GAS WELL STIMULATION IN THE MORROW SANDSTONE OF S. E. NEW MEXICO

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INTRODUCTION

Successful stimulation of the Morrow has long eluded both operator and service company. Throughout the years, certain treatment procedures or treatment fluids have been promoted as the answer to the problem of stimulating the Morrow. Almost every type of stimulation fluid has been used in treating the Morrow and many have been successful at one time or another. By 1966, water-base fluids were most universally accepted as the fracturing fluid to use, mainly because of the uniformly poor performance of oil-base fracturing fluids in the Morrow. In late 1966 and early 1967, several treatments were done using a gelled water-base frac fluid made with dilute acid and alcohol. The results from these treatments were generally good; but because of the cost at the time, operators turned to gelled brine systems. These were followed by ultra-viscous gelled water fracturing fluids and later by volatile fracturing fluid treatments. Now a new version of the gelled dilute acid, incorporating new additives and treatment procedures used in other Pennsylvanian Sandstones, is being used with good success for treating the Morrow Sandstone in southeast New Mexico.

While some operators were evaluating the various fracturing treatments, other operators completed their wells using only an acidizing treatment with an alcoholic hydrochloric-hydrofluoric acid mixture to remove or bypass wellbore damage. In general, this acidizing technique has been successful in increasing productivity. This technique can be used as an alternative to fracturing in wells that have good permeability. Unfortunately, the low productivity of most Morrow wells limits the applicability of acidizing as the sole stimulation treatment. Due to the low permeability of the formation, stimulation is best accomplished by deep penetrating fractures.

MORROW FORMATION CHARACTERISTICS

The Morrow produces in several fields in southeastern New Mexico, mainly in southern Eddy and Lea Counties (see map, Fig. 1) with most of the production in Eddy County. The producing depth ranges from 9200-14,800 ft. The Morrow is a hard, tight quartzite sandstone with permeability varying from 0.3 md to 462 md, with average permeability usually less than 5 md. The porosity varies from 5-15%, averaging about 10%. Bottomhole static temperatures vary from 135°F to 210°F, depending upon the location and depth of the well. There is a wide variation in the frac gradient of the Morrow, usually from 0.65 psi/ft to over 0.9 psi/ft. This variance in frac gradients sometimes appears in direct offset wells, making the treating pressure difficult to predict. The pay interval may be one or more zones, 10 ft to 25 ft thick over an interval of 200 ft. Often times, the zones are not continuous between wells.

Several good Morrow wells have been drilled that have potentialled in excess of 15 MMCFD. Many of these good wells are natural completions that did not require any stimulation. Many more Morrow wells would produce at rates less than 500 MCFD if it were not for some stimulation treatment. This paper is concerned with the wells in this latter category.

The Morrow is a quartzitic sandstone that is gray, massive, hard and fine to coarse grained. The outstanding characteristics of the rock are the great variations in the diameter of the quartz sand grains and the tight interlocking of the grains.[1] The X-ray diffraction analysis shows the intergranular cementing material to consist primarily of kaolinite, dolomite, calcite and small

