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Sand Fracturing With Liquid Carbon Dioxide

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ABSTRACT

The quest for cleaner fracturing fluids has led to the development of sand fracturing using liquid carbon dioxide (CO_2) as the proppant carrier fluid. CO_2 is handled at the surface as a liquid at approximately 200 psi and -30°F. Special blending equipment has been developed to inject proppant directly into the liquid CO_2 at these surface conditions. The sand laden liquid CO_2 is then pumped by conventional equipment. At stabilized reservoir temperature and pressure, the liquid CO_2 vaporizes in a gas well or vaporizes and is partially dissolved in the reservoir oil in an oil well. The greatest potential of liquid CO_2 fracturing is the elimination of most of the formation damage normally associated with fracturing fluids and the very rapid clean up and evaluation of the well following the stimulation.

INTRODUCTION

CO_2 is a liquified gas that is readily applicable to oil field stimulation use because of its unique phase behavior (Figure 1). CO_2 can be transported as a liquid at -20° to -40°F. As these temperatures are non-cryogenic, the CO_2 can be pumped with conventional equipment and injected directly into the well as a liquid. Upon heating to reservoir equilibrium temperature and expanding to reservoir equilibrium pressure, CO_2 will vaporize to the gaseous state. The gaseous CO_2 will then flow back from the formation to the wellbore with the lower viscosity of the gas. It will not exhibit any surface tension as liquids do and will aid formation liquid production from the well by reducing the pressure gradient up the tubing.

References and illustrations at end of paper.

CO_2 is very soluble in crude oil and slightly soluble in water. CO_2 aids recovery in oil bearing formations as it is miscible with most crudes and greatly reduces oil viscosity. CO_2 dissolved in water will form weak carbonic acid which has a pH of 3. There is no indication that CO_2 or the resultant carbonic acid does any formation damage in sandstone reservoirs.

CO_2 has been used since early in the 1960's in fracture stimulation of oil and gas wells. The CO_2 was pumped with the oil or water based treating fluid in ratios sufficient to gas lift the liquid back to the surface after the treatment. Further development led to higher CO_2 ratios where the liquid CO_2 was effectively part of the fracture generating liquid (50%) with the proppant pumped in oil, water or methanol with conventional equipment. The improvements were the reduction of the liquid volume and the ample gas energy supplied to recover the liquid from the formation.

The latest development in CO_2 fracturing consists of injecting proppant directly into the liquid CO_2 and using liquid CO_2 as the sole carrier fluid. The obvious improvements are the elimination of residual liquid left in the formation and a fracturing fluid recovery mechanism that is not dependent upon reservoir pressure.

THEORY

Fracture stimulation is based on the principal of generating a crack or fracture away from the wellbore through the producing formation, then placing proppant in the fracture to act as an efficient drainage channel back to the wellbore. To get optimum stimulation ratios, the fracture should be propped efficiently, and the treating fluid must be removed and not cause extensive damage to the formation permeability on either side of the fracture. The primary damage due to fracturing is relative permeability loss due to the capillary pressure effect. Swelling and migrating clays can also cause substantial permeability damage. Relative permeability and capillary pressure damage becomes more critical in tight and low pressure formations. Capillary pressure increases as pore size decreases, and if capillary pressure is greater than reservoir pressure, permeability damage is complete.

Fracturing with liquid CO_2 allows the fracture to be generated and the proppant to be placed by the CO_2 in its liquid phase. At reservoir equilibrium conditions, the CO_2 will exist in its vapor phase and completely eliminate any relative permeability or capillary pressure damage along the fracture. Complete knowledge of pressure and temperature conditions of the CO_2 during the treatment is important in order to maintain the CO_2 in its liquid phase for more efficient fracture generation and proppant placement.

