CARBONATE ACIDIZING IN THE PERMIAN BASIN: CASE HISTORIES

Steve Metcalf, Bob Weaver, Sabino Orona and Gary Kretzschmer
BJ Services Company, USA

ABSTRACT

Carbonate formations are predominate in the Permian Basin and as such are commonly stimulated with acids. Success of an acid treatment is dependent on knowledge of the reservoir, design techniques, execution with emphasis on obtaining good zone coverage.

Case histories of acid stimulation, with production results, are presented covering San Andres, Devonian horizontal wells and Ellenburger wells. Treatments varied from high rate matrix to hydraulic fracturing operations. Discussed are key issues to overcome in order to obtain an effective stimulation and methods employed, with particular emphasis on zonal coverage.

BACKGROUND

Stimulation of carbonate reservoirs is typically used to restore or enhance production to an economic level. Acid, whether organic or inorganic in nature is a natural means of effecting such stimulation of these types of lithologies.[1-8] Acid Fracturing is the most widely used technique for deep stimulation of limestone or dolomite formations. Matrix treatments whether at a minor injection rate (low permeability reservoirs) or at high rates (high permeability reservoirs) is also commonly used to effect a shallow damage bypass. San Andres, Devonian and Ellenburger formations common carbonate reservoirs producing in the Permian Basin with lithologies, depths and bottomhole temperatures that vary significantly. In addition, horizontal completions are becoming routine in some areas where these formations are being produced.

GEOLOGIC DESCRIPTIONS

San Andres

The San Andres (~5,700 feet) is a dolomitic formation with solution gas drive in combination with gas cap expansion.[9-10] Average permeability is over 9 md with an average porosity greater than 13%. Acid solubility varies from 78 to 92% in 15% hydrochloric acid. The main components of the lithology are dolomite (77 to 92%) and Anhydrite (3 to 20%). These values are illustrated in **Figure 1.** Bottomhole temperature is typically around 100°F.

Devonian

Microscopic examination of core samples from three wells (~8,400 feet) in the area of the treated wells revealed a mixture of the following lithologies: chert, cherty limestone, limey chert, dolomitic cherty limestone and dolomitic limey chert. Micro porosity rather than interparticle porosity has been created by partial substitution of the original limestone matrix by silica (chert). The depositional processes included karst weathering, cave wall deposition and collapsed cave material accumulating as brecciated chert zones.[11-13] **Figure 2** illustrates the variance of the composition through the Devonian interval of interest. Permeability varied from less than 0.01 md to greater than 16 md with an average of approximately 2 md. Porosity varies from less than 1 to greater than 13 % with an average of approximately 11 %. Bottomhole temperature is generally around 135°F.

Ellenburger

Core samples from a Val Verde County, Texas Ellenburger (~15,000 feet) well covering 1200 feet of interval were found to have solution collapse breccia, along with dolomitized limestone (Ankerite) and clearly defined bedding structures.[14] Widely variable sorting of angular fragments ranging in size from coarse-grained sand-like particles to large cobbles greater than eight inches in diameter. Shallower samples exhibited vugs between the framework fragments. The presence of natural fractures indicates tectonic activity and since some of the older natural fractures are cross-cut by newer fractures indicates at least two periods of tectonic activity have occurred. These fractures varied in width from micro to over one half inch. These natural fractures are generally filled with authigenic precipitates (Calcite, dolomite and quartz). There were some open micro fractures that were incompletely filled by mineralization and probably represent the last tectonic episode. **Figure 3** breaks down the variance in composition with depth. Permeability varied from 0.1md to over 10 md with porosity varying from 0.5 to 4.6 %, with averages of 2.39 md and 1.51 % respectively. Bottomhole temperature in this area is over 300°F.

This paper presents the details surrounding the treatments of wells completed in each of these formations. Included, are the design factors to effect improved production, the limiting factors to successful treatments, and the resulting production responses.

SAN ANDRES CASE HISTORY

Several horizontal wells in the San Andres have been completed in 2006 and stimulated similar to this case history. This well was initially completed as a vertical well drilled, perforated and hydraulically fracture stimulated with 43000 pounds of 16/30 mesh white sand, in February 2006. Lower than expected production resulted. Re-completion utilizing a horizontal wellbore drilled in the center of the vertical pay zone in July-August and a large acid job performed in four stages in September 2006 was carried out.

Stimulation Requirements

The horizontal wellbore provides a significant producing surface area with the potential to connect many natural fractures. In addition, a larger area may be drained without drilling additional wells. However, in order to produce the well, damage from the drilling operations should be cleaned up or bypassed.

Limiting Issues

As these are openhole completions the effective coverage of any stimulation fluid through the interval is an extreme challenge. Bottomhole temperature is low (~100°F) and therefore reactivity control is a concern from the standpoint of obtaining effective dissolution before fluids are recovered. The temperature in combination with the dolomitic composition (slower reacting) is the reason for concern. Treating fluids have to have reactivity sufficient enough to accomplish stimulation and still create diversion to cover the intervals in each stage.

