ANOTHER LOOK AT GAS ANCHORS

Joe Dunn Clegg
Shell Western E&P Inc.

INTRODUCTION

A review of the many types of gas anchors and their principles should be of interest to those who are concerned with pumping oil wells. The fact that free gas reduces pumping efficiency was discovered early on. An obviously better way to produce most such wells was to flow the gas up the casing annulus and pump only the liquids (oil and water). Some down-hole equipment arrangements were found to be better than others. As a result, many operators began investigating ways to improve pumping. A U.S. patent for a gas anchor was issued in 1881 to Crowley. Many more patents on gas anchors have since been issued; however, not all of them necessarily increase pumping efficiencies. The name "gas anchor" is a misnomer -- it is actually a down-hole gas and liquid separator. There are many types and their use is often misunderstood.

All the gas anchors discussed herein are for reciprocating pumps and use the principle that gas is lighter than oil or water, so that the gas bubbles will slip upward (relative to the water and oil) due to gravity. By ensuring that the oil flows downward before entering the pump, the gas bubbles will separate from the oil and water if the gas slip-velocity is not exceeded. By trial and error, the Natural Gas Anchor proved the most effective.

In West Texas in the 50's and early 60's, numerous pumping wells had serious gas interference problems. A typical well (produced significantly below the bubble point in a depletion type reservoir) had gas rates that often bumped or exceeded the 2000 GOR limit imposed by the Texas Railroad Commission. The reservoir static pressure had declined, gas caps formed or expanded, and production in pumping wells was stifled. Thus, production was lost or deferred, more energy had to be used, and wear and tear on equipment was increased -- all because of serious gas interference in the down-hole pumps.

Many operators in West Texas believed that pumping from below the pay zone caused serious problems. It was thought that extensive pump repair problems would be encountered, probably based on Gulf Coast experience in pumping unconsolidated sand formations. The idea was also held that pumping from bottom would create formation damage -- (a fear of the unknown which proved to be a myth). Thus, during this time period, some 30 years ago, most wells were pumped from above the producing formation.

There was much interest in operations of gas anchors but there were few reported controlled tests and little research on this subject -- only tests to see if oil production could be increased. Theories on why gas anchors worked (or did not work) were wide-spread. Due to the large number of variables and the lack of control of well conditions during field tests, good evaluations of gas anchors were difficult to obtain (if not impossible) in typical operations. A discussion of several of the many types of gas anchors and their performance follows.

POOR-BOY: Standard Stinger/Over-Sized/Marsh/Carlson/Immersion

The most popular gas anchor in West Texas in the 50's and early 60's (possibly even today in the industry) was the Standard Stinger poor-boy. (See Figure 1.) A better name would be "poor" gas anchor due to its inefficient operation. However, the design is cheap and causes few operating problems.

Many types of poor-boy anchors are used. (See Figure 2 through 5.) As pointed out by several authors and inventors, the key to improving gas anchor efficiency is to reduce the downward velocity of the produced mixture inside the gas anchor to below the rising (slip) velocity of gas; about .5 feet per second in a low viscosity fluid. Such a design as the Oversized (Figure 2) is an improvement on the Standard Stinger poor-boy. The Oversized has a much lower downward velocity. The original Marsh gas anchor was essentially a tandem poor-boy and cut the downward flow velocity in half. Marsh may have been the first inventor to report that the downward velocity should not exceed .5 feet per second. The Marsh gas anchor had, in a later modification, an improved hydraulic radius fluid conduit. (Figure 3)

The Carlson (Figure 4) and Immersion (Figure 5) types have high downward velocities of the liquid inside the gas anchor and provided little improvement over the Standard Stinger poor-boy. Neither the Carlson or Immersion type poor-boy gas anchors is recommended.

Most poor-boy gas anchor designs are normally hampered by the small size of the casing and the need for ample clearances. The dip (suction) tube used with such gas anchors has a restricted ID (internal diameter) that often causes excessive pressure drop. The friction loss pressure drop in the dip tube should be designed to be less than 2 psi.

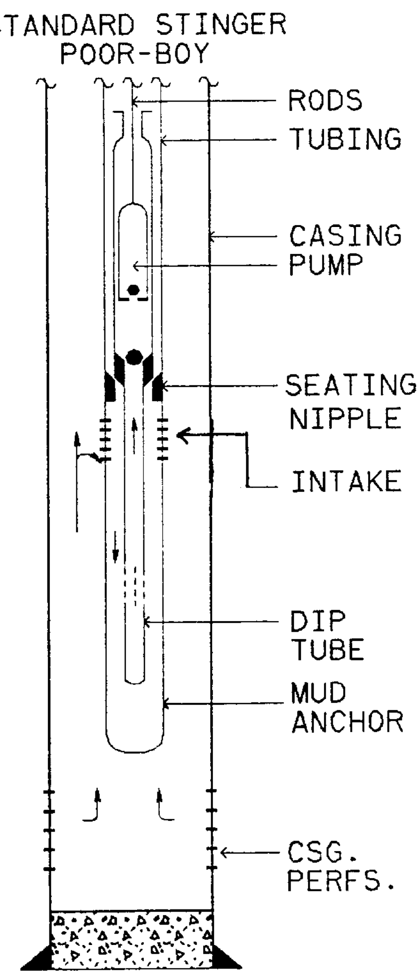

FIGURE 1

The poor-boy type gas anchors have been "successfully" used in relatively low rate wells (less than 100 BPD) with low fluid viscosity (less than 10 cp). Higher rates overload these gas anchors, resulting in little gas separation. Nevertheless, low volume wells that require higher pump settings (above the producing zone) due to sand, small liners, or junk in the hole may find the poor-boy gas anchor worth using to improve pump efficiency.