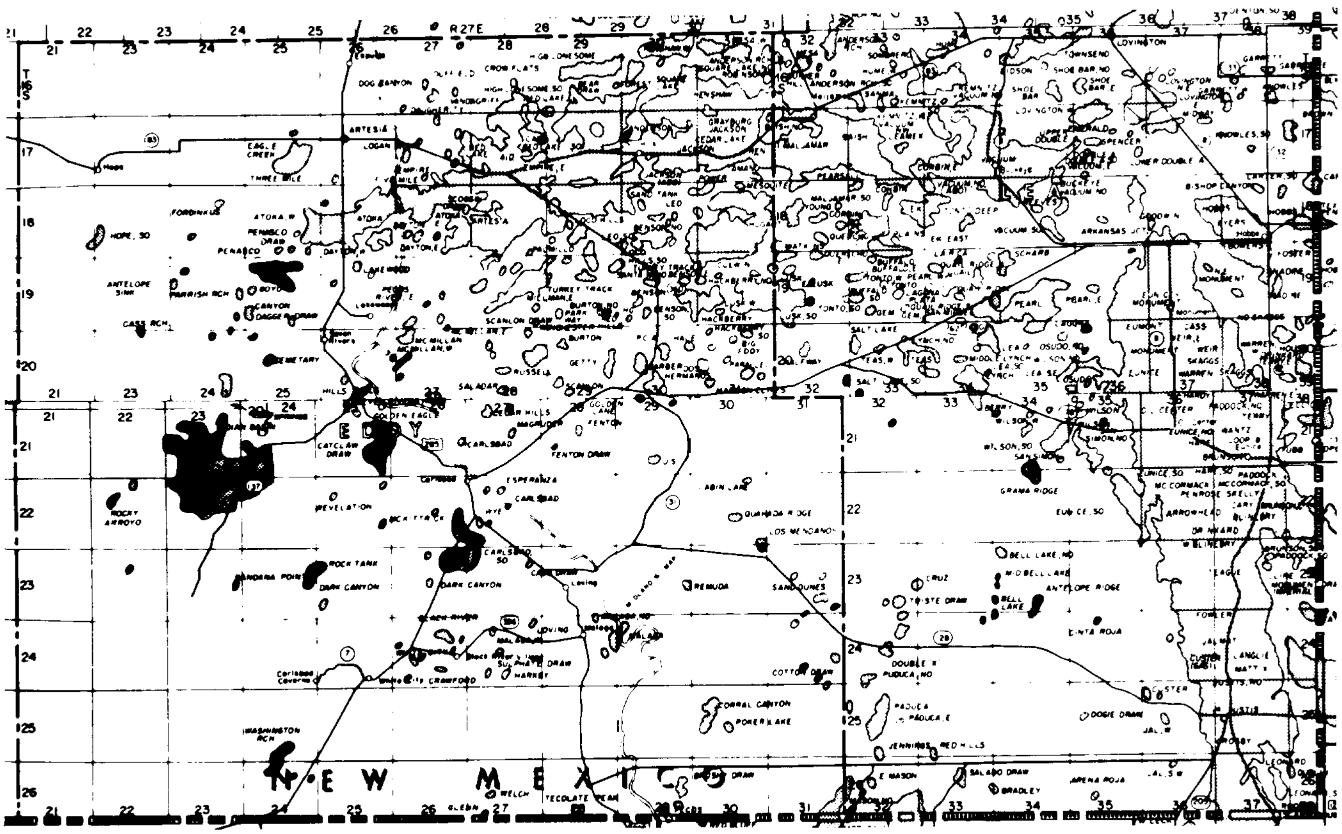

FIG. 1—MORROW SANDSTONE PRODUCTION, SOUTHEAST NEW MEXICO (MAP REPRINTED THROUGH THE COURTESY OF MIDLAND MAP CO.)

amounts of montmorillonite, illite, siderite and anhydrite. The overall percentage of the clay materials is low; however, as they lie between the quartz grains, they are most likely to be contacted by invading water. Table 1 lists the results of X-ray diffraction analyses on several Morrow cores. The Morrow has low solubility in 15% hydrochloric acid (usually less than 10%) and slightly higher solubility in hydrochloric-hydrofluoric acid mixtures (10-25%). The higher solubilities are due to the presence of calcite, dolomite or siderite.

TREATMENT PROBLEMS

Many of the problems in stimulating the Morrow are due to the properties of the rock and are common to other low permeability Pennsylvanian Sandstone formations. These problems include low permeability, clay particle migration, iron, scale, fluid retention and high frac gradients. All of these factors must be considered when designing a treatment for the Morrow. In addition to the formation problems, there are the usual mechanical problems to consider. These include type of packer used, tubing size, casing size, pressure limitations of tubular goods and wellhead equipment, size of perforations and perforating pattern. Most of the formation problems can be controlled by the proper selection of additives used in the treatment fluids. These additives will be discussed later.

COMPLETION PROCEDURES

Most Morrow wells are drilled with the anticipation (or hope) that the well will be a good natural producer and that little or no stimulation treatment will be necessary. With this approach, the operator will usually set a permanent packer, run tubing and perforate with a differential pressure toward the wellbore. If the well will produce at a commercial rate, all is fine. All is still fine if only a small acid treatment is required to break past the damage area around the wellbore. This tubing and permanent packer completion is especially advantageous when producing the well. Problems arise when additional stimulation is required, particularly when a fracturing treatment is necessary. The injection rate down tubing at the depths encountered is limited.