CO_2 FRACTURING BEHAVIOR

Figure 1 illustrates the temperature and pressure condition of CO_2 through a typical treatment cycle. For consistency all calculations in this report are based on:

Fracture Gradient	= .8 psi/ft
Reservoir Press. Gradient	= .45 psi/ft
Reservoir Temp. Gradient	= 70°+1.1°/100 ft

CO_2 is stored in lease tanks at 200 psi and -20°F. Pressure is then boosted to 300 psi at condition #2 to supply liquid CO_2 to the blender. CO_2 can be pumped by conventional equipment as long as it is maintained above the liquid vapor equilibrium line, in the liquid state. Chemicals are added to the CO_2 at the blender to improve viscosity and sand is then added directly to the CO_2 stream. Liquid CO_2 gellation and sand addition to liquid CO_2 is proprietary technology and will not be elaborated on here. From the blender the CO_2 goes to the triplex pumpers where it is pressurized to well head condition #3. Field measurement has indicated CO_2 will heat up by 4°F/1000 psi as it is pressured through a triplex pump. Pressuring from 300 psi to 5000 psi thus increases temperature by 4.7 x 4°F/1000 psi = 18.8°F. From surface condition #3 to perforation condition #4 the CO_2 will be heated by flowing through the warmer wellbore and pressure will either increase or decrease depending on whether friction or hydraulic pressure is greater. From the perforation condition the CO_2 enters the fracture and is heated to near reservoir temperature at the fracture tip #5.

Pressure will decrease slightly down the fracture because of friction loss. When the well is shut in after the treatment, the CO_2 will warm to reservoir equilibrium temperature and expand to reservoir equilibrium pressure #6. When the well is opened to flow, the CO_2 will expand to surface condition #7 and undergo an associated cooling due to gas expansion.

SURFACE PUMPING TEMPERATURE

Figure 2 can be used to obtain the wellhead temperature of CO_2 for fracturing at various depths. The surface temperature of the liquid CO_2 depends on the tank temperature and the final compressed pressure of the liquid CO_2. The graph was constructed assuming a tank temperature of -20°F, surface treating pressure = bottom hole fracture pressure of .80 psi/1000 ft of depth, and using the field measured temperature rise of compressed liquid CO_2 of 4°F/1000 psi. The surface temperature of liquid CO_2 from this graph can be used in calculation of bottom hole treating temperatures and subsequent tubing and casing force calculations.

BOTTOM HOLE TEMPERATURE

The CO_2 bottom hole temperature is of prime importance because the fracture must be cooled below the critical temperature of 87.8°F for the CO_2 to exist as a liquid and generate sufficient fracture width to allow proppant to be injected. The well bottom hole temperature at the end of the treatment is necessary to correctly calculate tubing and casing tensile forces from thermal contraction.

Figure 3 plots CO_2 perforation temperature after cool down and pad volume of 5 Bbl/100 ft. of depth. Bottom temperature calculation was based on Ramey using a pump rate of 20 BPM down tubing with oil in the annulus. Table #1 presents the bottom hole temperature calculated with various parameters changed.

A high pump rate is the most effective parameter in generating low bottom hole temperatures and extending the effective liquid penetration in the fracture . Fracturing down tubing rather than casing, and insulating the annulus with oil rather than water are very effective in lowering bottom hole temperature. Well depth, bottom hole static temperature and CO_2 pad volume have a lesser effect on the bottom hole treating temperature.

FLUID RHEOLOGY

Fluid rheology numbers for gelled liquid CO_2 were approximated by matching the data from the treatments performed to fracture geometry theory. Fracture leak off with CO_2 is primarily controlled by viscosity and expansion when the CO_2 exists in its liquid phase and by vaporization expansion when the CO_2 exists in its gaseous phase. Fluid expansion can not be handled by most fracture geometry simulators. The entry of a wall building coefficient of .01 ft/min$^{0.5}$ to account for the expansion leak off control mechanism, will generate fracture geometry calculations that agree reasonably with post treatment data.

Typical rheology numbers for a CO_2 liquid treatment in a 1 md formation are:

n'	= 0.80
k'	= 0.0005 lb/sec n'/ft^2
Fluid Leak Off Coefficient	= 0.0011 ft/min$^{0.5}$
Apparent Viscosity	= 10 cp
Spurt Loss	= .01 gal/ft^2
Wall Building Coefficient	= .01 ft/min$^{0.5}$

The CO_2 fracturing volume factor is shown in Figure 4. Based on the temperature and pressure gradients stated, it shows the volume expansion of CO_2 at reservoir equilibrium conditions. A lower reservoir pressure or higher reservoir temperature would yield a larger fracture volume factor and thus improve leak off characteristics. The relative volume of CO_2 at the various points in the fracturing cycle of Figure 1 is presented in Table 2.