POOR-BOY TYPE GAS ANCHORS

OVERSIZED

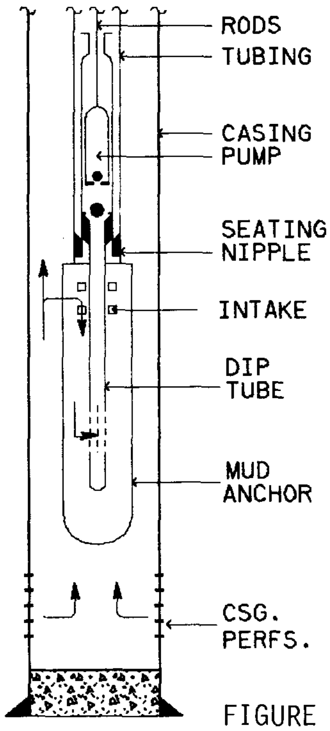

FIGURE 2

MARSH

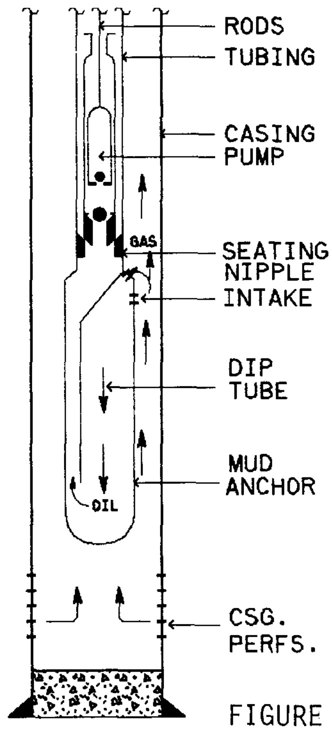

FIGURE 3

CARLSON

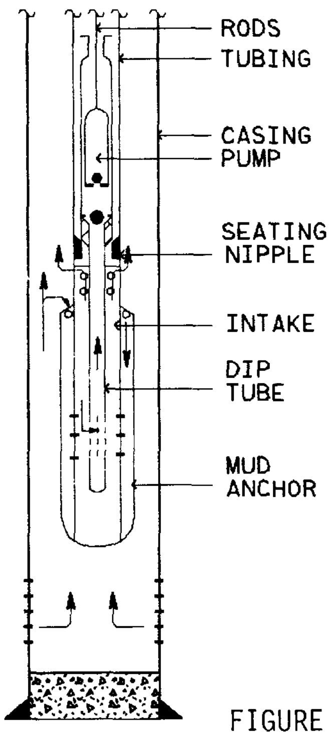

FIGURE 4

IMMERSION

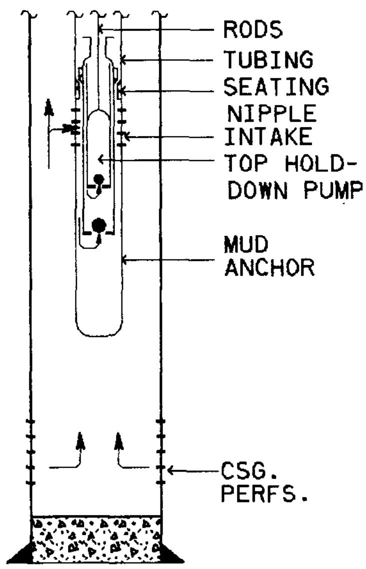

FIGURE 5

GILBERT-CUP

In the late 1950's, Wally Gilbert and Tom Nind of Shell advocated the cup gas anchor, which was commonly referred to as the Gilbert-cup. (See Figure 6.) It is simply an improvement in the poor-boy design when used correctly. Its design was based on observations and model studies in the laboratory. Flow of gas, oil, and water up the annulus of most wells is swirling, churning, and tumbling with liquid fall-back. The gas tends to flow up the high side of the well (most wells are not truly vertical) and in the unrestricted openings (not against the casing or tubing walls). As observed in model studies, a substantial amount of liquid runs down the walls mostly on the low side of the casing before being directed upward again by the gaseous fluid mixture flow.

The cups on the anchor are used to divert the gas flow away from and direct the liquids into the anchor. Model studies showed that most gas separation occurred before the fluids entered the anchor. The cups were relatively small in size with the outside diameter being the same as the upset coupling OD (outside diameter). To take advantage of the design, the Gilbert-cup should be placed above the producing formation and on the low side of the well. If the gas anchor is not centralized, gravity will normally cause the Gilbert-cup gas anchor to lie on the low side of the hole. Any tubing anchor should be placed several joints up the hole to avoid centralization of the Gilbert-cup gas anchor.

