nearing its economic abandonment. [Figure 1] The original project used advanced reservoir characterization and CO_2 horizontal injection wells as the primary methods to redevelop the unit. [Ref 1, 5, 6] Well 7C-11H was drilled approximately normal to the preferential parting direction. The trajectory of the well was 1,337 ft (Azimuth: 65° West of True North). The well was designed mechanically to optimize well injection performance and maximize duration of their utility due to the required CO_2 service. Well 7C-11H was equipped with 9-518 in. 36 lb/ft J-55 surface casing and 7 in. 20 lblft J-55 production casing through the curve. An injection packerltubinglwellhead designed for CO_2 service was used. [Table 1] The well was initially stimulated with 15% HCl acid by coiled tubing acid washing sweeps.

This openhole completed lateral CO_2 WAG injection well in the San Andres formation had not performed as desired in developing a sweep of upper structure pay and indications were that an injection profile problem existed. It was ascertained that all injection fluids were entering into a known 3040 ft interval approximately 230 ft from the toe of this 1,337 ft horizontal lateral, rendering the remaining lateral section ineffective. Tracer surveys and interference pressure tests gave indications that most injection fluids were being lost out of the productive interval and not giving the desired response to offset producers. [Table 2] The operator needed to seal this dynamic loss interval in order to stimulate and gain entry into the remaining lateral section to achieve the desired sweep efficiency.

Based on injectivity log profiles and formation reservoir characterization studies, a conformance design using a dehydrated crystallized copolymer (a proprietary drilling loss circulation material consisting of dehydrated copolymer crystals) was implemented to control the loss of injection fluids into the unwanted zone. A volume of 2,500 gals of produced water was used to place 600 lbs of varying concentrations of the dehydrated crystallized copolymer into the determined thief zone. With confirmation of a positive conformance treatment response, coil tubing and a hydraulic blasting tool were used to stimulate with 12,600 gals of 15% HCl iron controlled acid to improve injectivity into the desired intervals within the remaining lateral section. Based on laboratory testing on formation cores samples, the acid was heated to 135°F to optimize reactivity. Results of laboratory analysis addressing reactions on core intervals with various temperatures of HCl were determined. [Table 3]

HORIZONTAL INJECTOR IN A SAN ANDRES FORMATION FOR EVALUATION

The unit produces primarily from the Grayburg and San Andres formations of Permian Age. These formations were deposited in shallow shelf carbonate environments along the eastern margin of the Central Basin in West Texas.

The purpose of the DOE project was to economically design an optimum carbon dioxide (CO_2) flood for a mature waterflood nearing its economic abandonment. The unit was a mature waterflood with water cut exceeding 95%. Oil must be mobilized through the use of a miscible or near-miscible fluid to recover significant additional reserves. Two primary methods were used to accomplish improved economics. Reservoir characterization to restrict the flood to the higher quality rock in the unit and use of horizontal injection wells to cut investment and operating costs. The innovative approach involved CO_2 flooding of the unit through multiple horizontal injection wells from a centralized location. [Refs 1, 2, 3, 4, 5, 6]

The primary target for CO_2 flood development for the project was a 150-200 ft gross interval within the Upper San Andres located at an average depth of approximately 4,550 ft. The original oil in place (OOIP) for the unit is estimated to be 180 million barrels. The field was discovered in 1940 and unitized for secondary recovery operations beginning in 1965.

The unit was nearing its economic limit in 1995, producing 342 barrels of oil per day (BOPD) at a water-cut in excess of 95% from 42 active producers and 15 active water injectors.

The drilling and completion operation for horizontal CO_2 injector Well 7C-11H (northwest well) began April 14, 1996 and was completed in 20 days. [Fig 2]

HISTORICAL EVALUATIONS, PERFORMANCE, AND EVENTS

Prior to injection startup, Well 7C-11H was acid washed with coiled tubing. The original procedure recommended maximum surface pressures of 5,000 psig while acidizing the well. It was discovered during the operation that the well was not open to controlled flow returns. No records of the actual treating pressures have been found; therefore it is difficult to determine whether the acid wash caused fracturing at the toe of the well. The end section of well 7C-11H would have the least skin damage and hence be more prone to fracturing.

A postulated fracture within Well 7C-11H may be combinations of original small fracture planes which when acid stimulated at high pressure, was opened wider. It was not clear where the CO_2 entering the toe at Well 7C-11H was disappearing. If it was a fracture system, it could be connected to any of the San Andres intervals and the majority of CO_2 injection may be wasted. The size of the fracture system was unknown, as was its orientation.