TUBULAR STRESSES

To safely fracture a well using liquid CO_2, the thermal contraction and tensile stresses of tubing and casing must be considered. Safety factors of casing for various treating modes based on calculated bottom hole temperature and the resultant total casing stress are presented in Table 3. Tensile stress is calculated considering buoyant casing weight, thermal contraction stress and pressure related ballooning stress. When fracturing directly down the casing, J-55 is safe to burst pressure to depths of 5000 ft. N-80 casing to 8000 ft. has a tensile safety factor of 1.25 at casing burst pressure. For wells deeper than these limits, the casing safety factor can be increased by increasing the grade of casing, slacking off on hook load before setting slips, increasing the height of cement, or fracturing down tubing and insulating the annulus with water, oil or N_2.

Tubing thermal contraction must be calculated when fracturing through tubing with a packer. Tubing movement or tubing stress is greater than with conventional warm fracturing fluids. Although the movement and stress is greater, normal completion practices have allowed sufficient safety margins that all treatments to date were performed well within safety limits. These additional temperature contractions can be handled with present packer technology and completion practices when needed.

WELL FLOWBACK

The CO_2 pressure gradient for well flowback with CO_2 is shown in Figure 5. CO_2 in the vapor phase, when a well is on flowback, has a much different pressure gradient than natural gas because of the compressibility and associated density change.

The recommended flowback procedure has been to shut the well in to allow the fracture to heal and temperatures to rise to near geothermal gradient in order to vaporize all liquid CO_2. The well is then flowed back on an 8/64" choke for the first 8 hours. After 8 hours, the choke size can then be opened to larger settings as desired. The flowback of CO_2, both in rate and time, is not as critical compared to conventional treating fluids because of its essentially non damaging nature. Consideration should be given to whether reservoir fluids will be produced and a choke size used to ensure recovery of these fluids to prevent the well from loading up and killing itself. As with any treatment recovery, proppant flowback and choke wear should be monitored.

TREATMENT HISTORY

Over forty treatments have been performed by Fracmaster in the United States to date using liquid CO_2 as the sole fracturing fluid for the placement of proppant. Job sizes have varied from 12,500 to 120,000 lbs. of proppant in 23,000 to 89,000 gallons of liquid CO_2. Pump rates have varied from 8 to 40 BPM and pressures have varied from 700 psi at 2,300 ft. to 12,500 psi at 16,440 ft. Maximum proppant concentration depends on rate and depth but generally has varied from 4 lbs/gal. at 2,500 ft. to 2.5 lb/gal. at 16,440 ft. Larger treatment volumes and higher proppant concentrations, where applicable, can be easily handled by utilizing present equipment and CO_2 technology.

TREATMENT RESULTS

Of the wells fractured to date, 60% have been gas wells, 25% oil wells and 15% have been non commercial. Gas wells have averaged 3 days of flow after the treatment to clean up and be ready for testing. Oil wells have averaged 3-4 days of clean up prior to steady rates being established. Wells that were non commercial because of low gas production or high water production were conclusive 2-3 days after the treatment.

The data presented in Table 4 contains selected results representative of the range of treatments performed to date. Most treatments were designed to prop 30% to 70% of the drainage radius with an appropriate proppant type and mesh size for permeability contrast and fracture conductivity. The initial production results show that the smaller mesh proppants (30-50 and 40-60) can be used in the low permeability reservoirs to provide adequate fracture conductivity.

Reported initial production indicates that the CO_2 treatments have produced results that are estimated to be at least equal to what conventional treatments would produce. The average productivity increase is estimated to be 1.5 times greater than offset well data. The wells that were non commercial had production increase rates 2-3 times greater after the treatment but were economically non-commercial. Production tests and results will continue to be monitored and evaluated.

CONCLUSION

Sand fracturing using only liquid CO_2 as the carrier fluid is an economical and viable method of stimulation that offers the following improvements:

1. Creation of a propped fracture without producing any related permeability damage from fluid retention or from incompatible fluid reactions.

2. Reduction of treating fluid clean up time and associated clean up costs. Swabbing of treating fluid is completely eliminated.

3. Water or oil production is immediately visible and positively identifiable as reservoir fluid.

4. Exploration wells can be confidently fractured with CO_2 when the nature of the reservoir is unknown. There is no damage or fluid compatability problem with either gas or oil production. Initial oil production will actually be accelerated from the viscosity reduction by solution of CO_2.

