WILLARD UNIT STIMULATION HISTORY: A CASE STUDY

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Introduction

This paper presents statistics for remedial stimulation work performed at the Willard Unit since 1986. It also discloses how stimulation candidates are chosen, what stimulation fluids are used at present, and how stimulation work is tracked.

The Willard Unit is a San Andres carbon-dioxide flood located in the north-central portion of the Wasson field near Denver City, Texas. The Unit produced under primary from the mid 1930's until the start of waterflood operations in the mid 1960's. Tertiary operations commenced in 1985 with the injection of carbon dioxide into approximately two thirds of the unit which is comprised of 340 producers and 260 injectors.

The San Andres at the Willard Unit is a dolomite found at a depth of about 5100'. Gross pay averages 150', porosity averages 8.5%, and permeability averages 1.5 md. The majority of wells are cased to TD and perforated with 15 to 20 holes. Producers have been sand fractured, and injectors have been either sand fractured or gelled-acid fractured.

Candidate Selection

As shown in Table 1, an alarming number of remedial stimulations since 1986 have been failures: 56% of workovers responded with less than a 5 BOPD increase sustained over a 4 month period. Also, as shown in Table 2, stimulation cost per incremental barrel of oil produced per day has increased dramatically since 1986. Knowing this, in 1993 an extensive effort was made to build a database of past remedial stimulation to help formulate strategies for future stimulation work. Remedial-stimulation histories as well as information regarding well location, initial completion, reservoir quality (phi-h), cumulative production (bbls oil produced per year per phi-h), and current rate (bbls oil per day per phi-h) was compiled in spreadsheet form in a manner that allowed extensive sorting and comparison. An excerpt from the spreadsheet is found in Attachment 1.

The bulk of the stimulation work performed during the years that were analyzed (1986-1992) entailed the use of a calcium-sulfate converter (10% caustic or brand-name converter) followed by hydrochloric acid (15% or 20%, with or without a mutual solvent). In some cases acid was pumped exclusively. In Table 3, the results from each job type are shown. In general, the data indicate that no single job type stands superior to the others. The trend that does develop is evident in Table 1; certain areas of the field respond much better to stimulation than others. We attribute this to variance in damage-mechanism severity and variance in reservoir quality throughout the field. In general, areas with higher water-scaling tendencies and areas of better reservoir quality respond better to stimulation.

Accordingly, if candidate selection is slighted, then results of a stimulation program likely will be disappointing. With this in mind, at Willard we have placed solid emphasis on candidate selection since 1992 and use appropriate data to assess the merits of stimulation for a particular well. Some of the more important issues that we address are as follows:

1. Is cumulative production anomalous to other wells in the area?

2. Is producing rate anomalous to other wells in the area?

3. Has production fallen without reason?

4. Has the well or area responded to remedial stimulation in the past?

5. When was well last stimulated?

6. Are there indications of scale precipitation on downhole or surface equipment?

7. Are scaling tendencies of produced water positive for calcium carbonate and/or calcium sulfate?

8. Where pressure-transient analysis is feasible, is there indication of positive skin?

Stimulation-Fluid Selection

After carefully selecting a stimulation candidate, the process of job design begins. Stimulation fluids are chosen specifically for each well based on which damage mechanisms are suspected using the following guidelines:

Solvent is used when heavy hydrocarbons are encountered on downhole equipment. Heavy hydrocarbons are becoming an increasing problem at Willard as the carbon-dioxide-injection process strips light ends from the crude and leaves heavies behind. Cooling effects from the carbon dioxide have lowered bottom-hole temperature in some producers to as low as 75 degrees F which has exacerbated the problem. Xylene, an aromatic solvent that will dissolve asphaltenes and paraffin, is used when heavy hydrocarbons are encountered. In cases where the hydrocarbons are mixed with scale, xylene emulsified with acid is used as a one-shot fluid. As the carbon-dioxide flood matures it is likely that problems from heavy hydrocarbons will grow, prompting the use of crystal modifiers to inhibit deposition.

Converter is used if calcium-sulfate scale is found on downhole equipment or if water-scaling tendencies are positive for calcium sulfate. Since the start of carbon-dioxide injection, calcium-sulfate scale has become less of a problem because injection water is no longer mixed with make-up water from off lease. But scaling tendencies do show that water from a number of wells can precipitate calcium sulfate at producing temperature and pressure. If calcium sulfate is suspected, a converter is placed across the completion interval at a volume equal to twice the hole volume. Half is then squeezed into the formation and allowed to soak overnight leaving a solid that can be dissolved with follow-up acid treatment.