Core data from Well 7-10 (adjacent to Well 7C-11H's "toe") revealed that E zone permeability varies between 1 and 10 millidarcies (mD). The D zone typically has 0.1 to 1 mD, C zone between 0.8 and 8 mD, B zone 0.1 to 2 mD, and A zone ranging between 3 to 250 mD. This would suggest the eventual destination for CO_2 would preferentially be the **A** zone (lowest structurally) if the fracture communicates into all layers.

If it had a high permeability streak or small fracture in the E zone it may have been injecting in zone, but the areal distribution benefits of the horizontal well were not being exploited.

Horizontal injection Well 7C-11H was determined to have the majority of CO_2 entering the toe of the well. Methods discussed to isolate this well section included packers, crosslinked polymers, cement, foamed cement, in-situ polymerizing monomers, and sodium silicates. These methods had been reviewed in detail with the operator and service companies, but no ideal solution for isolation had been realized up to end of 1999, either because of risk or expense. Also, the best producing oilwell, offset Well 7-01, had indicated CO_2 response from the toe of Well 7C-11H, and it was deemed too risky and expensive at that time to risk losing this oil productivity.

A third explanation of early breakthrough was that the CO_2 originated from out of zone injection at the toe of the horizontal CO_2 injection Well 7C11H. Core data from the nearby 7-10 well suggest the lower layers of the San Andres have high permeability streaks compared to the upper layers. This correlation is repeated in offset wells that have core data down to the lower San Andres interval. The toe injection at Well 7C-11H could therefore be entering the lower San Andres formation and communicating to wells such as 6-22 in the southern part of the lease through the high permeability layers in the lower San Andres.

INJECTION TESTING WHILE UNDER CO_2 INJECTION

An injection profile survey was performed during initial CO_2 injection. This injection profile survey was to evaluate CO_2

injection performance and determine lateral/vertical distribution of injected fluids. In contrast, Well 7C-11H injection and shut-in temperature passes indicated possible fluid loss out the toe of the horizontal section. This interpretation was based on only a 0.25°F temperature change at the toe of the horizontal section. This minor change in temperature could also have been caused by a rising water level in the horizontal wellbore. The capacitance log indicated a CO_2/water interface at approximately 6,210 to 6,200 ft WL while the well was on injection. The 1-hr shut-in pass showed the interface had moved to approximately 6,140 ft WL. The 2-hr shut-in pass indicated water throughout the entire openhole section. It is important to note that the tools were not centralized; therefore, these readings did not necessarily prove that the wellbore was full of water. They merely indicated the presence of some water in all the openhole section during the shut-in periods. A fracture had been suspected during the falloff and step rate testing, and was further suggested by this profile log under CO, injection

A third injection profile was run during October 1997 to confirm identified losses in the toe of the well. Gamma ray and temperature logs confirmed major loss in two distinct intervals in the well's toe, at 6,100 to 6,110 ft MD and 6,150 to 6,180 ft MD. The log also indicated a possible internal diameter (ID) restriction at 5,400 ft MD. The well was placed back on CO, injection following this survey. The information obtained from the injection profile logs was used for designing mobility control measures to prevent out of zone injection through the toe region of Well 7C-11H. [Fig 3, Ref 9]

PRESSURE ANALY

Several analyses were performed based on measurements and noted were changes in both injectivity and the appearance of a defined fracture loss in the well. The analysis proved extremely useful for understanding the characteristics of this well. The test on Well 7C-11H had revealed that the fracture present at the well's toe was confirmed as a pressure-induced fracture that currently appears to be getting easier to inject into compared to CO, startup in 1995.

The fracture dimensions at Well 7C-11H are dependent on the thickness used for analysis, but could be estimated as:

Xf (half length) = 32 ft, using an infinite conductivity model and 280 ft thickness.
Xf (half length) = 70 ft, using an infinite conductivity model and 60 ft thickness.
The closure pressure is estimated at 1,988 pounds per square inch gauged (psig).

These results were used for potential volumes required for conformance work. Also noted from the analysis, was the fact that the fracture was induced above a certain pressure. This characteristic was observed both in 1996 and 2000 tests. This suggested that a pre-existing fracture system did not exist at the toe and was only induced to form above a certain pressure. [Ref 7]

FRACTURE STUDIES

Studies were conducted on the evaluated potential fracture growth geometries resulting from water injection into the San Andres formation in this unit. The formation consists of a sequence of dolomites, anhydrites, and sands at a depth of about 4,500 to 4,800 ft. The main objective of these studies was to determine whether fractures grow downward from the principal pay zones (San Andres C, D, E, F and G) into the water-bearing higher permeability A and B zones. Based on openhole injection test data, the operator suspected that downward fracture growth may be occurring due to increased stresses in the pay zones. The study was performed using a 3-D hydraulic fracture model and data from stress logs, mini-frac injection tests, pore pressure estimates, and core studies. Information from this study was used to help identify the nature of the inefficiency on the horizontal injector Well 7C-11H. Details of the fracture analysis were based onvariances in rock stresses and historical pore pressure changes. [Ref 8]

