PROBLEM IDENTIFICATION AND IMPROVED TREATMENT SOLUTION METHOD OF A HIGH-PERMEABILITY THIEF ZONE

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Abstract

During a pilot evaluation of a CO_2 water-alternating-gas (WAG) injection performed in the west Texas San Andres formation, operators discovered that CO_2 and water injections were being lost to a high-permeability layer in the upper portion of the formation. This problem was indicated by profile data and a lack of offset production-well responses. No offset producers indicated the presence of CO_2; however, CO_2 was discovered in an abandoned temporary injection well located 2 $^1/_4$ miles from the communicating injector. This discovery meant that, rather than reaching their target destination, injection fluids were traveling to the abandoned well through a high-permeability thief zone.

Operators determined that a chemical treatment must be used to seal the thief interval. Because of the unique conditions in the San Andres formation, the chemical treatment had to be able to do the following:

- withstand continual injection of alternating water/CO_2 with the production of carbolic acid
- resist degradation caused by bacterial growth
- provide a low-viscosity fluid capable of deeply penetrating the thief interval
- withstand pressure extrusions
- withstand intermixing caused by crossflows
- be removable (if necessary)

Multi-rate injections and profiled entry analysis established the following additional criteria for the treatment candidate and its placement:

- Injection must occur at a precise rate and without additional pressure resistance beyond that typical of the CO_2/WAG. This method would ensure that the treatment enters only the problem interval.
- The treatment must be placed deep enough to prevent the CO_2/WAG injections from re-entering the thief interval.

After CO_2 was discovered in the abandoned well, two production wells were studied. These studies determined that 100% of the fluid injected into these wells was being lost to a 10-ft thief interval in the upper portion of the payzone. After treatments were applied, the thief zones in these two wells were shut off, and the injections reached their target reservoirs. Because this action required fluid entry into more restrictive permeabilities, injection pressure was increased to flood the payzones more effectively.

This paper discusses the laboratory investigations that helped operators choose an optimal treatment for sealing the thief intervals. Placement techniques and field results, which indicate modified injection profiles, are also provided.

Formation Geology

The flood unit is located in the north central platform of the Permian Basin. Reservoirs in the Permian San Andres carbonates on the northern shelf of the central basin platform are typically composed of interbedded dolomite, anhydrite, siltstone, and salt. The San Andres formation exhibits widespread occurrences of porous dolomite deposited under subtidal conditions. Hydrocarbon traps are structural and combined structural/stratigraphic formations. Porosity and permeability are directly related to the depositional and diagentic phases that the formation has undergone. Intercrystalline, leached, and fracture porosity occur primarily in wackestones.

Fig. 1 illustrates the pay intervals of the Sand Andres formation. Several transgressions in this formation are characterized by multiple layers that have discontinuous areas caused by widespread impermeable layers. Currently, most recovery in the central platform can be attributed to pressure maintenance initiated by water and miscible floods performed with CO_2. Permeability contrasts throughout the formation are responsible for the varying effectiveness of water and CO_2 injections.

Problem Identification and Diagnostics

A diagnostic analysis of the candidate wells was conducted so that the causes of injection-fluid loss could be determined. The wells were simultaneously subjected to multi-rate injectitivities and profiled entry analysis. A lack of response from offset wells was also noted. The range of injection rates, corresponding bottomhole injection pressures, and possible changes in entry suggested that most of the injectant was entering the high-permeability thief interval up to the parting pressure of the formation.

Well 1. The first well investigated had an injection rate between 150 and 300 BWPD and a bottomhole injection pressure (BHIP) of 4,575 psi (complete well data is presented in **Table 1**). Analysis verified that 100% of the fluid being injected into this well was traveling to an abandoned well through a high-permeability streak located at a depth of 5,165 to 5,175ft. While the average permeability of the formation was 0.5 md, the estimated permeability of the thief interval was 10 md. Because liquids and gases flow through paths of least resistance, the CO_2 was naturally migrating into the thief interval. However, because a 10-md zone is still considered a low-permeability zone, conventional solutions could not be used as sealants for this zone.