Acid is used to dissolve calcium-carbonate and iron-sulfide scale which are the predominate damage mechanisms in Willard producers. Since Willard producers have been sand fractured, remedial-acid work is designed to clean perforations and the sand pack with no regard for etching of a fracture face. Fifteen percent hydrochloric acid is considered adequate for this purpose and can be used at costs comparable to smaller volumes of higher-strength acid. Acid volume is designed to fill the sand pack and ranges from 5000 to 8000 gallons. Diversion is achieved with rock salt mixed in gelled brine at concentrations of 1-2 lb/gal. Typically, two stages of block at 1500 lbs/stage are dropped depending on pressures encountered during the job. Additives include a corrosion inhibitor, citric and acetic acid for iron control, a non-emulsifier, and an anti-sludging agent. Concentration of each additive depends on results from tests of acid and crude compatibility. When testing for compatibility, it is important to know how much iron will be encountered during stimulation, what emulsion-break times are adequate, and how much sludge is tolerable if any.

Sand refracs are a viable alternative to converter/acid work, and recently we have refractured several Willard producers with promising results. Candidates typically are wells that were drilled in the early 1970's and fractured originally with small sand volumes at low sand concentrations. Job sizes pumped recently ranged from 50000 to 60000 lbs at final sand concentrations between 8 and 10 ppg. Since fractures at Willard grow radially, we strive to optimize conductivity by pumping higher sand concentrations and lower fluid volumes so that more of the proppant is placed across pay.

One remedial technique that has not worked particularly well at Willard has been increasing shot density. Upon initial completion, most wells were perforated with about fifteen holes over a gross interval of 150', so that ensuing fracture stimulation could be pumped at limited-entry rates (1-2 BPM per hole). Subsequent efforts to increase shot density in 22 wells have not increased production appreciably. This leads one to believe that the limited-entry perforations in wells that have been sand fractured remain in communication even after several years of production.

Most remedial stimulation at Willard has involved producers, but a range of techniques also has been used on injectors. The principle damage mechanism in injectors is iron-sulfide scale and hydrocarbons carried over in injection water. Calcium-carbonate and calcium-sulfate scale also are encountered but not often. Recent work has focused first on removal of fill using coil tubing and then following with an acid clean-up. A blast nozzle that first jets downward is used to get to bottom, after which a sleeve in the nozzle is shifted by dropping a ball which allows side jetting to clean the casing wall. The workover fluid can be water or, when impenetrable scale is encountered, acid. We have been using an acid/toluene blend to jet and dissolve both iron sulfide and hydrocarbons with one stimulation fluid. Injectors with over 75 ft of gross interval covered with fill have been cleaned out successfully and acidized, but resultant increases in injectivity have not been appreciable. We attribute this to the sand fractures which apparently provide a path to the entire pay interval in spite of where injectant leaves the wellbore. Acid and acid/solvent blends that are bullheaded down injection tubing also have proved ineffective in increasing injectivity probably for the same reason.

Post-Job Evaluation

Key to any stimulation program is post-job evaluation and tracking of how a well responds to stimulation. This can be done with a scorecard such as the one shown in Attachment 2. A scorecard should have information that adequately describes treatment type and should track oil production before and after a job. Production after each workover should be zeroed at the producing rate prior to the workover which enables one to construct a graph that is not distorted by workovers spread out over a long period of time. Coupled with evaluating workovers as a group, it is also important to tally the number of successes versus failures, since big increases from just a few wells can mask many failures when stimulation results are viewed in a group plot. Reasons for failures should be quantified and corrective measures should be taken as results become apparent.

Summary

Willard Unit stimulation success has improved measurably. In 1993, we stimulated 19 producers; 17 responded with a sustained increase of at least 5 BOPD, and cost per incremental BOPD was $1550. The improvement can be attributed to a clear focus on candidate selection, proper selection of stimulation fluids, and results-oriented post-job analysis.

Table 1

Section	S	F	% Success
735	3	11	21
736	2	11	15
737	1	5	17
738	4	9	31
762	13	6	68
763	5	9	36
764	2	15	12
765	13	4	76
766	12	3	80
799	16	5	76
800	9	6	60
801	11	5	69
802	2	9	18
700	1	1	50
701	0	8	0
671	0	6	0
672	2	4	33
673	0	2	0
636	0	2	0
635	2	2	50
634	0	2	0
	98	125	44

S = Successful (>5 BOPD sustained)
F = Failure (<5 BOPD sustained)

Table 2

Year	Number of Jobs	Prod Increase BOPD	Prod Increase BOPD/Job	Cost $/BOPD
1986	42	300	[illegible]	2100
1987	74	450	6.1	2600
1988	44	140	[illegible]	[illegible]
1989	18	50	[illegible]	4500
1990	24	70	2.9	5150
1991	9	30	[illegible]	4500
1992	12	45	[illegible]	4000