Stress logs seemed to indicate that the E section was the zone with the highest rock stress (0.61 psi/ft). Stresses are lower both above (F and G sections) and below (A, B, and D sections). Stresses in the C zone are close to the ones in the E zone. Modeling the effect of pore pressure changes on rock stresses indicated that the E section had very low stress (0.46 psi/ft) at the beginning of the waterflood (1970–1980) and increased over time as the waterflood increased pore pressure. Due to uncertainties associated with rock stresses obtained from stress logs, it was necessary to calibrate those measurements with actual injection data and apply appropriate corrections.

FRACTURE MODELING RESULTS

The objective of the study was to determine whether fractures could potentially grow down into the water-bearing A and B intervals. After initial scoping simulations in which analysis used different parameters, such as fluid leakoff, stress profile, perforated interval (location of fracture initiation), and injection rate, results indicated the location of fracture initiation, injection rate, and stress profile had the biggest impacts on the potential for downward fracture growth.

Estimating Fracture Capacity: using 35 ft fracture half length
70 ft singular fracture if downward (E zone to A zone)

Estimated width 0.15 to 0.1 inch Ave = 0.125 in.
Estimated height (note: non-planar to the horizontal well) = 21.88 ft
Volume = 21.28 ft^3 163 gals

ADDRESSING THE METHOD OF GAINING ENTRY INTO THE FORMATION FOR SQUEEZE PLACEMENT

The possibility of addressing the best method for establishing squeezing out from the loss section at the lower part of the lateral and determining whether there is a direct channel to offset wells was critical. If it was possible to open this portion up to injection and determine if that it would change the pressure (shut-in) on this offending injection source well, it would give the operator insight as to what method and what type of material would be best suited to attempt this squeeze. It was also necessary to determine that injection at a suitable rate could place enough material into this fracture channel with connections to possible high permeability streaks to solve the problem of losses of injectant.

SOLUTIONS EVALUATED

It is best to develop a solution based on indications from a well's response and ability to gain entry into a formation in a manner that will be sufficient to achieve a successful placement. Without this information, recommendations for solution materials and methods of placement must be addressed. By taking the steps necessary to develop a proper solution, the operator would only spend the required moneys necessary to investigate the ability to achieve success prior to doing any spending on an actual job solution.

The material best suited for injecting into this loss interval needed high viscosity, the ability *to* withstand influxes of water and gas, and the ability to give a final high compressive strength or a high resistance to extrusion. Ideally, foamed cement would be best if tests indicated that a suitable injection could be done. **A** sufficient injection rate was needed to prevent deterioration per influx of water and feasible fracture entry.

A silicate gel solution could be used, but due to the high salt content, it would be very rapidly accelerated into a set solution due to an external reaction. If it could not be placed to a sufficient distance from the horizontal lateral, it would not be effective and might cause premature pressure restrictions and curtail the placement.

Due to a history of addressing major problems in the unit with out-of-zone injection (water and CO,) the tested and preferred method of the operator is foamed cement. Typically, the inability to open up intervals for production and/or injection has resulted in re-entry via fractured communication back down into the aquifer. In initial workovers, the wells that were foam cement squeezed were broken down with conventional spotting of acid across the upper intervals and using above parting pressure. **A** modification to the foam-cement squeeze process to build resistance to this pressure problem was successful in stopping out-of-zone re-fracturing. The solution technique selected might also require coil tubing for spotting, washing across intervals, and re-spotting new acid for effectiveness.

The operator brought out core samples from Houston for a qualified acid solubility analysis. The acid type, temperature, etc. was evaluated to address the rock's solubility and reaction time. Once this information was garnered, a recommendation was built based on the analysis.

Horizontal Well 7C-11H had procedures written and evaluated for the best placement method using (1) a dehydrated crystallized copolymer, or (2) a foam cement squeeze to stop the out-of-zone injection problem. Decisions were addressed to either squeeze with current tubular configuration or to pull the 3 1/2 in. injection tubing and run in with a liner for the openhole horizontal completion. If a liner was run, it would be foam cemented with considerations of the fracture out-of-zone entry. The liner option would give future control on injection via perforations as a benefit.

Based on ongoing testing for performance and economic reasons, the dehydrated crystallized copolymer was chosen for the first attempt to stop out of zone losses. If this attempt failed, a foam-cement squeeze would be attempted.