Treatment

The treatment pumped is outlined in **Table 1**. **Figure 4,** illustrates the rates and pressure responses through each stage. With every diversion stage a significant pressure increase was observed, indicating diversion of treating fluids in new intervals. Viscoelastic acid systems allow for good reactivity and effective diversion based on rapid viscosity increase within the formation forcing subsequent acid stages to be diverted to the next path of least resistance.

Production Results

Figure 5 reflects the production response following both the vertical completion and the horizontal. Production after the initial vertical completion was 7 BOPD declining rapidly to 3 BOPD. After stimulation of the horizontal wellbore production was level at approximately 50 BOPD and 8 BWPD and has declined slowly over the last four months to over 30 BOPD and 3 BWPD.

DEVONIAN CASE HISTORY

In the field of Ector and Winkler Counties, Texas several wells exist vertically to produce the Devonian Formation. In 2006 several horizontal wellbores were drilled in this area to increase production rates and more effectively drain the acreage. This reduces overall expenses by drilling fewer vertical wells to drain the same acreage. The vertical wells in the area have been producing two to four years, except for the initial well in the field which has been producing 20 years. Average cumulative production for the 28 newer vertical wells is 31.2 MBO and 94.1 MMCF. These wells have been typically treated with 2,000 to 37,000 gallons of 15% hydrochloric acid with an average of approximately 14,850 gallons. Seven wells were hydraulically fractured with an average of 53,000 pounds of proppant.

Stimulation Requirements

The horizontal wellbore provides a significant producing surface area with the potential to connect many natural fractures. However, in order to produce, damage from the drilling operations should be cleaned up or bypassed. This also means a larger surface area for loss of treating fluids and a great deal of loss in control of placement.

Limiting Issues

Since this is an openhole completion the effective coverage of any stimulation fluid through the interval is an extreme challenge. The bottomhole temperature of ~135°F should have little effect on control issues in that reaction of acid with the carbonate portions of the formation rock will be at a moderate rate. However, due to the large concentration of chert (Insoluble in hydrochloric acid) in the formation, reactivity is somewhat reduced. Treating fluids must control leak-off and still effect diversion.

Treatment

One of the treatment schedules utilized is listed in **Table 2**. **Figure 6,** illustrates the rates and pressure responses through the stages. The four stages pumped all treated at different surface treating pressures at approximately the same rate indicating that different paths of fluid entry into the reservoir were being created. Within each stage pressure responses of the diversion fluid can be seen. In this instance extreme viscosity is the key to diversion and fluid leak-off control.

Production Results

Figure 7, reflects the production history of one of the wells treated as described. To date five horizontal wells have been treated, three as described (one with dual laterals). **Table 3** lists the five wells with cumulative production and days producing. Where the 28 newer vertical wells discussed earlier have produced two to four years with average cumulative production of 34.2 MBO and 94.1 MMCF it can be seen in **Table 3** that these five horizontal wells in an average of 212 days have produced an average cumulative of 39.9 MBO and 94.6 MMCF. This illustrates the significant improvement in drainage of acreage with fewer total wellbores.

ELLENBURGER CASE HISTORY

Wells completed in the area in 1978 through 1979 were typically stimulated with 20,000 to 51,000 gallons of 20% hydrochloric acid and in two cases were fraced with 43,500 to 90,000 pounds of sand. Typically these older wells were treated in two to four segments with production tests in between. These wells have produced from 1 to 10 BCF to date.

Stimulation Requirements

Natural fractures and vugular porosity intervals within this massive dolomite reservoir need interconnection and surface area to produce gas at an economic rate.

Limiting Issues

The biggest challenge to effective stimulation is reactivity control at the bottomhole temperature of over 300°F. The next challenge is the fact that this is a massive producing interval from 1200 to 1500 feet in thickness, which means some form of diversion, whether mechanical or with diverting materials, is required. Since it is cased and perforated, ball sealers are one solution. Another is to isolate intervals either with packers and pump through sleeves or set plugs between stages and then perforate the next interval moving up the hole.

Treatment

A multi-stage treatment, **Table 4,** was pumped on two of the wells in the area. The other three wells treated with a multi-stage sequence involved the setting of plugs and subsequently perforating the next interval. One of the three wells treated with plugs was stimulated with three stages while the other two were stimulated with four. This method takes a great deal more time and is much more costly. However, it does allow for a higher degree of accuracy on the placement of the stimulation. **Figure 8,** illustrates the rates and pressure responses through the stages of a treatment outlined in **Table 4**.

A typical single-stage treatment, **Table 5,** was pumped on five additional wells in the field. **Figure 9,** illustrates the rates and pressure responses as ball sealers diverted the treatment over the large perforated interval. While this method allows for a shorter time period to complete the disadvantage is not knowing for sure where the stimulation treatment entered the formation.