TABLE 1—X-RAY DIFFRACTION ANALYSIS OF THE MORROW FORMATION

X-Ray Diffraction Analysis

Well No.	Sample Depth (feet)	Major (25-100%)	Minor (10-30%)	Low (less than 15%)
1	11,400 - 10	Calcite	Quartz	Dolomite, Kaolinite, Illite, Halite
1	11,420 - 30	Calcite, Quartz	--	Dolomite, Kaolinite, Illite, Halite
1	11,460 - 70	Quartz	Calcite, Illite	Dolomite, Halite, Kaolinite, Pyrite, Siderite
1	11,638	Quartz	--	Dolomite, Calcite, Kaolinite, Halite, Siderite
1	11,660 - 70	Quartz	Illite	Dolomite, Calcite, Kaolinite, Pyrite, Halite, Siderite
1	11,700 - 10	Quartz	Dolomite, Calcite	Kaolinite, Illite, Montmorillonite, Halite, Siderite
1	11,777	Quartz	Calcite	Dolomite, Kaolinite, Illite, Halite, Montmorillonite, Pyrite
1	11,840 - 45	Quartz	Halite, Non-crystalline	Dolomite, Calcite, Illite, Kaolinite, Montmorillonite
1	11,900 - 12,000	Quartz	Calcite	Dolomite, Kaolinite, Illite, Halite, Montmorillonite
2	11,093	Quartz	--	Kaolinite, Illite, Feldspars
2	11,111	Quartz	Kaolinite, Dolomite	Halite, Siderite
2	11,190	Quartz	--	Kaolinite, Illite, Montmorillonite, Feldspars
2	11,196	Quartz	Siderite	Kaolinite, Dolomite, Feldspars
3	12,575	Quartz	Siderite	--
4	10,362	Kaolinite	Anhydrite	Montmorillonite
5	10,310	Kaolinite	Anhydrite	Montmorillonite
6	9,052 - 60	Kaolinite	Anhydrite	Montmorillonite
7	9,094	Kaolinite	Anhydrite, Dolomite	Montmorillonite

Figure 2 is a graph of the maximum injection rates possible at a maximum allowable surface treating pressure of 9000 psi for various depths and different frac gradients. The injection rate down 2-3/8 in. OD, 4.7 lb/ft tubing is usually between 8 BPM and 15 BPM. These low injection rates decrease the fracture penetration of the reservoir and the effectiveness of the treatment. Fortunately, in some cases, the limited vertical extent of the pay zone will allow good penetration even at the low injection rates. Staged treatments are necessary to treat multiple zones or zones whose gross interval is in excess of 40 ft.

ACIDIZING PROCEDURES

If, after perforating, the well does not produce satisfactorily, an acidizing treatment will be required. The purpose of the acidizing treatment may be either to remove or bypass permeability

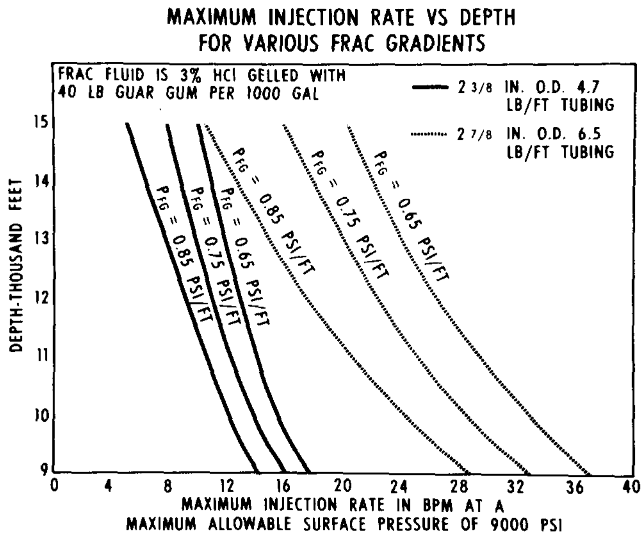

FIG. 2

damage around the wellbore or to ensure that the perforations are open and the well is ready for a fracturing treatment. Each purpose uses a different acidizing technique and acid systems to accomplish its task.