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TABLE 1

PERFORATION TEMPERATURE OF LIQUID CO_2 AFTER PAD VOLUME

CO_2 Surface Temperature = -4°F

BHST °F	Depth (ft)	Insulation Fluid	Rate BPM	Pad Volume (Bbl)	Treatment Mode	Perforation Temperature °F
175	8000	N_2	20	400	Tubing	5.15
175	8000	Oil	20	400	Tubing	27.35
200	8000	Oil	20	400	Tubing	30.92
175	10000	Oil	20	400	Tubing	34.05
175	8000	Water	20	400	Tubing	43.02
175	8000	Oil	10	400	Tubing	48.98
175	8000	Oil	20	200	Tubing	53.38
175	8000	-	20	400	Casing	58.99

TABLE 2

CO_2 RELATIVE VOLUME THROUGH TREATMENT CYCLE AT 6000 ft.

Condition	Temp. (°F)	Pressure (psi)	Density (lb/gal)	Relative Volume
Wellhead	0	5000	9.58	1.00
Perforations	20	5000	9.16	1.05
Frac Tip	125	4250	7.16	1.34
Reservoir Equilibrium	135	3000	5.66	1.67
Flowback (bottom)	130	2500	4.58	2.09
Flowback (surface)	70	10	1.17	8.21

TABLE 3

CASING TENSILE SAFETY FACTORS DURING LIQUID CO_2 TREATMENT
Casing Size = 5.5 in., Pump Rate = 20 BPM

Perf Depth(ft)	Cement Top(ft)	Treatment Mode (insul)	Casing Wt(lb/ft)	Casing Grade	Csg Surf Press(psi)	Perf Temp(°F)	Casing Tensile Safety Factor
5000	3000	C	14.0	J-55	3500	-1.08	1.40
5000	5000	C	14.0	J-55	3500	-1.08	1.29
5000	5000	C	17.0	J-55	3500	-1.08	1.37
5000	5000	C	17.0	J-55	5000	-1.08	1.26
5000	3000	C	17.0	N-80	5000	-1.08	1.99
7000	5000	C	14.0	J-55	3500	.66	1.15
7000	3500	C	14.0	J-55	3500	.66	1.20
7000	5000	C	14.0	N-80	4500	.66	1.57
10000	8000	C	14.0	N-80	5000	3.60	1.24
10000	8000	T (water)	14.0	J-55	3000	2.25	1.07
10000	8000	T (oil)	14.0	J-55	3000	.20	1.22
12000	10000	T (water)	17.0	N-80	3000	4.20	1.43
12000	10000	T (oil)	17.0	N-80	3000	1.61	1.63
12000	10000	T (oil)	17.0	N-80	1500	1.61	1.75
15000	13000	T (water)	26.0	P-110	3000	8.60	1.68
15000	13000	T (oil)	26.0	P-110	3000	5.04	1.93
20000	17000	T (water)	26.0	P-110	3000	15.42	1.34
20000	17000	T (oil)	26.0	P-110	3000	9.97	1.51

* Treatment Mode: T = Tubing, C = Casing, Insul = Annular Insulating Fluid

TABLE 4

SELECTED RESULTS

Formation	Depth (ft)	Proppant Placed	Proppant Size	Production Before	Production After
Pictured Cliffs	2310	58000 lbs.	30/50	50 Mcf/D @ 10 psi	900 Mcf/D @ 450 psi
Booch	2708	21500 lbs.	20/40	217 Mcf/D @ 10 psi	872 Mcf/D @ 600 psi
Codell	7314	75000 lbs.	20/40	TSTM*	100 Mcf/D @ 300 psi w/30 BOPD
Cleveland	7804	75000 lbs.	40/60	TSTM*	400 Mcf/D + 30 BOPD
Red Fork	13366	68000 lbs.	40/60	500 Mcf/D @ 10 psi	12 MMcf/D @ 1800 psi