Most designs used only three to seven small cups. Use of numerous cups were attempted to improve separation efficiency, but they proved unneeded and even caused a reduction of efficiency due to anchor circulation. Model studies showed fluid entrance into the top cups and then circulation down and out the lower cups. Also, long suction or dip tubes were not found beneficial. Typically, 1" nominal dip tubes were used in 2" nominal tubing and 1¼" nominal dip tubes in 2½" nominal tubing extending 3' to 10' in length below the bottom cup, depending on the pump size and stroke.

Numerous Gilbert-cup anchors were run in West Texas in the early 1960's with good success. They were used in lieu of the poor-boy types. The Gilbert-cup cost was relatively low when bid in large quantities -- only slightly more expensive than the Standard Stinger poor-boy.

ROSWELL-CUP/MULTI-CUP

The Gilbert-cup gas anchor evolved the Roswell-cup. It was developed in West Texas by Randy Elkins and Roy Strom of Shell Oil Company. The Roswell-cup used the principle of numerous large cups in parallel -- each feeding gas-free liquids into the pump suction. (See Figure 7.) In theory, each cup is full of fluid which flows slowly downward to the bottom of the cup and then through a small, carefully sized single hole into the anchor. By using a large number of cups, the downward velocity could be sized to give a low downward flow rate with excellent gas separation. In principle, the Roswell-cup was similar to the tandem Marsh gas anchor.

SPECIALTY
GAS ANCHORS

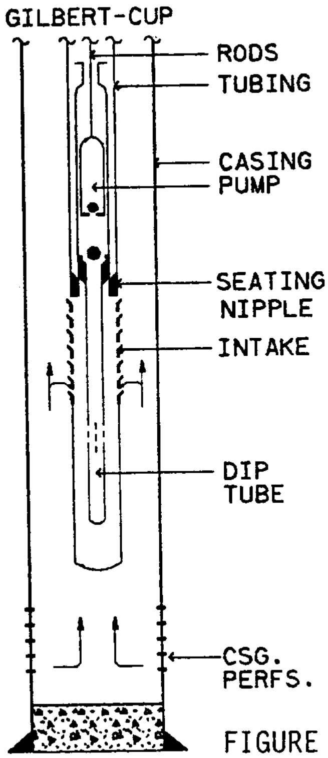

FIGURE 6

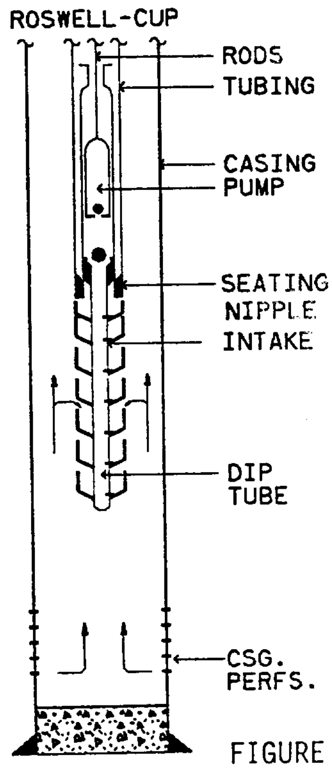

FIGURE 7

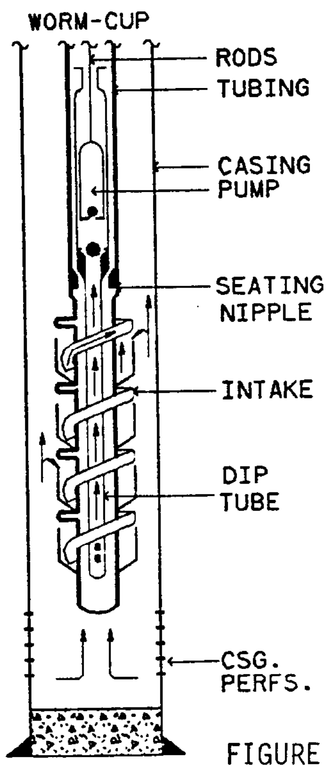

FIGURE 8

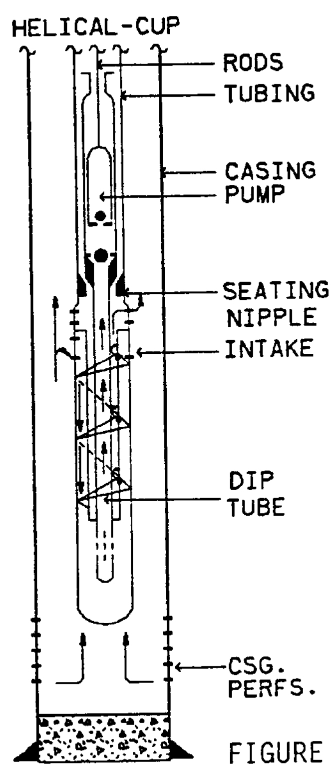

FIGURE 9

Several of the Roswell-cup gas anchors were successfully tested in the Denton, Saunders, and Townsend fields in New Mexico in 1960. Rubber cups were tried and small (1/16" and 1/8") holes were used. These anchors were relatively expensive to build but resulted in "very good performance". Because they did not appear particularly strong structurally and might have been difficult to fish, operating personnel were somewhat reluctant to run them. In addition, the holes tended to plug with rubber and scale. Sizing the holes correctly in the bottom of the cups was difficult. Laboratory studies subsequently showed that anchor circulation of fluid into the anchor at the top cups and out the bottom cups was indeed a problem.