DISCUSSION ON SOLUTION TREATMENT PARAMETERS

The 3 ½ in. tubing would be used to inject the crystallized copolymers into the loss zone at 6,060 to 6,130 ft MD. The nature of the crystallized copolymers would allow injection down the current injection tubing and packer, enabling placement into the fracture system without having to perform a workover involving pulling the tubing and assembly.

Injectivity analysis for entries from the lateral horizontal section showed that the continuance of injection had remained in this interval over the past year (mid-1999 to mid-2000). Injection of over 2,000 psi led to the total fluid entering the fracture system. Only a nominal amount of leak-off into the rock permeability existed at this pressure. Injectivity pressure as high as 2,600 psi showed a major portion of the injectant entry still within the fracture system.

The solution, a dehydrated crystallized form of copolymer (crosslinked copolymers), will hydrate following exposure to aquatic-based fluids. The time in which the crystallized copolymers will start to hydrate is over 20 min if in fresh water and at temperatures less than 100°F. Utilization of produced brines (8.9–9.2ppg) will have a delay of around 45 min prior to the crystals hydrating.

The volume required may be determined from injectivity analysis or the understanding of the fracture system's estimated width and half-lengths. Once placed into the injectants stream (normal injection water), the well may be closed in for a period of 3 to 6 hrs to allow the crystallized copolymers to thoroughly hydrate and swell. The material will swell from 100 to 400 times its crystal volume in fresh water and 50 to 100 times its crystal volume in produced water. The well can then be placed back on injection and analyzed for profile if desired or evaluated from pressure responses. If desired, a follow-up stimulation process can be performed to remove damage from other portions of the wellbore. The crystallized copolymer has been researched and noted as having resistance to acid, bacteria growth, and CO_2 degradation. The crystallized copolymers, like all copolymers, may be removed on contact with oxidizers or bleach solutions whereby its backbone is broken and it becomes water-like.

Past entry at the interval of 6,060-6,130 ft MD, was indicated to be entering and going down through fractures into the lower San Andres. The injection rate needed to place the crystallized copolymers into the fractures and be displaced from the wellbore would be dependent on the volume injected and the placement rate.

DISCUSSION ON PLACEMENT PARAMETERS

Desire was to displace the crystallized copolymers with viscous gel water to the MD of 6,060 ft. If there existed a pressure build-up to the maximum allowed staying below fracturing, the injection would be stopped and the well closed in. Excess crystallized copolymers would be cleaned out with a coil tubing unit post-treatment.

The dehydrated crystallized copolymer is designed to enter fractures and is physically unable to enter any formation rock permeability. As a result, it can be easily pumped at surface until the fracture is filled. Any surplus dehydrated crystallized copolymer can be washed out of the horizontal section, and if required, the dehydrated crystallized copolymer can be reapplied in steps until the fracture is sealed.

A displacement of 78 bbls of gel water was needed to displace the crystallized copolymers to 6,060 ft MD. Injection was to be performed at ± 3 barrels per minute (BPM) liquid rate to ensure placement prior to hydration of the copolymer. Contact time of the crystallized copolymers to the mix water was estimated at 46 min on the leading portion and 30 min on the tail-in portion. The concentration of the crystallized copolymers would be stepped up to gain a higher potential for blockage on the tail-in portion of the treatment. If the treatment was under displaced, determining the placement of the crystallized copolymers with the amount left in the tubing or openhole would be calculated.

PRELIMINARY TREATMENT DESIGN

The service provider developed a procedure involving the use of their proprietary dehydrated crystallized copolymer product, which would be injected at surface, enter and seal the fracture system, and then be washed out with coil tubing if needed. A workover was performed in July 2001 to reduce the injection losses in the toe of the well.

VOLUME OF CRYSTALLIZED COPOLYMER

Volume was based on the ability to place non-hydrated crystals into the fracture system.

The well treated as predicted with a noted pressure build at the final state of placement. The well was shut in for a minimum of 3 hrs to allow the crystallized copolymers to fully hydrate and gain resistance to extrusion. A follow-up coil tubing acid wash to remove possible damage in the remaining wellbore was setup for the following day.

ACID STIMULATION AND SOLUBILITY AND REACTION TESTING

Historically, acid stimulations performed above fracture pressure indicated on mini-fracturing tests developed communication to the majority of intervals in the San Andres, even if perforations were contained within the upper layers. Core permeabilities from various wells had highlighted the fact that lower San Andre's intervals have better permeability than upper layers in the majority of the field. An acid stimulation, in which treatment pressure exceeded fracture initiation pressure would therefore open up communication paths to higher permeability, lower San Andre's intervals and preferentially inject acid into the high permeability lower layers.