For successful removal or bypassing of permeability damage, the acid used must be capable of removing the damage and dissolving portions of the rock. This acid will be a mixture of hydrochloric and hydrofluoric acid, usually a 12% hydrochloric and 3% hydrofluoric mixture. Special additives may be added to the acid to control iron and/or scale problems. Since this acid treatment may be all that is required to stimulate the well, a clay stabilization treatment can be applied at the same time, which will protect the well from clay migration problems later.

The recommended treatment procedure is as follows:

1. Inject 30 gal. of 15% hydrochloric acid per foot of pay.
2. Inject 100 gal. of hydrochloric-hydrofluoric acid per foot of pay.
3. Inject 250 gal. 5% hydrochloric acid spacer.
4. Inject 100 gal. of 5% hydrochloric acid plus 3% clay stabilizer per foot of pay.
5. Flush to perforations with 2% potassium chloride or calcium chloride water.
6. Shut well in for two hours, then recover load.

If the limit of permeability damage is not more than three to five feet from the wellbore, the acidizing could be done at pressures below fracturing pressure as in the matrix acidizing technique. For cases where the damaged area is more extensive, or unknown, the acidizing would best be done above fracture pressure, but at low injection rates to keep the penetration closer to the wellbore. What is required here is enough penetration to get well beyond the damage zone but not so far that the acid is spread over such a large fracture area that it does little good. Low injection rates, 2-4 BPM, with the volumes of acid as above, will accomplish this goal. The acid should be recovered as soon as practical after the treatment. For multiple zones, the acid treatment can be staged with ball sealers. Matched density ball sealers should be used if the matrix acidizing technique is used.

The second type of initial treatment is acidizing to open all perforations and prepare the well for a fracturing treatment. The fracturing treatment may not be necessary if the well responds to the treatment with a satisfactory producing rate. Since this treatment is used on wells of apparent low permeability or poor DST results, the production increase may not be commercial but may be enough to evaluate the well. The acid used in this treatment may be 7-1/2 to 15% hydrochloric acid with special surfactants to ensure rapid clean-up. Since there is little advantage with hydrochloric-hydrofluoric acid mixtures in this type of application, regular hydrochloric acid is generally used because of its lower cost. Ball sealers are used to divert the acid from one perforation to another to ensure that all perforations are open. Injection rates should be as high as economically practical, preferably 4-6 BPM, to improve ball seating efficiency. Usually 1-2 bbl of acid per perforation and 50-100% excess ball sealers are used in this treatment. Ball sealers may be dropped singly or several at a time, depending upon the perforating pattern. The spent acid should be recovered as soon as possible after the treatment. Here, the use of nitrogen or carbon dioxide is particularly useful in promoting more rapid and complete clean-up.

ACIDIZING ADDITIVES

As stated previously, the potential problems in treating the Morrow are low permeability, clay particle migration, iron, scale, fluid retention and high frac gradients. Acidizing will help the problem of low permeability, and the immediate shut-in pressure after the acid treatment can be used to calculate the frac gradient. Acid additives will be required to control the other problems.

Clay particle migration can be prevented by the use of hydrolyzable metal compounds.[2] While acid itself causes minimal disturbance of the clay particles, the acid reaction can release fines which may become free to migrate and cause formation plugging. Special mutual solvents can be added to the acid formulation to help maintain these particles in suspension and reduce the effects of their migration. Another additive to control clay migration is a surfactant that functions by coating the clay particles with a film that repels water. Calcium chloride water or potassium chloride should be used as the flush water to minimize formation damage if the flush should contact the formation. There have been several instances reported where a well's productivity was severely reduced by killing the well with water containing a high concentration of sodium chloride; also published papers[4,5] have shown that sodium chloride brines can render a formation sensitive to fresh water. It can be concluded, then, that it is poor practice to use saturated sodium chloride brine in formations containing clay materials.

As seen in Table 1, many of the Morrow cores contain siderite (iron carbonate) which will be dissolved by the acid. Iron will remain in solution if the spent acid solution is maintained at a pH of 2 or lower. Acetic acid may be added to help maintain this low pH or EDTA salts may be added to stabilize greater concentrations of iron in solution over a wider pH range.[3] The selection of this additive will be governed by the overall compatibility of other additives.