WORM-CUP

N. C. J. Ros and others worked on improving the Roswell-cup and developed the Worm-cup gas anchor. (See Figure 8.) In the Roswell-cup, the holes in the bottom of each cup had to be big enough not to plug but had to be small enough to prevent a quick emptying of the cup and to allow liquid flow out of the anchor -- presenting a difficult design problem. This problem was at least partially solved by using a small (0.4") diameter and short (8.0") length piece of conduit (worm) as the rate control device. Each cup had a "worm" that was attached to a drill hole in the anchor body and wound around the body and tucked into the bottom of the cup. Numerous cups were used to reduce the flow rate through each cup to a small down-flow velocity.

The Worm-cup was tested in the laboratory and was successfully used in South America. This anchor may prove worthwhile in high-rate wells with large casing. It also appears to improve gas separation in high viscosity fluid wells.

MULTI-CHAMBER

Using the same basic principle as the Roswell-cup and the Worm-cup, the Multi-chamber gas anchor was developed. (See Figure 10.) The design should reduce the problem of anchor circulation. Each chamber is similar to the poor-boy; however there are several large chambers in parallel. Thus, the anchor theoretically should not be easily overloaded and should provide better gas separation. Downward flow velocity in each chamber is low and the large internal volumes of each section (greater than the pump suction volume) deters internal flow problems. A dip tube is considered optional. This anchor is less expensive to manufacture than the Roswell-cup, Worm-cup, and Helical-cup, and less likely to cause operational problems. No field tests of this anchor have been made, due primarily to the good success of the Packer and Natural gas anchor.

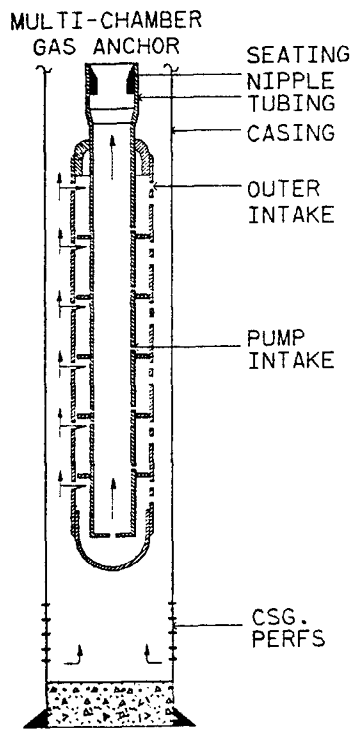

FIGURE 10

HELICAL-CUP

Another anchor that was developed in the laboratory was the Helical-cup gas anchor. (See Figure 9.) This anchor was successfully tested in West Texas in the early 1960's in a few wells. It used a Gilbert-cup for entrance, but required the downward flow to be swirled by a helical baffle -- trying to use centrifugal force to aid in gas separation. The liquids were directed outward and downward whereas the gas collected on the upside of the helix and could flow back to the annulus through a separate conduit. A rather complex anchor to build and even more difficult to explain. It worked -- but not much better than other, simpler gas anchors.

PACKER

Packer type gas anchors have been around for a long time and are one of the better ways to separate gas and liquids downhole. Like the Natural gas anchor (not yet discussed), they incorporate the casing as the down passage. (See Figure 11.) The design results in a relatively low downward velocity and permits gas to separate, resulting in an efficient gas anchor.

The Packer gas anchor can utilize various type packers and is normally set a short distance above the perforations or open hole. In some cases it may be set slightly below the operating fluid level. Flow is directed through the packer and then out into the tubing-casing annulus. There are a variety of ways to construct Packer gas anchors. (See Figures 11 through 16.) When the produced fluid spills into the annulus, the gas can easily flow up the annulus, while the produced liquids flow down into the pump suction.

The Parallel Packer gas anchor is still commonly used. It uses a special crossover that directs the produced fluid up a small string of tubing strapped to the larger production tubing. (See Figure 13.) Typically only one or two joints of 3/4" or 1" nominal tubing are strapped to 2" or 2½" nominal tubing.

In the early 60's, various modifications to the Packer gas anchor were tried. Gas separation is theoretically better at lower pressures. Much work was done on determining the optimum setting depths in wells that could not be pumped off due in part to the poor gas separation. Various lengths of small tubing were used to carry the produced fluid uphole to where pressures were lower. Care had to be taken to <u>not</u> place the gas anchor above the producing fluid level. Unfortunately, changing producing well conditions required frequent alterations.

Another approach to reduce pressure for better gas separation was the use of a downhole back pressure regulator -- tried by both B. C. Carlson and W. R. Greene. (See Figure 14.) The Regulator Packer gas anchor was run in conjunction with one joint of 1" tubing. The regulator was set to reduce pump intake pressures to about 100 psig. The idea was that this type anchor could be used in any well without knowing its productive capacity and, therefore, its producing fluid level. The Regulator Packer gas anchor seemed to improve production for a short time period. However, due to the increased complexity, this scheme was discontinued. Furthermore, most of the wells were already pumped to a relatively low pressure, thus, a back pressure regulator provided a <u>marginal</u> improvement in pumping efficiencies.