Core samples from 6-24 (offset well), from various zones in its San Andres, were tested for acid solubility and reaction time at various temperatures. These tests revealed that carbonate intervals with high-anhydrite content, or intervals with high-clastic content (lower permeability in upper layers) tended to have slow reaction times when compared to low-anhydrite carbonates (high permeability in lower layers). For example, upper layers in the E zone (high-anhydrite content) and the interval between the C and D zones (high-clastic content) had lower reaction time compared to the low-anhydrite content C zone. Sensitivities to acid treatment temperature revealed that reaction times for high-anhydrite content intervals could be improved by raising treatment temperature, whereas, low-anhydrite or high-clastic content interval's reaction time was not affected by treatment temperature. [Table 2]

For example, the lower layer C zone had measured core permeability of 831 mD with slight anhydrite content. Over a 15-min period, dissolved in 15% hydrochloric acid (HCl), the sample lost 95% of its original weight. The target E zone had a permeability of 6 mD at 4,697 ft and lost 54% of its original weight. Higher up in the E zone at 4,678 ft, permeability was 1.4mD and the sample lost only 26% of its original weight. In the G zone where anhydrite content is high, permeability was 0.01 mD and the sample barely reacted with the acid, losing only 7.6% of it original weight. Also noted was the fact that the barrier between the C and D zone, a dolomitic sandstone, is one of the really extensive permeability barriers preventing vertical communication to lower zones, had very poor reaction to acid. [Table 3, Ref 7]

The results of these lab tests were important for an understanding of controlling vertical fracture growth. Any acid stimulation performed above fracture pressure, that will allow communication to low-anhydrite content intervals, will preferentially react with those low-anhydrite intervals. Therefore, any acid stimulation performed on an interval perforated in the target E zone, which had to be performed above fracture pressure, would allow open communication to lower intervals. Most noticeably, this would be in the high permeability (low-anhydrite) grainstone interval, which is normally below the oil/water contact. To improve acid reaction times and solubility of the rock where there was a higher anhydrite content, it was heated at surface.

COIL TUBING HEATED-ACID CLEAN/OUT

A post treatment cleanup of the remaining openhole portion from the casing shoe to the depth of 6,060 ft was performed using a coil tubing unit with a hydraulic blasting tool and heated 15% iron control HCl acid. The hydraulic blasting tip was used to remove excessive damage, such as scale and paraffin in the open hole.

Service company field operations teamed with the operator's field personnel to set up two lined frac tanks for the job, noting the frac tank supplier's fluid temperature limitation for their frac tanks. One tank was set up for the slick wash and another for the heated acid. These tanks were cleaned to reduce the amount of particles in them. Arrangements were also made to set up a hot oiler to heat the water to 160°F. A 28% HCl acid would be added to the heated water for a resultant 135°F 15% HCl acid.

TREATMENT PROCEDURE

Operations ran in coil tubing with a spiral hydraulic blasting tip to the end of the well's injection tubing. The use of centralizers on the coil tubing was prohibited due to the profile nipples' clearances within the well's tubulars. Operations began injection with a treated slick 2% potassium chloride (KCl) solution. Treatment was monitored via the tubing/coil tubing annulus and allowed to flow to the pit through controlled backpressure chokes.

Operations then began injecting (inserting) the coil tubing into the horizontal well while maintaining fluid injection. Once at the MD of 6,000 ft, they began pumping a 135°F heated acid to treat and remove damage from the horizontal from 6,000 ft back to a MD of 4,800 ft (128 ft out from the casing shoe). Design was to inject ¼ bbl acid per ft of hole. The pull travel on the coil tubing matched the injection rate of acid so that 10 gals acid was injected for every ft pulled. A 1-BPM rate was maintained, the coil tubing pull rate was 4 ft per min, and pressure differential across the hydraulic blasting tool was ±2,500 psi. Returns from the tubing/coil tubing annulus were controlled to stay below a pressure of 600 psi. If a higher rate could have been achieved, the pull rate on the coil tubing would have been adjusted.

Once the coil tubing covered the desired treatment interval, the volume of 12,600 gals of heated 15% iron control acid was injected. Operations switched to treated slick 2% KCl water and washed back to 6,000 ft MD. They continued injecting the treated slick 2% KCl and washed back out of the horizontal.

After the coil tubing was pulled from the well, the well was placed on water injection with a return to CO, injection following pressure and rate analysis.

ACID TREATMENT AND COIL TUBING PERFORMANCE

The heated acid treatment was performed at Well 7C-11H and proved operationally successful. The configuration at surface was to heat the water to 160°F and commingle with 28% hydrochloric (HCl) acid at surface conditions. This would dilute the mixture being placed down the injection stream to 15% HCl acid at a temperature of approximately 135°F at surface. The coiled tubing hydraulic blasting tool was moved throughout the lateral section with no problems.