Well 2. Investigations of the second well verified an injection rate of 245 BWPD with a BHIP of 4,550 psi (complete well data is presented in **Table 2**). As with Well 1, 100% of the injectant was entering and travelling through a high-permeability streak located at approximately 5,173 ft. Again, this streak had an average permeability of 10 md, while the surrounding formation had a permeability of only 0.5.

Analysis of these two wells influenced the injection rates and pressures necessary for placing sealant into the thief zones while minimizing entry into other portions of the flood interval. After the injectivity analyses, the possibility of crossflows was also analyzed at static conditions.

Solution Criteria

After the communication problems of the two wells were identified, criteria were set for selecting an optimal, cost-effective treatment. According to diagnostics and injectivity analyses, an ideal treatment, one that would deeply enter and seal the thief zones, had to be injected at a precise rate with nominal pressure resistance. The chemical treatment best suited for this purpose had to be able to do the following:

- withstand the acidic environment created by continued injections of CO_2/water
- resist degradation caused by bacterial growth
- provide a low-viscosity fluid that can be easily placed deep within the formation
- develop sufficient in-situ gel strength to resist pressure extrusions
- withstand crossflow intermixing during and after placement
- be removable (if necessary)

Methods of Treatment Selection

Several treatment options were considered and rejected. Metal-crosslinked polymers were discounted because of their inherent viscosity and because of possible compatibility problems with CO_2. Silicate systems were excluded because of their uncontrolled, rapid gelation in a low-pH environment and their interaction with divalent salts in formation brine water. In addition, silicates are not removable. Cement squeezes were rejected because of their inability to penetrate the thief interval. Such treatments would provide thief-zone blockage at the formation face only. CO_2 would quickly divert around any near-wellbore seal and flow back into the thief interval a short distance from the wellbore.

After the treatment options were analyzed, an in-situ-generated polymer (IGP) system was chosen to seal the thief zones. In addition to meeting the originally established solution criteria, the IGP provided the following advantages:

- a thermally controlled activator that allows gelation times to be adequately controlled
- water-like viscosity for easy injection
- fluid that does not divert or react prematurely

IGP Descriptive Profile

The IGP conformance-control system consists of a low-toxicity, acrylate monomer and a thermally controlled azo activator. The system also includes potassium chloride (KCl); fresh, potable water, and a pH adjuster. These components provide a standardized ionic concentration and a pH ambience ideal for in-situ polymerizing. The additional components also help make IGP compatible with formation conditions.

Customization. The mixing concentration of IGP can be customized for specific conformance problems. Formulated combinations establish ultimate viscosity, solubility, strength in the downhole environment, and the final nature of the system, which can range from a strongly crosslinked, ringing gel to a viscous polymer slug.

Activator. The azo activator is a compound that undergoes thermal degradation (a process that causes the activator to form free radicals) to initiate in-situ polymerization of the monomer. Because monomer solutions can gel prematurely in the combined presence of free radicals and transition metals (iron, cobalt, etc.), the azo compound requires a specific temperature for forming free radicals. The specific activator for the fluid system must be based on design temperature, which is dependent on well conditions. Azo initiators provide a wide range of gel times, ranging from 1 to 20 hours at temperatures between 70° and 150°F (21.1° to 65.5°C).

Laboratory Testing Apparatus

Benchtop Model. During the diagnostic and design process, a laboratory benchtop model was constructed that simulated formation conditions (**Fig. 2**). Flow tests helped determine the effectiveness of the proposed IGP treatment fluid. A system was also constructed that helped indicate the fluid's degradation resistance in the presence of supercritical CO_2 ($\cong$ 1,500 psi at 120°F). In this system, a laboratory feed pump transferred liquid CO_2 from the storage cylinder to the test equipment while maintaining 1,500 psi. The liquid CO_2 was precooled by a coil located on the intake side of the pump. A submersible laboratory pump circulated antifreeze at 32°F through the coil. This system allowed the liquid CO_2 to maintain prime with the pump. A carbon dioxide reservoir stored in a temperature bath at 120°F transformed the liquid CO_2 into supercritical CO_2 by means of vaporization. A high-pressure regulator then adjusted the gas to the necessary test pressure.