Production Results

Figures 10 and 11 shows the production response following the Multi-stage and the Single-stage treatments respectively. To date nine wells have been treated, four with multi-staging and five with the single stage treatments. **Table 6** lists the nine wells with cumulative production and days producing.

CONCLUSIONS

1. Horizontal Devonian well can achieve greater early time production than vertical wells.
2. Acid treatments can effectively stimulate carbonate formations or bypass drilling damage to facilitate economic production.
3. Understanding of the issues which must be overcome to make an acid treatment effective is essential.
4. Large intervals can be stimulated successfully when good diversion techniques are utilized.

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Table 1 San Andres – Horizontal Treatment Schedule			
Stage	**Stage Function**	**Fluid Description**	**Volume, gals**
1	Pump down first ball to open end of tubing and establish injection rate.	Slickwater	2000
2	Initiate Stimulation	15% Slick HCl	1750
3	Diversion	Viscoelastic 20% HCl	500
4	Initiate Stimulation	15% Slick HCl	2000
5	Diversion	Viscoelastic 20% HCl	750
6	Initiate Stimulation	15% Slick HCl	2250
7	Diversion	Viscoelastic 20% HCl	1000
8	Initiate Stimulation	15% Slick HCl	2500
9	Pump down ball to open first sleeve.	Slickwater	500
10	Breakdown next interval	15% Slick HCl	250
11	Establish injection rate	Slickwater	1500
12	Initiate Stimulation	15% Slick HCl	1500
13	Diversion	Viscoelastic 20% HCl	500
14	Initiate Stimulation	15% Slick HCl	2000
15	Diversion	Viscoelastic 20% HCl	750
16	Initiate Stimulation	15% Slick HCl	2250
17	Diversion	Viscoelastic 20% HCl	1000
18	Initiate Stimulation	15% Slick HCl	2500
19	Pump down ball to open second sleeve.	Slickwater	500
20	Breakdown next interval	15% Slick HCl	250
21	Establish injection rate	Slickwater	1500
22	Initiate Stimulation	15% Slick HCl	1500
23	Diversion	Viscoelastic 20% HCl	500
24	Initiate Stimulation	15% Slick HCl	2000
25	Diversion	Viscoelastic 20% HCl	750
26	Initiate Stimulation	15% Slick HCl	2250
27	Diversion	Viscoelastic 20% HCl	1000
28	Initiate Stimulation	15% Slick HCl	2500
29	Pump down ball to open third sleeve.	Slickwater	500
30	Breakdown next interval	15% Slick HCl	250
31	Establish injection rate	Slickwater	1500
32	Initiate Stimulation	15% Slick HCl	1500
33	Diversion	Viscoelastic 20% HCl	500
34	Initiate Stimulation	15% Slick HCl	2000
35	Diversion	Viscoelastic 20% HCl	750
36	Initiate Stimulation	15% Slick HCl	2250
37	Diversion	Viscoelastic 20% HCl	1000
38	Initiate Stimulation	15% Slick HCl	2500
39	Overflush	Slickwater	500
40	Flush	Slickwater	1373

Table 2 Devonian – Horizontal Treatment Schedule			
Stage	**Stage Function**	**Fluid Description**	**Volume, gals**
1	Breakdown Formation	15% Slick HCl	250
2	Establish Injection Rate	Slickwater	5000
3	Initiate Stimulation	15% Slick HCl	750
4	Diversion	Crosslinked Gelled 15% HCl	3535
5	Initiate Stimulation	Gelled 20% HCl	1365
6	Diversion	Crosslinked Gelled 15% HCl	3535
7	Initiate Stimulation	Gelled 20% HCl	1365
8	Overflush	Slickwater	1500
9	Pump down ball to open first sleeve.	Slickwater	1000
10	Breakdown next interval	15% Slick HCl	250
11	Establish injection rate	Slickwater	5000
12	Initiate Stimulation	15% Slick HCl	750
13	Diversion	Crosslinked Gelled 15% HCl	7445
14	Initiate Stimulation	Gelled 20% HCl	1365
15	Diversion	Crosslinked Gelled 15% HCl	7445
16	Initiate Stimulation	Gelled 20% HCl	1365
17	Overflush	Slickwater	1500
18	Pump down ball to open second sleeve.	Slickwater	1000
19	Breakdown next interval	15% Slick HCl	250
20	Establish injection rate	Slickwater	5000
21	Initiate Stimulation	15% Slick HCl	750
22	Diversion	Crosslinked Gelled 15% HCl	5350
23	Initiate Stimulation	Gelled 20% HCl	1365
24	Diversion	Crosslinked Gelled 15% HCl	5350
25	Initiate Stimulation	Gelled 20% HCl	1365
26	Diversion	Crosslinked Gelled 15% HCl	5370
27	Initiate Stimulation	Gelled 20% HCl	1370
28	Overflush	Slickwater	1500
29	Pump down ball to open third sleeve.	Slickwater	1000
30	Breakdown next interval	15% Slick HCl	250
31	Establish injection rate	Slickwater	5000
32	Initiate Stimulation	15% Slick HCl	750
33	Diversion	Crosslinked Gelled 15% HCl	5565
34	Initiate Stimulation	Gelled 20% HCl	1365
35	Diversion	Crosslinked Gelled 15% HCl	5565
36	Initiate Stimulation	Gelled 20% HCl	1365
37	Diversion	Crosslinked Gelled 15% HCl	5570
38	Initiate Stimulation	Gelled 20% HCl	1370
39	Overflush	Slickwater	1500
40	Flush	Slickwater	5714