POST TREATMENT RESULTS

Post-treatment injectivity pressure response indicated the dehydrated crystallized copolymer conformance treatment successfully sealed off the unwanted injection zone. The follow-up stimulation was successfully executed.

Prior to treatment, it is estimated that 80% of the initial 3,000 mcfd CO, injection was being lost into nonproductive zones or communicating directly with a nearby producer. Improved withdrawal rates of 48% from surrounding producing wells following the treatment also suggest that the dehydrated crystallized copolymer squeeze treatment along with the follow-up coil tubing heated acid stimulation was an effective technique to address the poor well performance. The operator's 30-day payout on the treatment exceeded expectations and set a new conformance standard. Nine months post-treatment, offset production increases in excess of 63 BOPD are being observed. CO, injection in Well 7C-11H was reduced to one-half the original rate at the same injection pressure of 1,135 psi. Current production in offset wells indicates continued improvement. Tables 4 and 5, Fig 4

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Table 1
Well Information and Description

Formation Name:	San Andres (E Zone)
Formation Type:	Dolomite
Well Temperature:	100 °F
Well Depth:	4,689 ft (TVD) 6,244 ft (TLD)
Out of Zone Injection Interval Depth:	6,025 – 6,100 ft (TLD)
Well conditionltype:	Openhole Lateral Horizontal WAG Injector
Casing:	7" 26# J-55 set at 4,907 ft MD, 4,672 ft TVD Vertical to an estimated depth of 4,350 ft
Tubing:	3 1/2" Lined Injection String, 2.770" ID 2.875: J-55 IPC to 4,898.2 ft - 2.770" ID thru tubing connection 2.670" ID, Drift ID = 2.375"
Tubing Capacity:	(0.3041 gal/ft) = 1,489 gals. (35.5 bbls.)
Open Hole:	4,907 to 6,244 ft MD 1,337 ft of 6-1/8" hole
Openhole Capacity:	(1.5306 gal/ft)
Bottom of Assembly:	7" packer attached to tubing X Nipples (2.313" ID) before and below packer
Injection rate prior to treatment:	3,535 mscfd CO_2
Injection pressure prior to treatment:	1,135 psi
Maximum surface injection pressure:	1,300 psi
BHP:	2,410 psi
Injection problems:	Out-of-zone injection Entry at 6,060-6,130 ft MD indicated to be entering and going down thru fractures into lower San Andres
Water/Oil Contact:	±4,720 ft

Table 2
Rock Mechanical Properties Profile from Stress Log in Adjacent Well 7-10

Interval	Zone	Stress (psi)	Dyn. Young's (psi)	Static Youngs (psi)	Poisson's ratio	Stress Gra (psi/ft
4500-4550	Anhyd.	3012	12.9	6.4	0.3	0.666
4550-4571	Anhyd.	2787	14	7	0.3	0.611
4571-4591	SandIAn.	3045	9.2	4.6	0.27	0.665
4591-4612	G	2820	14	7	0.29	0.613
4612-4625	Dol/An.	2767	13.4	6.7	0.3	0.6
4625-4642	F	2957	10.2	5.1	0.3	0.638
4642-4647	SandIAn.	2526	9	4.5	0.23	0.544
4647-4710	E	3197	7.3	3.6	0.32	0.683
4710-4783	D	2994	8.2	4.1	0.3	0.631
4738-4743	SandIAn.	2788	8.2	4.1	0.26	0.588
4743-4756	C	3181	8	4	0.32	0.67
4756-4761	SandIAn.	2847	7.8	3.9	0.26	0.598
4761-4829	B	2949	9.4	4.7	0.31	0.615
4829-4865	A	2846	10	5	0.29	0.587

Table 3
Solubility and Reaction Rates

					Test 1 Reaction			**Test 2** Solubility	**Test 2** Solubility
					Temp deg **F**	Temp deg F	Temp deg F		
	Core Description	Depth	core poro %	core perm mD	**95°F**	**115°F**	**135°F**		
					% loss	% loss	% loss	%sol as $CaCl_3$	%sol as $CaCl_3$
G zone	Dolo, Anhy, ool	4596	2	0.01	7.6	17.9	19.2	82	49.2
Upper E	Dolo, sl anhy, si frac	4678	9.3	1.44	26.3				60
Lower **E**	Dolo, sl anhy, pp	4697	9.7	6.04	53.7				60
Between C & D zone	Sd, v dolo	4733	12.2	0.17	2.6	7.7	7.7	49.5	29.7
C zone	Dolo, sl anhy, vuggy, vert frac	4745	15.5	831	95	90.7	96.1	100	60