Test Medium. A test-core holder and a flow system were constructed to serve as the test medium. The system was built with high-pressure, stainless-steel fittings, valves and tubing that would withstand pressures over 2,000 psi and would provide corrosion and pressure control. The flow system was designed so that flow rates for both water and CO_2 could be determined. Heating jackets and controllers maintained a temperature of 120°F, and a backpressure regulator maintained pressure at 1,500 psi.

A 200-psi, differential-pressure transducer monitored the pressure between the inlet and outlet points of the test cell. Backpressure and gas-flow regulators were submerged in a 125°F bath, which compensated for heat loss caused by the expansion of CO_2 (as described by the Joule-Thompson effect). A precision gas-flow regulator subjected effluent gas to a constant, predetermined pressure as the gas passed through a liquid/gas separator, a drying chamber, and a mass flowmeter.

Laboratory Test Procedure.

In the laboratory, researchers used the following procedure to test the effectiveness of the IGP system:

1. The test core was placed in a Hassler sleeve.
2. System pressure was adjusted to 1,500 psi, and temperature was adjusted to 120°F.
3. Under stable flow conditions, API brine (9% NaCl + 1%$CaCl_2$) and kerosene were sent through the core in alternating sequences until the permeability variations caused by the relative saturation levels of oil and water reached acceptable limits.
4. The effective permeability of the API brinewas determined.
5. The core was stabilizedto the flow of supercritical CO_2.

6. The flow of API brine through the corewas stabilized. This value was used to benchmark the initial permeability to brine that would be used in the test.
7. The core was treated with 100 mL of the IGP solution and shut in for 48 hours to allow in-situ polymerization of the system.

Evaluations were also conducted with API brine and supercritical CO_2 cycled to stable flow. Results of these tests are shown in **Table 3** and **Fig. 3**

Treatment Design

A "fuzzy-logic" computer program for designing water-control methods helped users formulate treatment designs. This program incorporates solutions, techniques, and treatment volumes. Based on diagnostic and injectivity results, the IGP system could be most successfully placed with a bullhead technique. Before the IGP system was placed, data based on well spacing, injection rates, and breakthrough parameters were also considered. This arrangement used the knowledge of water-conformance personnel in the field as well as the laboratory. While the computer program contained many common engineering methods for calculating values, it also helped reveal patterns based on relevant, existing data.

Quality Control

In the laboratory, downhole injection temperatures were usedfor determining the gelation time required for the monomer to react. Intermixing the monomer with injected water did not appear to have any adverse effects on gelation time. Variations in gelation times were determined so that modifications made during placement could shorten the reaction time to make it coincide with final placement and help prevent the possible influx of a problematic crossflow trend.

Treatments

Because the monomer provided a water-like viscosity, high injection pressure could be used to place the IGP treatment deep into the permeable rock. In-situ polymerization time was dictated by downhole injection temperature and initiator concentration. Because the initiator system is activated by high temperatures, the probability of premature gelation is very low. For the treatment process, a preflush solution consisting of 2,000 gal of 2% KCl water was injected into the formation to help remove oxygen. A similar solution was used to displace the IGP treatment from the tubing to the perforations at the thief interval. Each treatment consisted of 4,000 gal of IGP that had been batch-mixed in a clean transport. The initiator was added to the IGP immediately before it was injected into the well.

Results

The IGP treatment used in Well 1 successfully sealed the thief zone. Injection profiles performed after the treatment indicated that CO_2/WAG was being applied uniformly throughout the remaining payzone (at an increased pressure, which was necessary to maintain previous injection rates). **Table 4** and **Fig. 4** provide detailed data gathered before and after the IGP treatment. The IGP treatment also successfully sealed the thief zone in Well 2; however, previous scale damage to the remaining payzone required a followup acid treatment. Itemized data collected before and after the IGP treatment of this well are provided in Table 4. Well 2 is also a candidate to be deepened, which would expose more of the reservoir to flooding.