Table 3 Devonian – Horizontal Wells Cumulative Production				
Well	**Cumulative Oil, MBO**	**Cumulative Gas, MMCF**	**Days Producing**	**Treatment**
A	30.5	63.0	254	As Described Above
B	43.7	55.8	264	As Described Above
C	85.2	245.0	188	As Described Above
D	18.9	55.4	232	Other
E	21.1	53.7	124	Other

Table 4 Ellenburger – Multi-Stage Treatment Schedule				
Stage	**Stage Function**	**Fluid Description**	**Percent CO_2**	**Volume, gals**
1	Establish injection rate through end of tubing	Slickwater	30%	7,000
2	Diversion	Crosslinked gelled 15% HCl	30%	10,500
3	Initiate Stimulation	Gelled 15% HCl	30%	3,500
4	Diversion	Crosslinked gelled 15% HCl	30%	12,750
5	Initiate Stimulation	Gelled 15% HCl	30%	4,250
6	Diversion	Crosslinked gelled 15% HCl	30%	15,750
7	Initiate Stimulation	Gelled 15% HCl	30%	5,250
8	Overflush	Slickwater	30%	7,000
9	Pump down ball to open first sleeve.	Slickwater	0%	3,000
10	Diversion	Crosslinked gelled 15% HCl	30%	10,500
11	Initiate Stimulation	Gelled 15% HCl	30%	3,500
12	Diversion	Crosslinked gelled 15% HCl	30%	12,750
13	Initiate Stimulation	Gelled 15% HCl	30%	4,250
14	Diversion	Crosslinked gelled 15% HCl	30%	15,750
15	Initiate Stimulation	Gelled 15% HCl	30%	5,250
16	Overflush	Slickwater	30%	6,000
17	Pump down ball to open second sleeve.	Slickwater	0%	3,000
18	Diversion	Crosslinked gelled 15% HCl	30%	12,000
19	Initiate Stimulation	Gelled 15% HCl	30%	4,000
20	Diversion	Crosslinked gelled 15% HCl	30%	15,000
21	Initiate Stimulation	Gelled 15% HCl	30%	5,000
22	Diversion	Crosslinked gelled 15% HCl	30%	18,000
23	Initiate Stimulation	Gelled 15% HCl	30%	6,000
24	Overflush	Slickwater	30%	4,286
25	Flush	Slickwater	30%	14,036

Table 5 Ellenburger – Single Stage Treatment Schedule				
Stage	**Stage Function**	**Fluid Description**	**Percent CO_2**	**Volume, gals**
1	Establish injection rate with cool down	Slickwater	25%	25,000
2	Diversion	Crosslinked gelled 15% HCl	25%	4,500
3	Initiate Stimulation	Gelled 15% HCl	25%	1,500
4	Overflush	Slickwater	25%	2,000
5	Diversion + Ballsealers	Crosslinked gelled 15% HCl	25%	6,000
6	Initiate Stimulation	Gelled 15% HCl	25%	2,000
7	Overflush	Slickwater	25%	2,000
8	Diversion + Ballsealers	Crosslinked gelled 15% HCl	25%	7,500
9	Initiate Stimulation	Gelled 15% HCl	25%	2,500
10	Overflush	Slickwater	25%	2,000
11	Diversion + Ballsealers	Crosslinked gelled 15% HCl	25%	12,000
12	Initiate Stimulation	Gelled 15% HCl	25%	4,000
13	Overflush	Slickwater	25%	2,000
14	Diversion + Ballsealers	Crosslinked gelled 15% HCl	25%	13,500
15	Initiate Stimulation	Gelled 15% HCl	25%	4,500
16	Overflush	Slickwater	25%	2,000
17	Diversion + Ballsealers	Crosslinked gelled 15% HCl	25%	15,000
18	Initiate Stimulation	Gelled 15% HCl	25%	5,000
25	Overflush	Slickwater	25%	2,000
26	Flush	Slickwater	25%	13,831