PACKER GAS ANCHORS

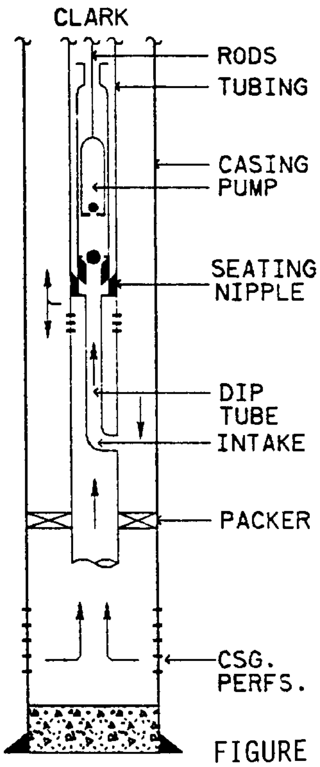

FIGURE 11

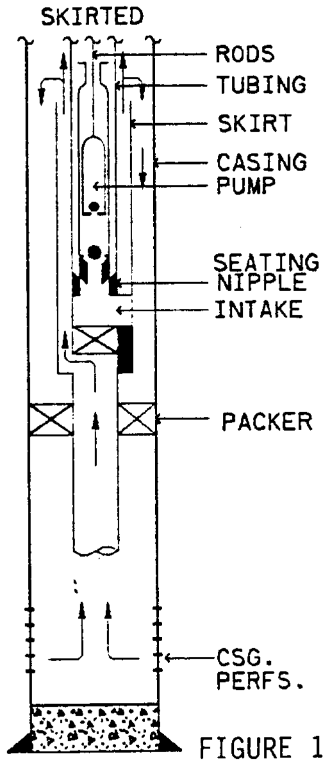

FIGURE 12

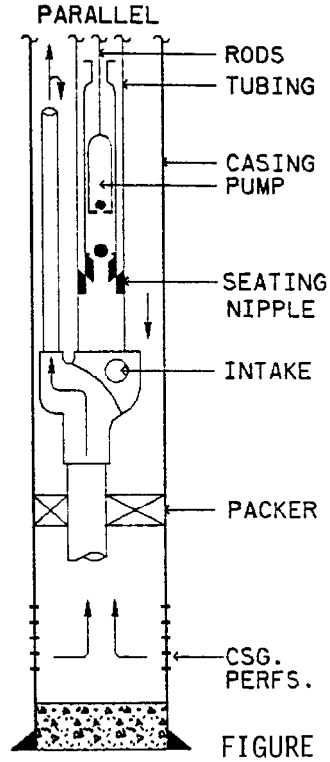

FIGURE 13

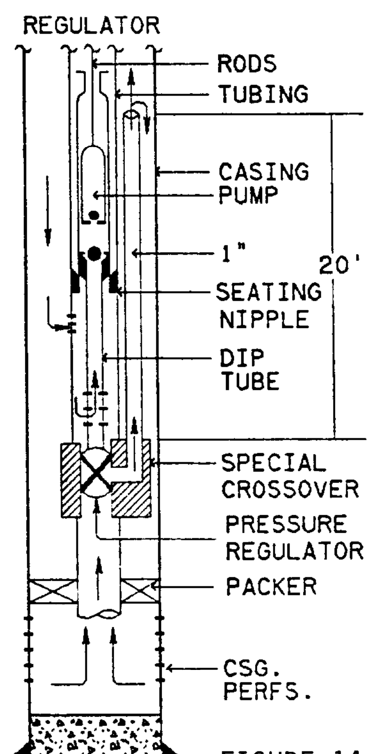

FIGURE 14

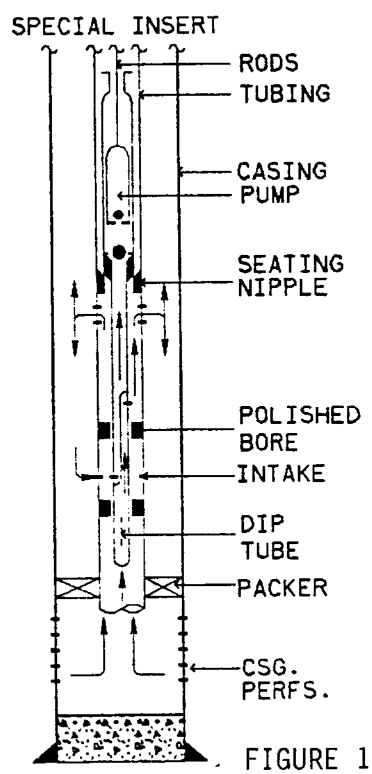

FIGURE 15

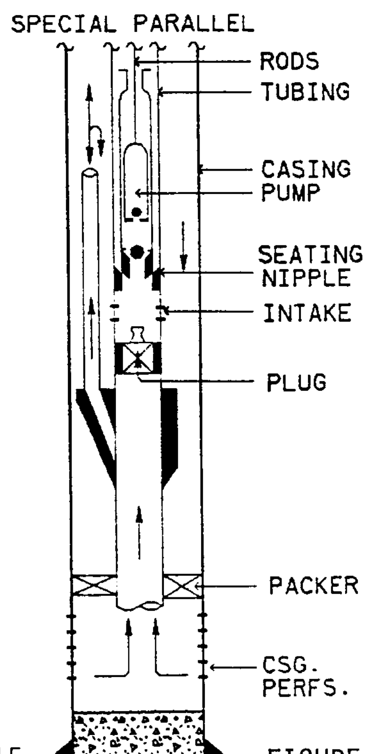

FIGURE 16

The Packer gas anchor has been used successfully where gas interference is a problem and where pumping from below the perforations is not feasible. The simple arrangements are preferred. There are a number of modifications of the packer anchor to meet local conditions. (See Figure 15 and 16.) Normally a 10' sub or one joint of tubing should be installed between the gas anchor and the packer to aid in pulling stuck packers. The length should seldom be greater than one 30' tubing joint with the seating nipple as low as feasible.

NATURAL

The simplest and most inexpensive and effective way of handling gas is to use the Natural gas anchor. (See Figure 17.) Just run the pump seating nipple a few feet below the lowermost casing perforations with a 4' perforated sub (bull plugged or orange peeled mud anchor) below. Running to near bottom of an open hole or a perforated interval also normally results in good gas separation unless most of the gas production is from the very bottom of the hole.

The key to using an effective Natural gas anchor is to drill the wells deep enough to provide a sump and to use relatively large casing (i.e., 7" OD). Low volume wells with low GLR's can tolerate small casing (i.e., 4.5" OD) but at a reduction in pump efficiency. If the downward velocity exceeds the rising velocity of gas, poor gas separation and poor pump efficiencies result.

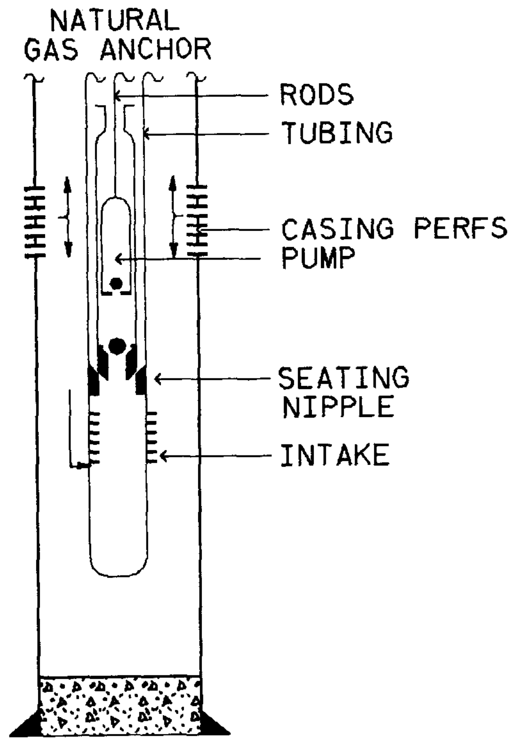

FIGURE 17

The use of the natural gas anchor in typical West Texas wells has been so successful that other type gas anchors should not be seriously considered. Only where pumping up the hole is necessary for some reason such as sand, junk, or a small liner, should some other type of gas anchor be used in similar type wells.

PRACTICES

There are a number of practices used in the design and installation of gas anchors -- some good and some bad. Some of the most common practices are discussed below.