Conclusions

Pretreatment diagnostics based on multi-rate injectivities and profiled entry analysis allowed an IGP water-control treatment to be successfully planned. Injectivity analysis also helped determine proper IGP placement. Consequently, the thief zones in two wells were isolated, allowing CO_2/WAG injections to enter the low-permeability target zones. Based on the modified injection path, the offset response is expected to increase hydrocarbon production significantly.

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Acknowledgments

We would like to thank Halliburton Energy Services, Inc., for allowing us to prepare and present this paper.

Table 1 - Data for Well 1

Well Type	Injector
Formation	Chamliss
Formation Type	Dolomite
Casing	4 $^{1}/_{2}$ in., 10.5 lb
Casing Depth	± 5,500 ft
Tubing	2 $^{3}/_{8}$-in., 4.7-lb, J-55 CL
Packer	at ± 5,070 ft
Perforations	5,165 to 5,310 ft
Stimulation History	Acidized with 13,500 gal HCl
Injection Rates	1990 to June 1996 (± 150 to 300 BWPD)
BHIP	± 4,575 psi
Surface Injection Pressure	± 2,200 psi
BHSP	± 4,300 psi
BHIT	115°F
Apparent Problem	High-permeability streak
Squeeze Rate	± 8gal/min
Squeeze Down	Injection string under injection packer

Table 2 - Data for Well 2

Well Type	Injector
Formation	Chamliss
Formation Type	Dolomite
Casing	4 $^{1}/_{2}$ in., 10.5 lb
Casing Depth	± 5,500 ft
Tubing	2 $^{3}/_{8}$-in., 4.7-lb, J-55 CL
Packer	at ± 5,120 ft
Perforations	5,173 to 5,305 ft
Stimulation History	Acidized with 14,500 gal HCl
Injection Rates	Sept. 1994 to April 1996 (± 245 BWPD)
BHIP	± 4,550 psi
Surface Injection Pressure	± 2,220 psi
BHSP	± 4,300 psi
BHIT	115°F
Apparent Problem	High-permeability streak
Squeeze Rate	± 1 to 2 gal/min
Squeeze Down	Injection string under injection packer

Table 3 - IGP Compatibility with CO_2

Physical Data	
System Pressure	1,500 psi
Rock	Berea sandstone
Core Diameter	2.4 cm
Core Length	9.99 cm
Test Temperature	120°F
Viscosities (cp) at Temperature	
API Standard Brine	0.69
Kerosene	1.15
CO_2	0.0175 (estimated)