Table 6 Ellenburger Wells Cumulative Production			
Well	**Cumulative Gas, MMCF**	**Days Producing**	**Treatment**
1	714	502	Single Stage
2	125	411	Single Stage
3	170	206	Single Stage
4	71	114	Single Stage
5	35	61	Single Stage
6	412.8	229	Multi-Stage
7	20.7	81	Multi-Stage
8	N/A	N/A	Multi-Stage
9	N/A	N/A	Multi-Stage

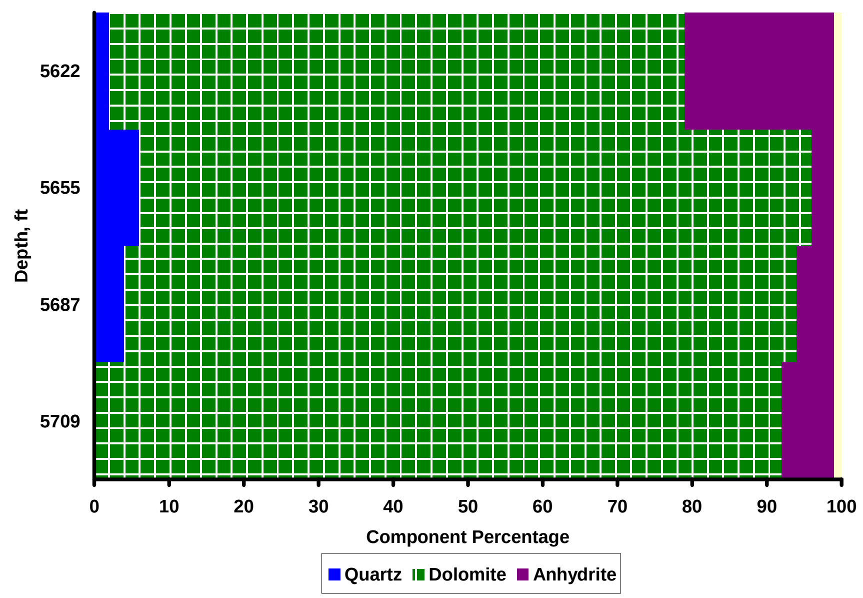