Use of small casing significantly increases the gas separation problem. Pumping a high GLR well inside 2-7/8" casing/tubing will limit the size and design of all gas anchors and will normally result in low pump efficiencies. Both 4½" and 5½" casing cause pumping problems in high-rate (i.e., greater than 600 BPD) and high-GLR (i.e., greater than 500 GLR) wells due to the high downward fluid velocities that result. The use of 7" casing gives much more flexibility and permits higher rates in producing such wells.

Dual pumping wells are a real problem. Most such wells require a packer to isolate the two zones. Small vent strings are often used for the lower zone gas production. Such vent strings usually are inefficient due to fluid slugs in the small strings that increase the back-pressure significantly. Thus, most of the free gas goes through the pump.

In theory, for wells that cannot be pumped off/down, pumping up-the-hole will reduce loads and power requirements and may increase production due to improved gas anchor performance at lower pressures. In practice, however, this may be difficult to accomplish. Most wells have changing inflow conditions such as decreasing BHP's, increasing water cuts, changing GLR's, and changes in productivity index. Thus, to pump near the working fluid level requires frequent pump setting depth changes -- you must normally chase the working fluid level depth downward.

The calculation of the optimum setting depth is usually not precise and the process is often a trial and error approach, which is expensive. A few fields have conditions which are relatively stable and permit pumping near the working fluid level. The East Texas field is one of these. However, in this field with typical high water cuts, gas interference is not normally a serious problem. Nevertheless, loads and power should be reduced by pumping uphole.

The tubing perforations should be placed within one joint of the seating nipple and preferably immediately below it. The practice of setting the pump high with a long section of tubing below -- having the tubing intake near the casing perforations -- often causes serious gas interference problems. Typically, as the oil flows up the tubing, gas will come out of solution and then must go through the pump. During shut-in or down periods, all the free gas will collect under the pump and must be produced on start up.