Table 4 - Flow-Test Results

Fluid	Cumlative Volume (mL)	Flow Rate (mL/min)	ΔP (psi)	Calculated Permeability (md)	Total Cumulative Volume (mL)	Average Permeability (md)
API brine	200	9.20	48	72.30	200.0	71.3
	600	8.30	44	70.40	600.0	
	650	8.10	42	72.00	650.0	
	700	7.90	42	71.10	700.0	
	750	8.00	42	72.00	750.0	
	800	7.90	42	70.20	800.0	
Kerosene	300	3.60	31	73.40	1100.0	78.2
	350	3.20	27	75.10	1150.0	
	400	3.60	28	80.00	1200.0	
	450	3.70	28	82.20	1250.0	
	500	3.60	28	80.00	1300.0	
API brine	500	0.88	45	7.40	1800.0	7.4
	550	0.92	46	7.50	1850.0	
	575	0.93	46	7.60	1875.0	
	625	0.87	44	7.40	1925.0	
	650	0.89	45	7.40	1950.0	
Kerosene	300	5.20	24	134.80	2250.0	133.4
	400	5.00	23	133.50	2350.0	
	450	4.90	23	132.60	2400.0	
	500	4.90	23	132.60	2450.0	
API brine	175	1.40	39	13.40	2626.0	13.4
	200	1.40	39	13.40	2650.0	
	250	1.40	39	13.40	2700.0	
Kerosene	775	5.30	27	122.10	3475.0	123.7
	800	5.40	27	124.40	3500.0	
	825	5.40	27	124.40	3525.0	
API brine	100	1.90	29	24.90	3625.0	24.9
	150	1.90	29	24.90	3675.0	
Kerosene	750	5.30	24	140.30	4425.0	141.2
	775	5.40	24	143.00	4450.0	
	800	5.30	24	140.30	4475.0	
API brine	150	1.90	27	26.80	4625.0	26.8
	200	1.90	27	26.80	4675.0	
	250	1.90	27	26.80	4725.0	
CO_2	1020	3.00	2	14.20	5745.0	14.2
API brine	200	3.40	14	90.70	5945.0	91.3
	250	3.40	14	90.70	5995.0	
	300	3.50	14	93.30	6045.0	
	325	3.40	14	90.70	6070.0	
IGP Treatment	100				6170.0	
API brine		0.00	15		6170.0	1.9
	20	0.13	26	1.90	6190.0	
CO_2	60	0.15	16	0.10	6249.8	0.1
API Brine	35	0.53	23	8.60	6284.8	8.6
	100	0.53	23	8.60	6349.8	
CO_2	43	0.03	2	0.20	6393.2	0.2
API brine	125	0.75	28	10.00	6518.2	10.1
	150	0.77	29	9.90	6543.2	
	225	0.88	31	10.60	6618.2	
	250	0.81	30	10.10	6643.2	
	300	0.77	29	939.00	6693.2	
CO_2	64	1.07	14	0.70	6757.2	0.6
	96	1.07	12	0.80	6789.2	
	146	1.67	19	0.80	6839.2	
	176	1.00	10	0.90	6869.2	
	212	1.20	12	0.90	6905.2	
	252	1.33	14	0.90	6945.2	
	285	1.10	11	0.90	6978.2	
	297	0.41	21	0.20	6990.6	
	300	0.08	17	0.00	6993.0	
	301	0.03	79	0.00	6993.8	
	301	0.02	84	0.00	6994.4	
	317	1.60	20	0.80	7010.4	
	327	0.93	13	0.70	7019.7	
	343	1.60	20	0.80	7035.7	
	347	1.33	15	0.80	7039.7	
API brine	50	0.84	28	11.20	7089.7	11.0
	100	0.78	29	10.00	7139.7	
	150	0.89	29	11.50	7189.7	
	200	0.89	29	11.50	7239.7	
CO_2	32	1.07	18	0.60	7271.7	0.7
	82	1.67	24	0.70	7321.7	
	126	1.47	21	0.70	7365.7	
	172	1.53	24	0.60	7411.7	
	220	1.60	22	0.70	7549.7	
	262	1.40	20	0.70	7501.7	
	290	0.93	16	0.60	7529.7	
	314	0.80	14	0.50	7553.7	
	356	1.40	18	0.70	7595.7	
	412	1.87	24	0.7	7651.7	
	452	1.33	18	0.7	7691.7	
	500	1.60	20	0.8	7739.7	
	548	1.60	20	0.8	7787.7	
	558	1.00	16	0.6	7797.7	