Some scale problems have developed in a few wells after acidizing. The scale may be caused by some anhydrite in the formation or may be due to the loss of potash brine to the formation during drilling or completion of the well. This potash brine is commonly used in southeastern New Mexico in drilling and workover operations. Analysis of the brine shows that it is composed mostly of sulfate. The use of this brine in the Morrow could leave the formation highly sensitive to fresh water and could cause some scale problems if mixed with spent acid. A liquid scale inhibitor is available as an acid additive to prevent this scale deposition.

Fluid retention is always a severe problem in low permeability gas formations.[6] In the past, alcohol was used to lower the surface tension of the treatment fluid so that the fluid recovery would be increased. The present scarcity of methanol—isopropanol is practically impossible to obtain—has led to the development of a surfactant that lowers the surface tension of acid far below the values obtained with alcohol. This material is low in cost and readily available.

Most of the above additives are also applicable to fracturing fluids to solve some of the same problems encountered in fracturing as in acidizing. Each additive's compatibility must be assured before it is mixed with the treatment solution. No additive should be used if it is not needed. However, two of the problems will exist in most Morrow wells: clay particle migration and iron. Unless there are indications to the contrary, additives should be used with the acid formulations to stabilize the clay particles and to prevent secondary iron deposition.

FRACTURING TREATMENTS

Dilute hydrochloric acid (1-5%) is the base fluid most generally used in fracturing the Morrow. Other "safe" fluids would be 1-3% potassium chloride water or 1-2% calcium chloride water. Water with a high concentration of sodium chloride should be avoided because of possible changes in the rock's sensitivity to water. The use of dilute acid, potassium chloride water or calcium chloride water will help avoid problems with clay particle migration. Further help may be obtained by using hydrolyzable metal compounds in the pad volume ahead of each stage of the fracturing treatment. Another aid is a surfactant that controls clay by coating the clay particles with a film that is repellant to water. If the fracturing fluid used is weak acid, an iron stabilizer should be used in the fluid to prevent secondary deposition of iron. The same additives used to control iron in acid treatments may be used in the dilute acid fracturing fluid. Iron problems may be avoided by the use of potassium chloride or calcium chloride water rather than using an acid-base fracturing fluid.

Most fracturing treatments of the Morrow are done down tubing, either 2-3/8 in. OD or 2-7/8 in. OD tubing, which limits the injection rate. The injection rates for most Morrow fracturing treatments are low, usually 10-15 BPM. These low rates will necessitate the use of a more viscous frac fluid than is commonly used in the Permian Basin. Usually 40-60 lb of guar gum or cellulose gelling agent is used per 1000 gal. of fracturing fluid. The higher viscosity is required in order to obtain adequate fracture widths at low injection rates. A fluid loss additive is also generally used—Adomite Aqua or silica flour with guar gum gelling agent and Adomite Aqua with the cellulose gelling agent. Some treatments have been done without the fluid loss additive but generally one is used as insurance against screenouts in the deeper wells. Other additives include buffers and breakers to provide rapid viscosity reduction after the treatment.

Another important method commonly used to reduce the fluid retention by the formation is to incorporate nitrogen or carbon dioxide in the frac fluid. The nitrogen and carbon dioxide limit the fluid retention by reducing the residence time of the frac fluid in the formation. The cost of the nitrogen or carbon dioxide is often defrayed by the rapid clean-up without having to swab the well. Both nitrogen and carbon dioxide have been successfully used in Morrow fracturing treatments and both seem to perform equally well. The availability of nitrogen out of Carlsbad, New Mexico, gives it an edge over carbon dioxide which must be delivered from Solano, New Mexico. For larger treatments, in excess of 30,000 gal., the carbon dioxide will be somewhat less expensive. Experience has shown that 650 SCF/bbl of fracturing fluid is usually enough to ensure rapid clean-up.

The disadvantage of nitrogen is that it is pumped as a gas and therefore reduces the hydrostatic head of the frac fluid, increasing the surface treating pressure. Carbon dioxide is pumped as a liquid at approximately -18°F. The effect of this cold liquid should be considered when designing treatments for the deeper wells.