Figure 1 – Variance in Lithology of San Andres

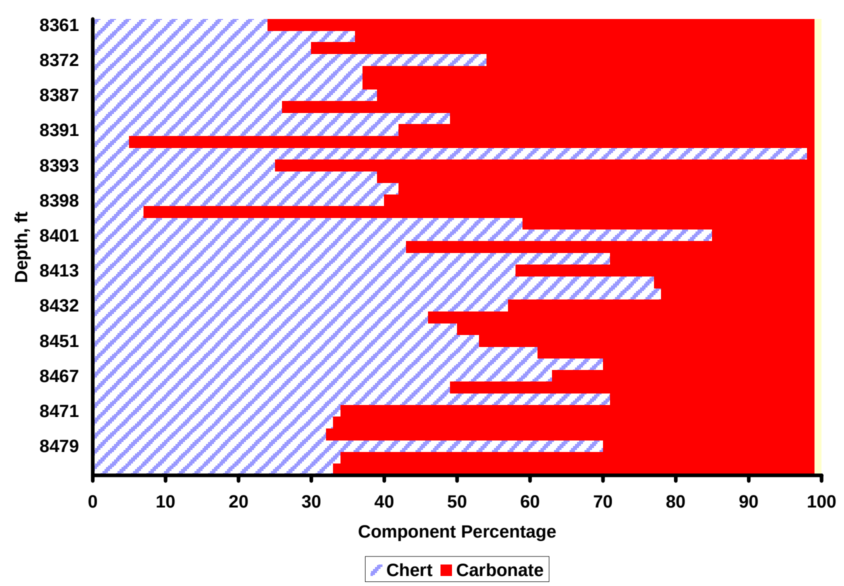

Figure 2 – Variance in Quantity of Chert in Devonian

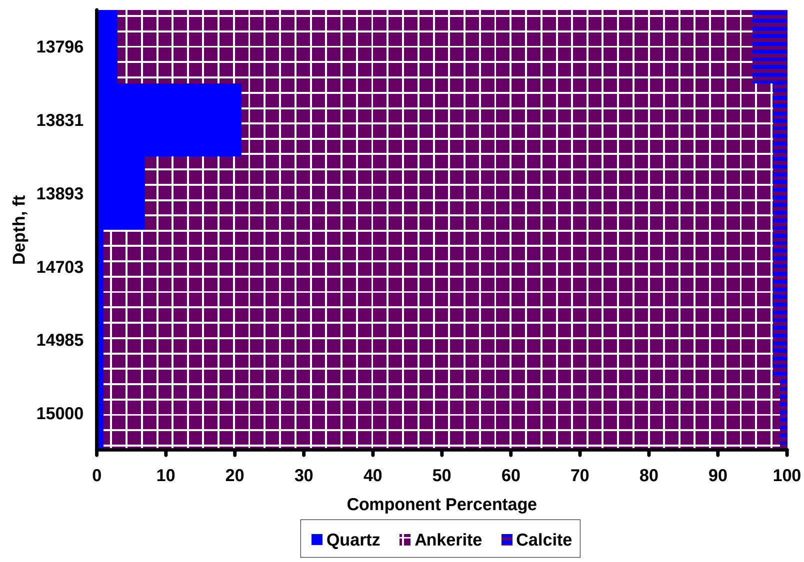

Figure 3 – Variance in quantity of Ankerite in Ellenburger

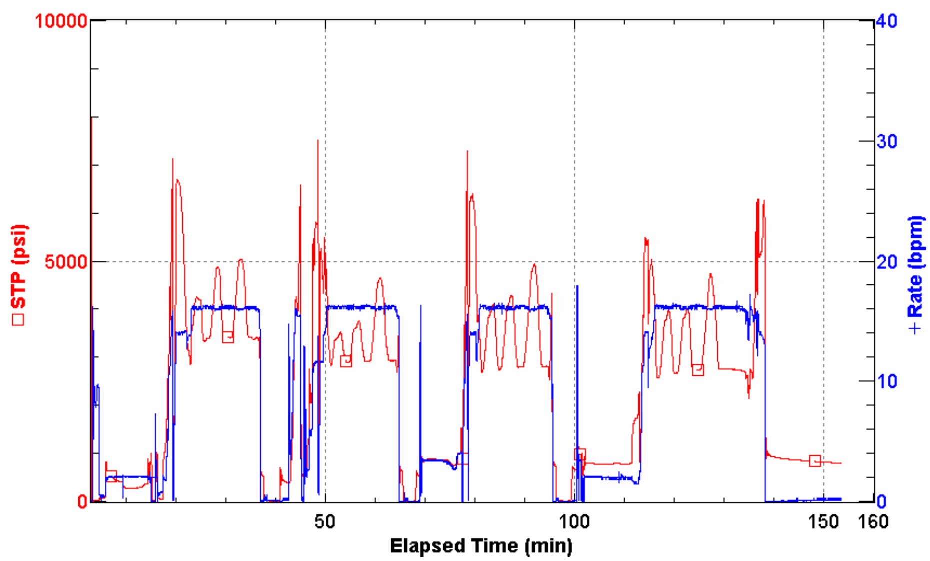

Figure 4 - Plot of Rates and Pressures During Treatment of San Andres Horizontal Well