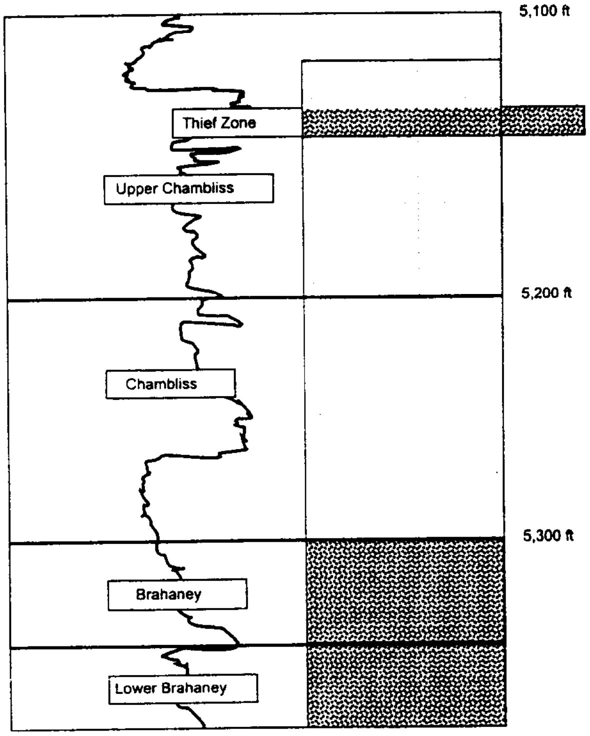

Figure 1 - San Andres (Chambliss) Formation Pay Intervals

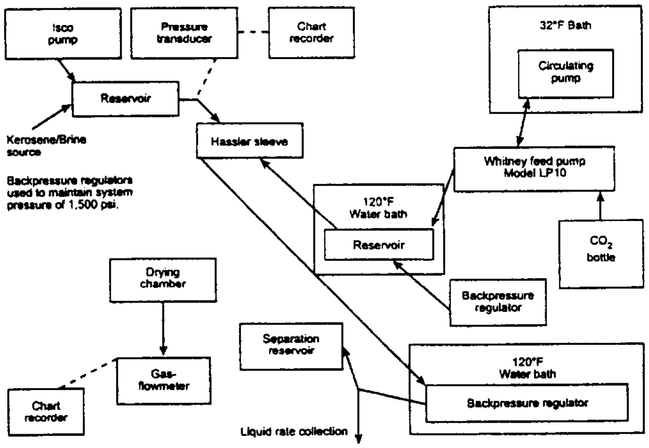

Figure 2

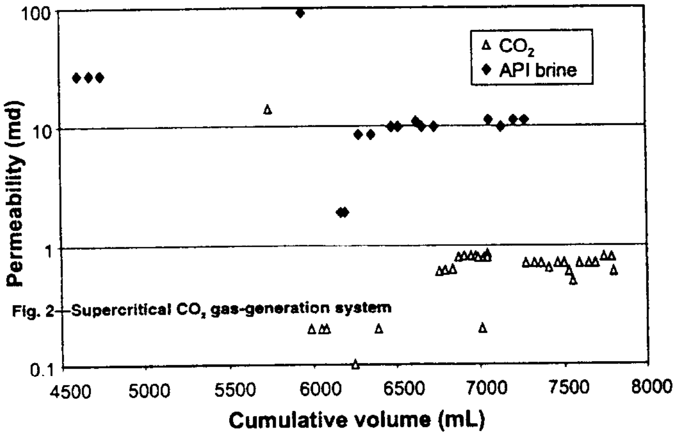

Figure 3 - CO_2/WAG Flow Study for IGP

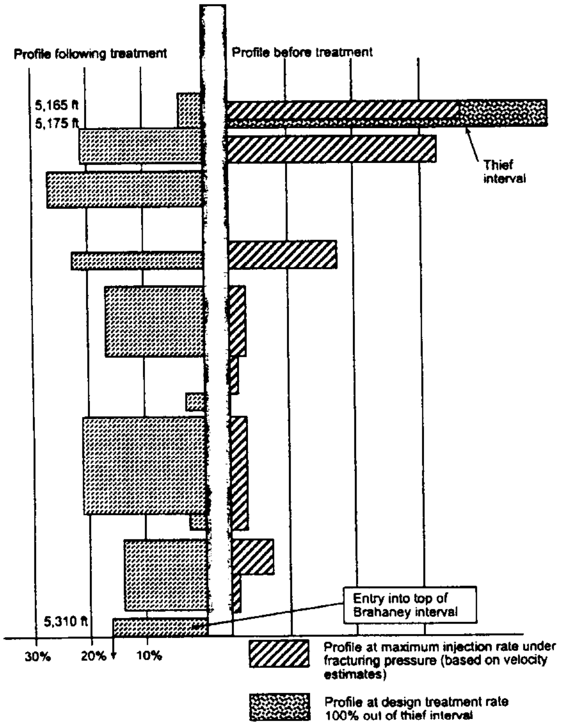

Figure 4 - Pretreatment and Post-Treatment Profile, San Andres Formation