* TSTM: Less than 5 Mcf/D

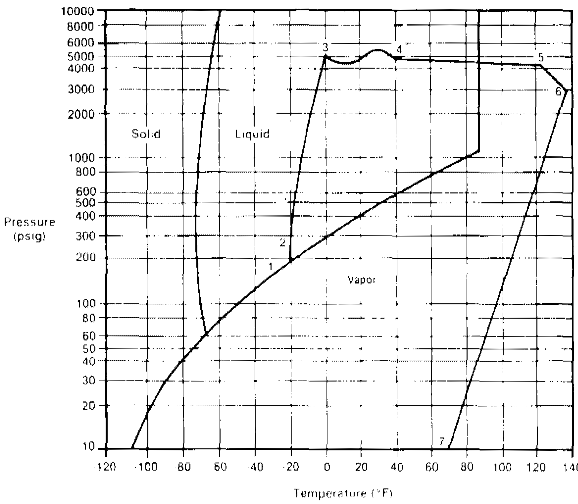


FIGURE 1
PRESSURE — TEMPERATURE OF CO_2 THRU FRAC CYCLE

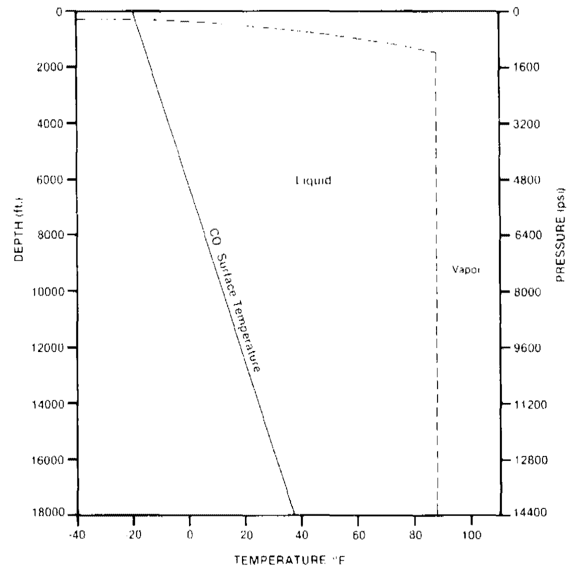


FIGURE 2
Surface Liquid CO_2 Fracturing Temperature
Assuming Surface Treating
Pressure = .8 psi/ft = Bottom Hole Treating Pressure

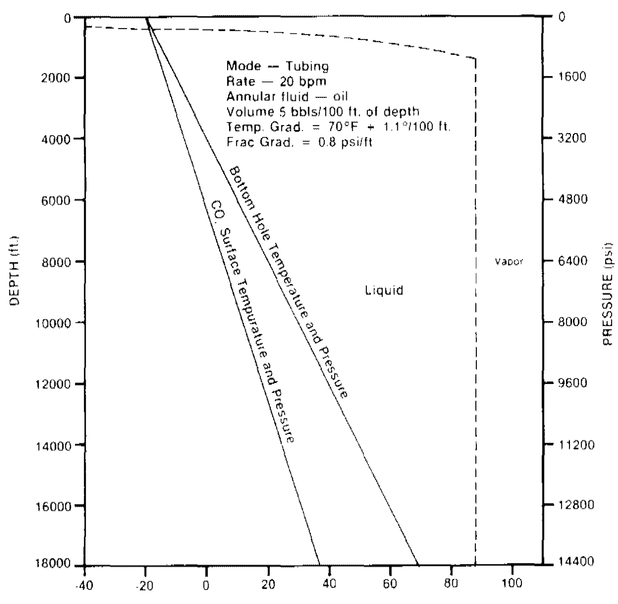
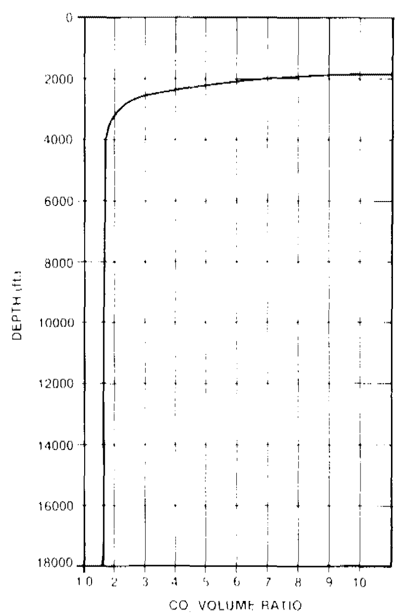