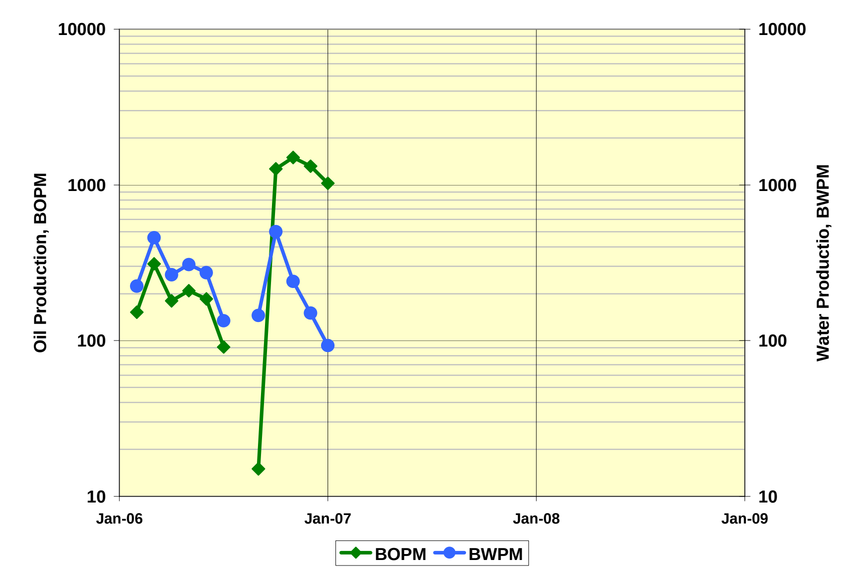

Figure 5 – Production History San Andres Horizontal Well

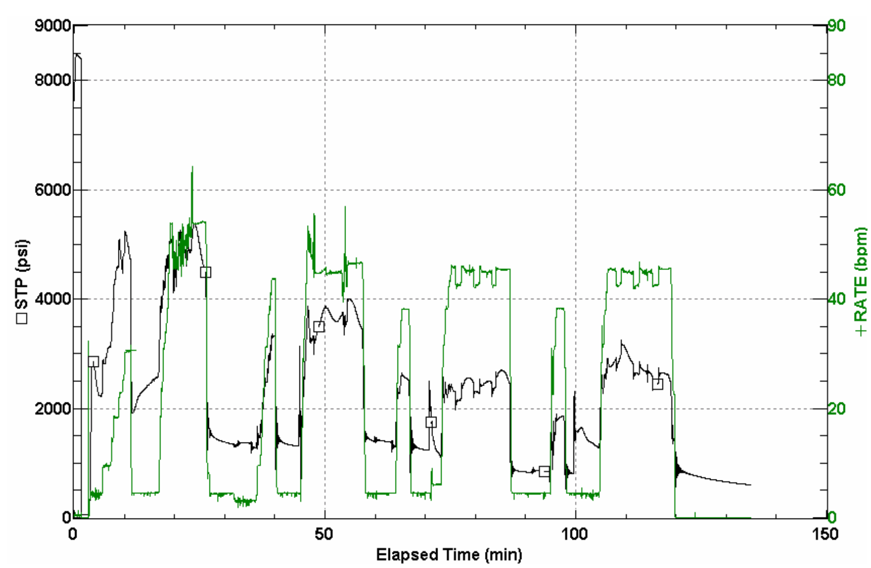

Figure 6 - Plot of Rates and Pressures During Treatment of Devonian Horizontal Well

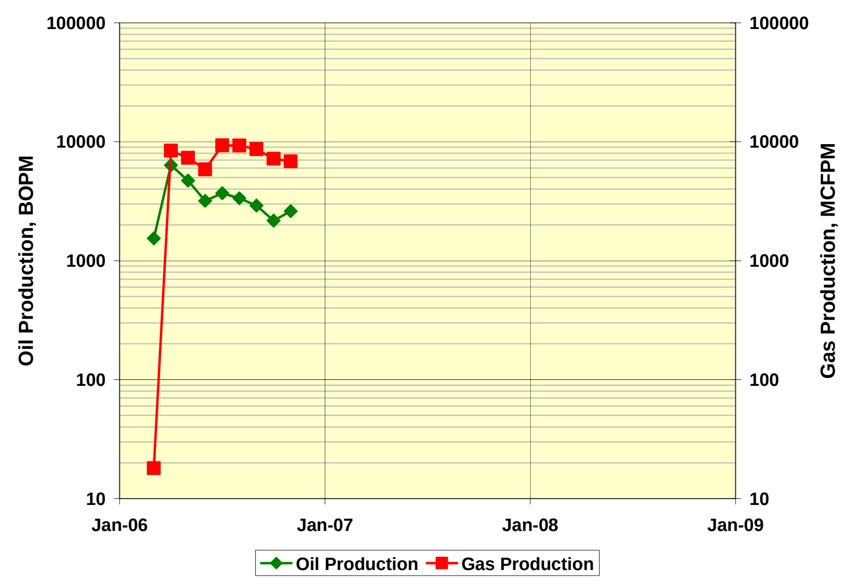

Figure 7 - Production History of Horizontal Devonian Well

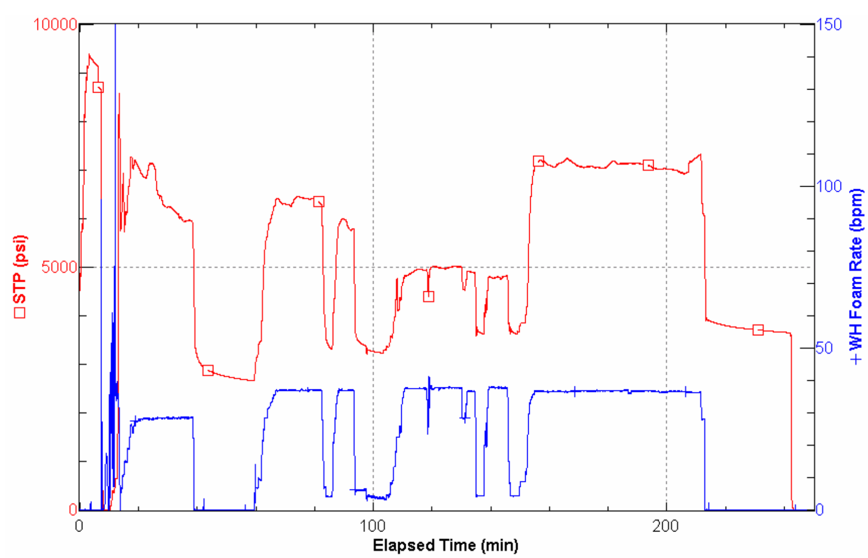

Figure 8 - Plot of Rates and Pressures During a Multi-stage Treatment of an Ellenburger Well