The down hole pumps should be designed to minimize free gas interference problems. Relatively long, conventional, stationary barrel, rod insert pumps which are closely-spaced with small built-in clearances are normally adequate. Double valving may do more harm than good since additional spacing clearance results. Use of devices to ensure no gas-locking increase the pump cost and often reduces efficiency and production. Such devices should be used with care and any increase in production compared with the additional costs.

High back pressure on the casing reduces gas anchor efficiency. The annulus should allow the gas to flow freely to the surface without major restrictions and back pressures should be kept as low as feasible. Any tubing anchor used should have large by-pass areas. Avoid long small diameter flow lines. The surface separator pressure should be set at a minimum value.

TYPICAL CALCULATIONS

The Shell (Schmit Jongbloed) gas anchor formula predicts that the performance for each size and type is dependent primarily on the intake pressure at the anchor and the downward superficial velocity of the fluids in the anchor.

Gas anchor percent efficiency = $100/(1+C*Pwf^{.66} * Vsl^{.5})$

Other important variables are the viscosity, gas bubble size and dispersion, water cut and an overload rate. Unfortunately, the variables are different in most fields and the determination of accurate values of "C" (the gas anchor constant) is difficult for actual field conditions.

An examination of the formula shows that at zero pressure or zero velocity the anchor efficiency is 100%, meaning all gas is separated and goes up the annulus. At high velocities (greater than .5 ft/sec) inside the anchor the separation is poor and at high pressures (greater than 400 psig) the efficiencies are also poor. Note: Experiences indicate that the actual separation may be significantly greater than what the formula predicts.

In most pumping well cases, producing at maximum rates is desired. To help determine the pump capacity needed, a good approach is to investigate the cases for (1) venting all free gas and (2) pumping all free gas. In practice, the actual pumping conditions with most of the gas vented will fall in between these two extreme conditions. With a good gas anchor, less than 20% of the free gas should be pumped at relatively low pump intake pressures. (A typical pumping design case is shown in Attachment A.)

CONCLUSIONS

1. Gas interference is a common problem in most pumping oil wells and pump efficiencies can normally be improved by using a good gas anchor.

2. Excellent success has been achieved with the Natural gas anchor and it is recommended for most oil wells where pumping from near bottom is feasible.

3. The Standard Stinger poor-boy gas anchor is a poor (inefficient) gas anchor and should be used only in low volume oil wells.

4. When the pump must be set above the producing zone, the Packer anchor can be used in high-rate oil wells with gas interference problems.

5. For special high rate cases where the Natural or Packer anchor are not effective, the Roswell-cup, the Worm-cup, or the Multi-chamber gas anchors should be considered.

ATTACHMENT "A"

A typical case.

Design the gas anchor and the rod pump displacement for the following conditions:

Depth.	5000 ft
Static Reservoir Pressure.	2500 psia
Bubble Point	2000 psia
Reservoir Temperature.	110°F
Oil API Gravity.	33°
Water Cut.	50%
GOR.	540 SCF/BBL
Production Rate @ 1000 psia PWF.	400 BFPD
Formation.	Dolomite

Desired rate -- produce at well capacity and maintain a 100 psia pump intake pressure during waterflood operations.

Assume that Standing's PVT correlations are adequate.

Drilling plans call for using 5.5", 15.5 ppf casing to total depth. Experience in the field indicates few problems from producing from bottom (little solids in the produced fluids) and a Natural gas anchor should be suitable. The foreman requests that a check be made to determine if an Oversized poor-boy could be successfully used.

Calculations

An IPR curve for the outlined conditions was determined using the Vogel correlation. (See Table "A" and Figure 18.) At 100 psia the well has the capability of producing about 499 barrels of stock tank fluid per day (STB/D). At this pressure and temperature the reservoir volume will be slightly higher (504 RB/D) due to the amount of gas in solution in the oil.

The downhole displacement must be a minimum of 504 BP/D with perfect gas separation. Assuming a pump efficiency of 75%, a volume of 672 BP/D would be necessary. Is this a realistic design volume?

For the anticipated relatively high pumping rates, the use of 2-7/8" tubing was required. For a natural type gas anchor the OD of the down passage for fluids will be 4.95" and the ID will be 2.875". Thus, the downward velocity of the fluids was calculated to be about .37 ft/sec. This is less than the rising velocity of gas of about .5 ft/sec. This particular size Natural gas anchor should not be overloaded and will separate most of the free gas.

Assuming a gas anchor constant of .02 (based on laboratory data) for a Natural gas anchor, the predicted gas through the pump was calculated using the Schmid Jongbloed gas anchor formula. (See Table "A" and Figure 18.)

Also, the total oil plus free gas plus water volume was calculated using Standing's correlation. This rate is the maximum that must be handled by the pump if no gas is vented. Note at low pressures (less than 400 psia), these volumes are often quite high. At 400 psia the total volume of oil, gas, and water would be 1335 BPD and at 100 psia would exceed 6600 BPD -- showing the importance of venting the gas.