Table 4
Offset Production Prior to Conformance Treatment

Site	Test Date	Oil Rate	Water Rate	Gas Rate
# 7-01	811990 – 712001	23.2	84.7	126.3
# 7-02	811990 – 712001	2.4	56.5	6.5
# 7-05	811990 – 712001	6.0	127.2	43.9
# 7-08	811990 – 712001	16.5	531.7	26.4
# 7-10	611993 – 712001	7.0	50.4	23.9
# 7-13L	1011996 – 712001	23.9	40.9	81.2
# 7-15	1011996 – 712001	12.4	120.6	16.7
Offsets		91.4	324.9	1012.0
Offsets	8/1990 – 7/2001	91.4	324.9	1012.0
# 7-13L	1011996 – 712001	17.0	27.0	77.2
Corrected	10/1996 – 7/2001	74.4	297.9	934.8

Table 5
Post Treatment Offset Production [11-2002]

Site	Test Date	Oil Rate	Water Rate	Gas Rate
# 7-01	8/24/2002	16	13	288
# 7-02	9/19/2002	8	395	27
# 7-05	10/5/2002	11	446	30
# 7-08	9/29/2002	32	84	134
# 7-10	8/18/2002	9	158	99
# 7-13L	10/1/2002	58	58	214
# 7-15	8/21/2002	26	143	222
Offsets		160	1297	1014
Offsets		160	1297	1014
# 7-13L	10/1/2002	58	58	214
Corrected		131	1268	907