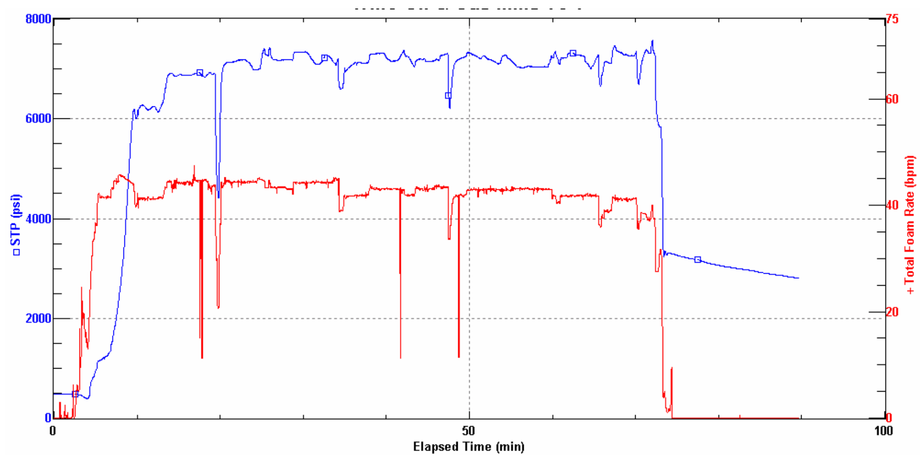

Figure 9 - Plot of Rates and Pressures During a Single-stage Treatment of an Ellenburger Well

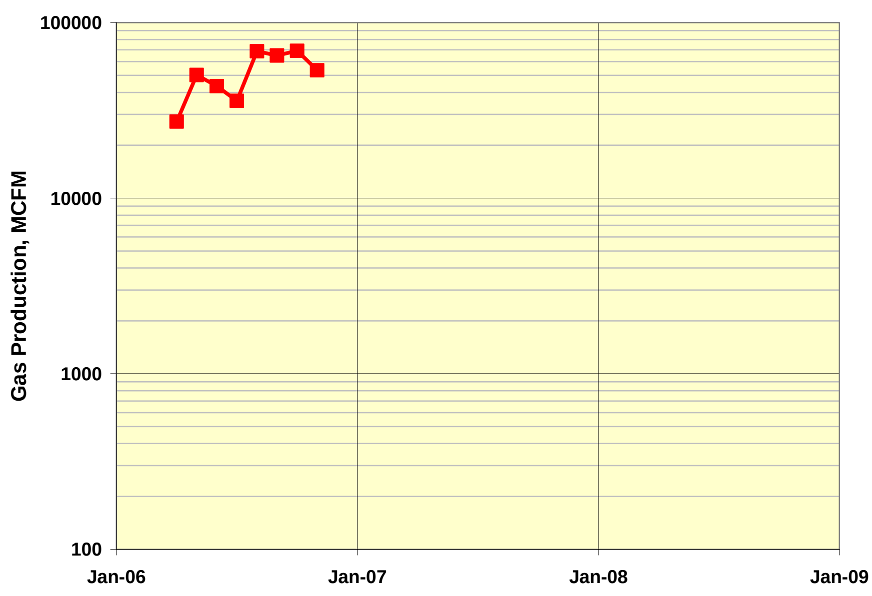

Figure 10 - Production History of Ellenburger Well Treated with a Multi-stage Treatment

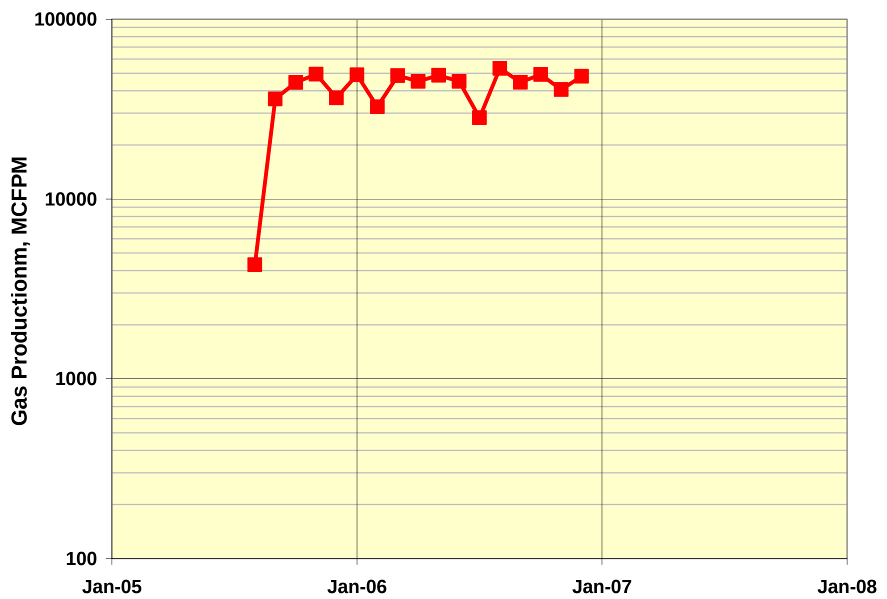

Figure 11 - Production History of Ellenburger Well Treated With a Single-stage Treatment