An examination of Figure 18 shows several important design considerations:

1. At above 700 psia the gas anchor formula predicts a rate higher than the total oil, gas, and water volume. For this well the value is incorrect. The formula is based on conditions of high free gas rates and laboratory tests showed poor separation at high pressures. Thus, all calculations above the intersection of the gas anchor rate and the total oil, gas, and water rate should be ignored.

2. Theoretically at zero pressure, the gas anchor would separate all the free gas. From experience, an operating pressure of 100 psia is a realistic lower pressure operating limit. In this case, if the pressure can be reduced to 100 psia, then the design rate based on the gas anchor formula would be about 635 BPD.

3. To reach the 100 psia operating pressure requires producing at the highest meaningful gas anchor rate. In this case a rate of 887 BPD maximum would be necessary. To be on the safe side, one should design for this maximum rate; however, experience indicates that the design should be based more on the 100 psia conditions.

Other conditions should also be considered in the design. Many wells may have declining rates or increasing water cuts. Also, the design should allow some flexibility for down time and pump wear. A 1.2 safety factor is recommended for such flexibility. A maximum rate of about 760 BPD would be recommended for this well.

An Oversized poor-boy (3.423" x 1.25") would be a poor choice for this well. The relative downward velocity in the gas anchor would be about .55 ft/sec and the gas anchor would be overloaded. Gas separation would be poor with any poor-boy type gas anchor. Also, use of 4.5" casing would overload a Natural gas anchor. On the other hand, 7" casing would allow higher rates before overloading and for the above conditions would require a design rate of only 715 BPD when using a Natural gas anchor. Speciality gas anchors may provide further improvements.

TABLE "A"
Typical Pumping Case

Pump Intake Pressure (psia)	Oil & Water Rate (STB)/D	Oil & Water Rate (RB/D)	Total Oil Water & Gas Rate (B/D)	Gas Anchor Rate (B/D)	Oil & Water D. Velocity (Ft/Sec)
100	499	504	6655	635	.369
200	493	501	2712	708	.367
400	478	490	1335	808	.359
700	445	462	831	887	.339
1000	399	421	592	888	.308
2000	156	176	186	377	.129
2500	0	0	0	0	0

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ACKNOWLEDGEMENT

I am grateful to Shell Western E&P Inc. for permitting publication of this paper, and to all the Shell engineers who have worked on the gas interference problem.

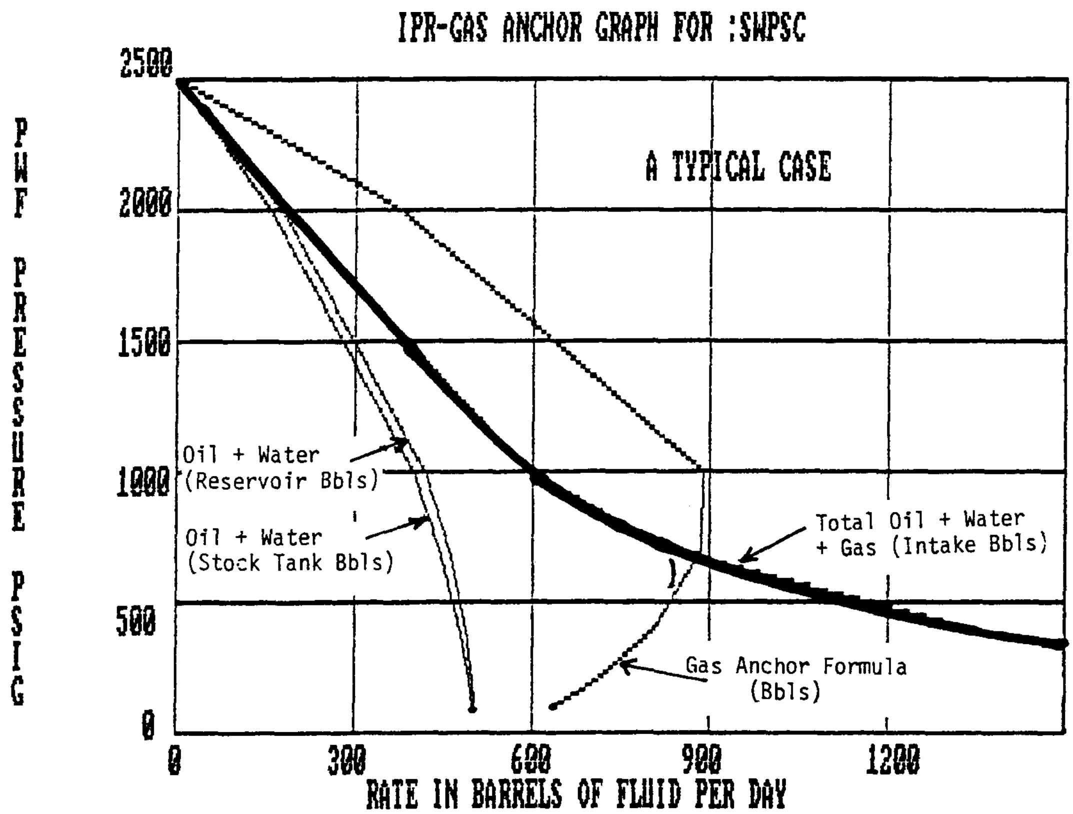

Figure 18