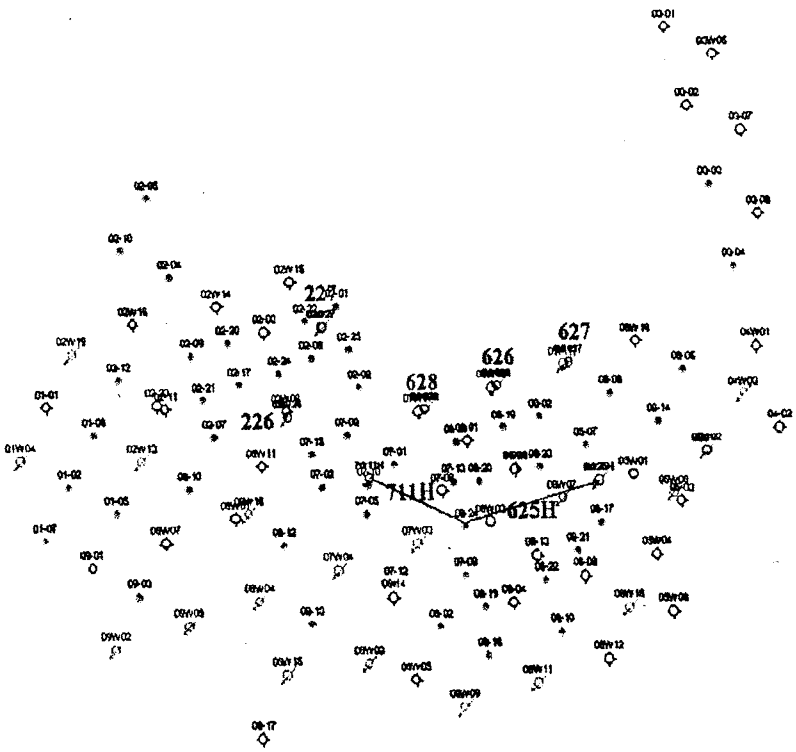

Figure 1 - SCU Unit Highlighting the Initial Horizontal CO, WAG Injectors

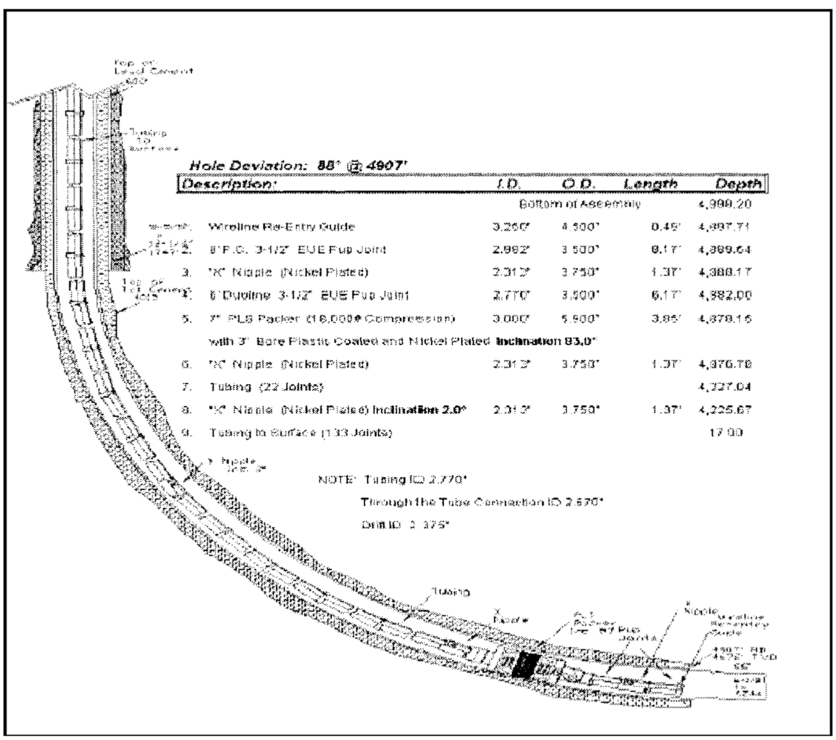

Figure 2 - Wellbore Schematic Horizontal Injection Well 7C-11H

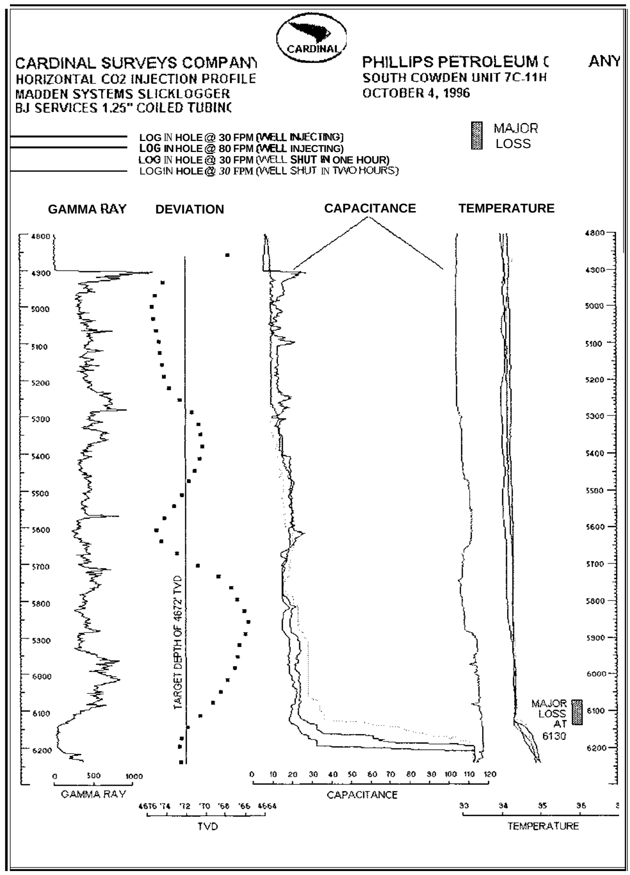

Figure 3 - Major Loss of Injectant Identified on Well 7C-11H

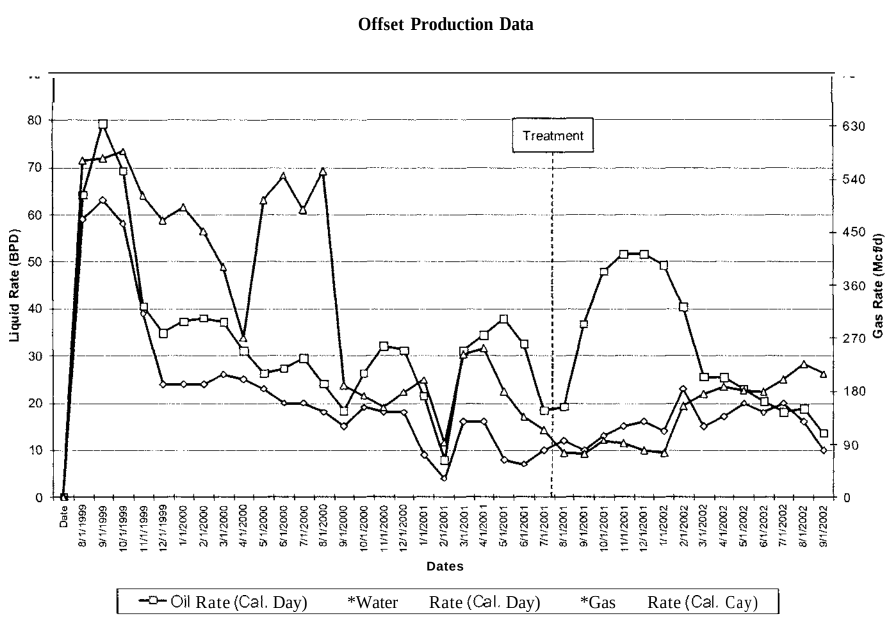

Figure 4 - Historical Production on Offset Producers of Well 7C-11H