Table 3

Job Type	Number Of Jobs	Increase BOPD	Inc BOPD/Job	Successes	% Success
1	145	779	5.4	65	45
2	22	107	4.9	9	41
3	16	58	3.6	[illegible]	44
4	12	38	3.2	5	42
5	28	113	4.0	12	43

Key:

1	550 gallons converter, 6000 gallons 15% NEFE HCL
2	550 gallons converter, 6000 gallons 15% NEFE HCL w/mutual solvent
3	3000 gallons 10% caustic, 6000 gallons 20% NEFE HCl
4	3000 gallons 10% caustic, 6000 gallons 20% NEFE HCl w/mutual solvent
5	6000 gallons 15% NEFE HCl

Attachment 1

Well	Section	Row	ORIGINAL PERFS Date	Interval	# Holes	REMEDIAL PERFS Date	Interval	# Holes	ORIGINAL FRAC (gal)	(lbs)	(mesh)	REMEDIAL FRAC Date	(gal)	(lbs)	(mesh)	REMEDIAL STIMULATION Date	Type	+ BOPD	+ BWPD	Duration (mos)	REMEDIAL STIMULATION Date	Type	+ BOPD	+ BWPD	Duration (mos)
1A	7W	2	1973	4957-5124	17				23 000	44 000	20-40 10-20					Apr 87	4 6 9	30	150	12+	Jun 93	3 4 6 9			
1B	7W	1	1992	4937-5157	18																				
1C	7W	2	1982	4952-5135	18	Feb 88	4957-5123	19	38 000	53 800	100 20-40 10-20					Nov 86	2 4 6	10	170	12+	Feb 88	1 4 6 9 10	10	160	12+
1D	7W	[illegible]	1982	4950-5161	23							Jul 86	26 376	49 200	10-20	Jul 86	4 6 8	15	200	12+	Sep 88	4 6 9	6	10	8
2A	7W	[illegible]	1973	4953-5133	17	Apr 79	4841-4912	31	29 000	45 500	20-40 10-20	Apr 79	17 500	18 000	20-40	Apr 79	6 8	5	25	2	Oct 87	4 6 9	5	50	2
[illegible]	7W	1	1992	4939-5155	19				160 000	46 500	[illegible]														
2B	7W	[illegible]	1979	4912-5060	29				30 000	13 500	100										Jun 86	4 6 9	0	75	
3A	7W	[illegible]	1973	4953-5110	17				29 000	55 500	20-40 10-20										Sep 87	4 6 9	3	100	2
3B	7W	[illegible]	1979	4913-4973	17	Feb 86	4977-5095	14	4 000	6000	100	Feb 86	17 700	33 200	20-40 10-20	Mar 83	6 11	0	0		Feb 86	6 8 10	5	90	12+
4A	7W	2	1973	4924-5137	17	Apr 79	4804-4868	33	29 000	55 500	20-40 10-20	Apr 79	17 500	12 000	20-40	Jul 80	6	5	50	12+	Jul 87	4 6 9	2	150	12+
4B	8W	[illegible]	1975	4920-5159	18				29 000	55 500	20-40 10-20										Nov 90	3 5 7 9	12	50	12+
5A	8W	[illegible]	1969	4945-5160	13				30 000	60 000	20-40										Mar 87	4 6 9	6	100	1
5B*	8W	[illegible]	1979	4953-5035	24	Oct 86	5069-5131	9	2 000	2 000	100	Oct 86	27 800	38 700	20-40						Oct 86	6 8 10	8	250	12+
5C	8W	1	1980	4958-5133	16											Mar 88	4 6	10	100	10	Jun 91	5 6	12	60	12+
6A	8W	[illegible]	1969	4972-5164	13				30 000	55 000	20-40										Nov 88	4 6 9	0	75	
6B	8W	[illegible]	1976	4941-5137	15				19 000	35 000	20-40 10-20										Jul 93	3 4 6 9			
[illegible]	8W	1	1940	4215-5200	OH							Feb 69	12 900	15 000	10-20						May 87	1 4 6 9	18	70	12+
7A	8W	[illegible]	1969	4997-5150	15				30 000	50 000	20-40					May 87	4 6 9	0	0		Mar 90	5 7 3 9	10	50	3
7B	8W	[illegible]	1969	4993-5054	11	Feb 86	5032-5141	12	5 000	6 000	100	Feb 86	18 800	39 000	20-40 10-20	Feb 86	1 6 8 10	0	120		Jul 89	4 6 9	10	75	12+
8	8W	1	1940	4047-5192	OH	Feb 76	4932-5148	15				Feb 76	19 000	30 650	20-40 10-20	Feb 76	6 8 10 11				Jun 88	1 4 6 3 9			
9A	8W	[illegible]	1969	4993-5166	13				30 000	52 500	20-40										Dec 87	4 6 9	0	0	
9B	8W	2	1975	4983-5143	17	Feb 79	4854-4939	33	19 000	35 000	20-40 10-20	Feb 79	11 300	18 000	20-40	Feb 79	6 8 10	10	15	2	Oct 87	4 6 9	3	25	5