Flowback of the fracturing fluids should be started as soon as practical after the fracturing treatment is completed. Shut-in times longer than two to four hours are usually of little benefit and may even be detrimental in some cases, particularly in wells with lower reservoir pressure. If the nitrogen gas or carbon dioxide gas is allowed to dissipate, some of its potential energy will be lost resulting in slower clean-up of the well. The actual flowback of the well is difficult to prescribe as many wells will flow back differently. Flowback on a choke size of 12/64 in. to 16/64 in. will usually be a good starting point. From then on, the tubing pressure can be observed and choke adjustments can be made to ensure a good steady flow rate.

Return of the frac sand has generally not been a problem where the flow rate has been properly controlled. After a few hours, the frac fluid viscosity is reduced due to the breakers in the gel system as well as the viscosity reduction at reservoir temperatures. This lower viscosity coupled with a slower fluid movement does not disturb the sand pack in the fracture enough to cause much sand movement to the wellbore.

TABLE 2

Treatment Volume (gals)	Frac Volume (cu ft)	Frac Length (ft)	Frac Width (inches)	C_{VW} Used Ft/Sort (min)
Minimum pad for prop (diameter at wellbore = 0.083)				
1142.	22.	133.	0.0660	7.230 E-3
5000.	135.	394.	0.1369	4.760 E-3
10000.	296.	630.	0.1878	4.098 E-3
15000.	461.	821.	0.224	3.805 E-3
20000.	627.	988.	0.2541	3.630 E-3
25000.	794.	1137.	0.2794	3.511 E-3
30000.	961.	1274.	0.3016	3.423 E-3
35000.	1127.	1402.	0.3216	3.354 E-3
40000.	1293.	1522.	0.3399	3.299 E-3
45000.	1459.	1635.	0.3567	3.253 E-3
50000.	1624.	1743.	0.3724	3.215 E-3

TABLE 3

Frac Height = 15 feet Net Height = 10 feet

Treatment Volume (gals)	Frac Volume (cu ft)	Frac Length (ft)	Frac Width (inches)	C_{VW} Used Ft/Sort (min)
Minimum pad for Prop (diameter at wellbore = 0.083)				
3254.	52.	158.	0.0660	5.302 E-3
5000.	87.	215.	0.0813	4.760 E-3
10000.	194.	346.	0.1121	4.098 E-3
15000.	305.	453.	0.1343	3.805 E-3
20000.	418.	543.	0.1526	3.630 E-3
25000.	530.	631.	0.1679	3.511 E-3
30000.	642.	708.	0.1813	3.423 E-3
35000.	754.	779.	0.1934	3.354 E-3
40000.	865.	846.	0.2045	3.299 E-3
45000.	976.	910.	0.2146	3.253 E-3
50000.	1037.	970.	0.2241	3.215 E-3

All of these additives serve a useful purpose in tailoring a frac fluid to meet the special problems of the Morrow. Care must be taken to ensure that all of the additives used in making the frac fluid are compatible. Tables 2, 3 and 4 are the results obtained by computer runs used to calculate the fracture geometry for various fracture heights in the Morrow. The fracture height in a particular well would depend on the zonal development in the well. The information in Tables 2, 3 and 4 would be applicable only for wells with one of these fracture heights, but the tables will give some idea as to the penetration achieved with various treatment volumes. If more than one zone is present, the treatment will require staging, using either ball sealers or a solid diverting agent to divert the treatment from one zone to another. All data except fracture height and net pay was the same for all three tables. The data used is as follows:

Formation = Morrow Sandstone	Young's Modulus = 12 x 10^6 psi
Depth = 11,000 ft	Permeability = 1.0 md
Injection Rate = 12.5 BPM	Porosity = 10%
BHP = 4000 psi	Max. Treating Pressure = 9000 psi
BHT = 175°F	Frac Gradient = 0.75 psi/ft

The propping agents normally used in the Morrow are 20/40 mesh sand or a mixture of 20/40 sand and 20/40 or 12/20 glass beads. The mixtures vary from 70-80% 20/40 sand and 30-20% glass beads. If 20/20 glass beads are used, the treatment must be carefully designed to provide adequate fracture width. The higher strength of the glass beads and the resultant increased fracture conductivity make these mixtures especially attractive for use in the deeper Morrow wells. The sand in the mixture serves as a spacer to extend the glass beads and reduce treatment costs.