FIGURE 3
LIQUID CO_2 BOTTOM HOLE FRACTURING TEMPERATURE



BBLS at Res. Equil/BBL pumped

FIGURE 4
CO_2 — FRACTURING VOLUME FACTOR

GRADIENT GRAPH
100% CO_2

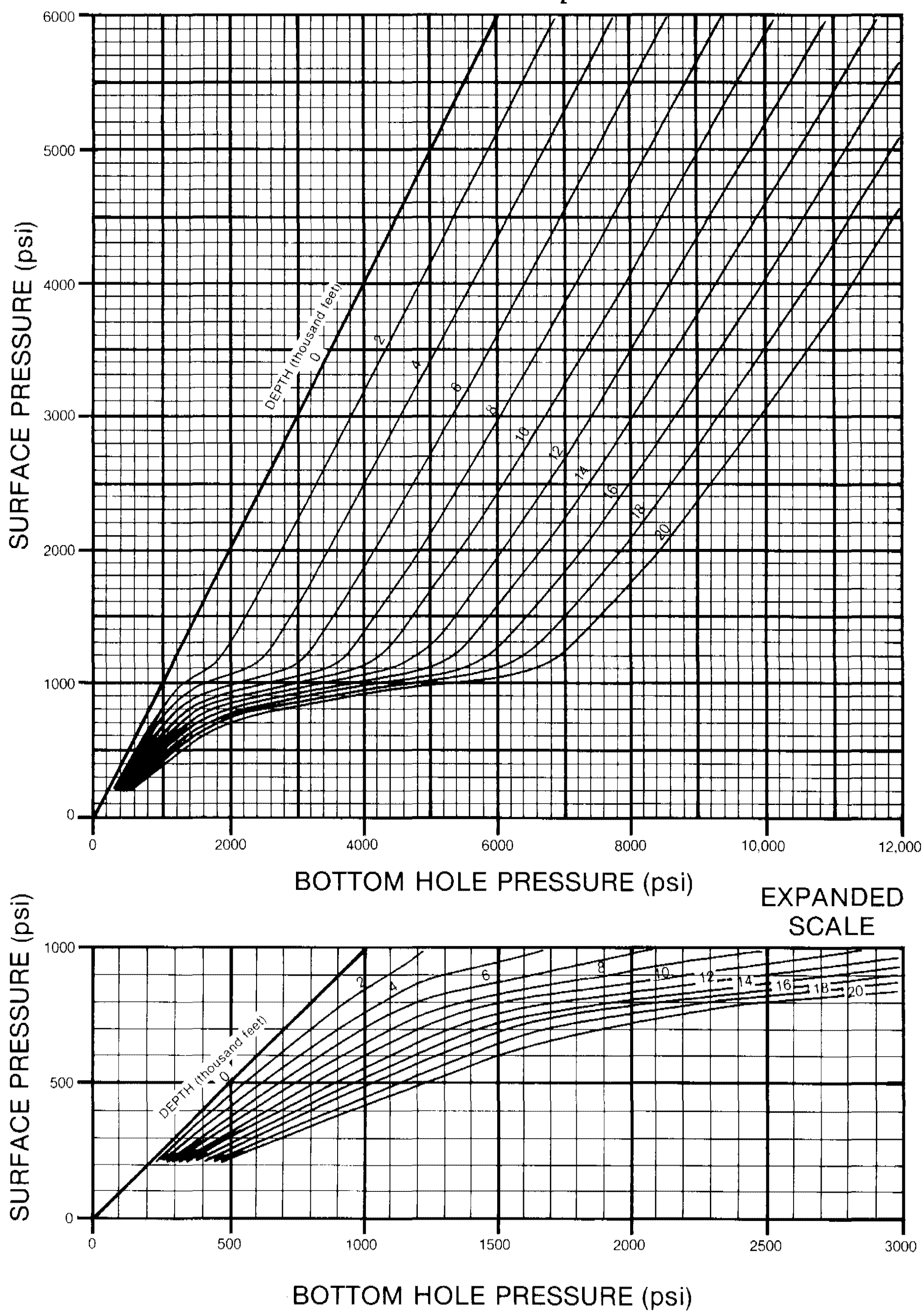


Fig. 5—Gradient graph 100% CO_2.