Key to Stimulation Type
1 [illegible]
2 [illegible]
3 [illegible]
4 [illegible]
5 [illegible]
6 15% [illegible]
7 20% [illegible]
8 [illegible]
9 [illegible]
10 [illegible]
11 Misc. [illegible]

Attachment 2

Treatment Type
- P - Add Perforations
- S - Solvent
- C - Converter
- D - Dissolver
- A - Acid
- FS - Sand Frac
- FA - Acid Frac

Well Type
- PB - Producer/Beam
- PF - Producer/Flowing
- PE - Producer/ESP
- IW - Injector/Water
- IC - Injcetor/CO2

														BOPD By Month - Time Zero															
Treatment Type	**Well No.**	**Well Type**	**Completion Date**	**Cost, $M**	**-12**	**-11**	**-10**	**-9**	**-8**	**-7**	**-6**	**-5**	**-4**	**-3**	**-2**	**-1**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
SCA	1A	PB	07/01/93	12 9	20	25	19	19	18	19	19	18	19	19	19	18	18	29	25	25	24	23	23	25	24	26	24	26	25
SCA	6B	PB	07/10/93	19 7	13	22	15	16	17	16	17	14	13	14	15	11	15	28	20	20	25	28	32	30	29	31	30	30	31
A	12A	PB	09/03/93	12.9	38	42	41	39	40	40	42	44	55	55	56	51	53	71	80	66	55	69	65	63	68	72	56	51	45
CA	13C	PB	10/15/93	10 9	22	21	18	19	18	18	19	22	21	20	20	24	25	52	51	55	44	28	26	22	22	23	23	21	22
PA	14A	PB	08/16/93	10.0	17	22	21	20	20	20	22	22	22	21	22	26	20	31	30	33	35	32	30	28	26	19	21	20	19
SCA	26C	PB	07/15/93	13 7	6	10	12	12	12	16	17	15	16	17	19	16	15	30	27	28	26	28	28	24	21	16	17	16	13
A	32C	PB	09/02/93	13.1	12	13	10	10	10	14	8	11	9	9	9	15	20	35	30	28	28	26	23	32	35	33	31	32	30
PSF	38A	PB	07/29/93	35.0	29	29	28	29	28	28	28	16	17	15	11	15	14	32	23	21	21	15	13	15	14	14	15	14	13
A	41D	PB	05/25/93	11.0	10	10	16	15	15	13	11	12	12	11	10	10	10	10	4	4	4	5	5	10	12	11	10	11	12
SCA	43A	PB	07/19/93	15.0	16	17	18	12	9	9	9	11	11	14	12	14	13	19	21	23	25	24	24	25	26	27	25	32	32
SCA	61A	PB	07/29/93	11.2	25	27	23	29	25	24	25	23	22	23	25	27	28	34	33	32	34	34	37	36	36	36	34	36	33
PSF	71A	PB	11/06/93	35 0	9	8	6	5	10	11	11	12	10	9	13	12	11	30	32	19	20	22	11	15	15	13	13	11	12
PSF	72A	PB	09/17/93	37 1	6	6	5	6	6	6	2	2	2	7	7	7	7	35	31	28	25	25	20	23	19	21	23	23	25
PA	73C	PB	08/10/93	10.0	21	21	18	16	16	17	17	18	18	14	19	19	18	37	35	31	25	24	24	24	25	24	30	29	30
A	74A	PB	06/06/93	8 9	13	13	11	11	11	11	12	13	9	10	10	9	9	25	20	10	10	10	10	10	10	10	10	10	10
SCA	78A	PB	06/11/93	12.3	14	13	14	15	18	15	13	14	14	14	16	14	14	25	23	22	21	21	21	21	24	24	24	24	24
CA	105	PB	10/10/93	13.0	10	10	9	9	9	10	10	8	9	8	9	8	8	23	17	17	15	22	19	18	16	19	18	16	17
CA	107B	PB	08/05/93	14 5	14	18	16	20	15	16	18	18	15	17	13	10	6	9	10	10	11	9	6	8	6	5	6	7	5
PA	133B	PB	07/06/93	12.0	5	5	6	6	5	3	3	3	2	2	2	2	2	10	11	6	9	12	10	14	10	12	6	6	10
				308	300	332	307	307	303	304	302	295	297	299	307	309	305	566	523	478	457	457	427	443	438	436	416	415	408