TABLE 4

Frac Height = 30 feet Net Height = 25 feet

Treatment Volume (gals)	Frac Volume (cu ft)	Frac Length (ft)	Frac Width (inches)	C_{VW} Used Ft/Sort (min)
Minimum pad for prop (diameter at wellbore = 0.083)				
7442.	98.	178.	0.0660	4.353 E-3
5000.	62.	135.	0.0547	4.760 E-3
10000.	138.	219.	0.0757	4.098 E-3
15000.	217.	287.	0.0908	3.805 E-3
20000.	297.	346.	0.1031	3.630 E-3
25000.	378.	399.	0.1135	3.511 E-3
30000.	458.	448.	0.1226	3.423 E-3
35000.	538.	493	0.1303	3.354 E-3
40000.	618.	536.	0.1383	3.299 E-3
45000.	697.	576.	0.1452	3.253 E-3
50000.	776.	614.	0.1516	3.215 E-3

RESULTS

It is not practical to list results of all of the treatments done in the Morrow using the recommended procedures. However, the following three treatments are included as examples of successful stimulation of the Morrow.

Well A

Well A was drilled to 10,324 ft and produced naturally for about 14 months. The operator set an openhole packer and tested an interval from 10,298 ft to 10,326 ft. This zone produced 40 MCFD. The well was fraced with 13,000 gal. of a fracturing fluid made with water converted to 1% hydrochloric acid and containing 15% isopropyl alcohol. The fluid was gelled with guar gum and silica flour was used as a fluid-loss agent. The well was treated down 2-3/8 in. OD tubing at 9.3 BPM at 5800 psi. A total of 8000 lb 20/40 sand and 1800 lb of 12/20 glass beads was used as proppant. After clean-up, production was tested at 1 MMCFD at 1200 psi.

Well B

Well B was perforated in interval between 11,372 ft and 11,456 ft and treated with 4000 gal. of 7-1/2% hydrochloric acid with ball sealers and nitrogen. The well did not respond as expected and was retreated with 10,000 gal. brine and 30 ball sealers for diverting. After treatment, the well tested at 100 MCFD. The operator reperforated the well with a casing gun and acidized with 2000 gal. of 7-1/2% hydrochloric acid and nitrogen. Production increased to 140 MCFD.

The operator was not satisfied with the production, so the well was fraced using 30,000 gal. of 3% hydrochloric acid containing 0.2% of the special surfactant, and gelled with 60 lb cellulose gelling agent per 1000 gal. A total of 13,000 lb of 20/40 sand and 3550 lb of 20/40 glass beads was used as the proppant. The injection rate was 5.6 BPM at 9300 psi. Nitrogen was added to the frac fluid at 650 SCF nitrogen per barrel of frac fluid. After clean-up, the well flowed 910 MCFD at 1200 psi.

Well C

Well C had eleven 0.32-in. diameter perforations in the interval between 13,074 ft and 13,285 ft. The well was treated with 2500 gal. of 7-1/2% HCl using ball sealers. Production after the acid treatment was 160 MCFD. The well was then hydraulically fractured with 25,000 gal. of 3% HCl gelled with a cellulose derivative and containing additives designed for improved clean-up. The proppant used was 13,000 lb of 20/40 sand and 4400 lb of 20/40 glass beads. Injection rate down a combination string of 2-3/8 in. and 2-7/8 in. tubing was 13.5 BPM at an average surface pressure of 9000 psi. Nitrogen was added at 300 SCF/bbl of frac fluid and 400 SCF/bbl of flush to aid clean-up. After treatment the well produced at a CAOF rate of 7.5 MMCFD.

CONCLUSIONS

The experience of several successful treatments in the Morrow has proved that the Morrow can be successfully stimulated *if* the potential gas production is present to be stimulated. Treatment design for the Morrow must be carefully undertaken, with all of the possible problems considered, for the treatment to be successful. If the treatments are properly designed and executed, the chances for a successful treatment of the Morrow are excellent.

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