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GAS EVOLUTION FROM GEOPRESSURED BRINES

By
Charles S. Matthews

June 1980

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U. S. DEPARTMENT OF ENERGY
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ABSTRACT

This paper examines the process of gas evolution from geopressured brine using as a basis the many past studies of gas evolution from liquids in porous media. A discussion of a number of speculations that have been made concerning gas evolution from geopressured brines is provided. According to one, rapid pressure reduction will cause methane gas to evolve "as when one opens a champagne bottle." It has been further speculated that evolved methane gas would migrate up to form an easily producible cap. As a result of detailed analyses, it can be concluded that methane gas evolution from geopressured brines is far too small to ever form a connected gas saturation except very near to the producing well. Thus, no significant gas cap could ever form. Because of the very low solubility of methane in brine, the process of methane gas evolution is not at all analogous to evolution of carbon dioxide from champagne.

A number of other speculations and questions on gas evolution are analyzed, and procedures for completing wells and testing geopressured brine reservoirs are discussed, with the conclusion that presently used procedures will provide adequate data to enable a good evaluation of this resource.

GAS EVOLUTION FROM GEOPRESSURED BRINES

I. INTRODUCTION

Geopressured reservoirs have been known to exist along the Gulf Coast for over 40 years. The more significant geopressured formations generally lie at depths greater than 10,000 feet and at temperatures above 225°F. At first, these formations were avoided. The sudden encounter of high pressure brine in these reservoirs while drilling often led to drilling control problems requiring immediate use of heavily weighted mud. Sometimes encountering these zones unexpectedly would lead to blowouts and loss of a well.

The industry has now learned how to predict when these high pressure zones will be encountered and how to cope with them. Approximately 10,000 wells have now been drilled into the Gulf Coast geopressured zone. A significant amount of oil production and an even more significant gas production occurs from these reservoirs. A considerable body of knowledge of these reservoirs has resulted from cores and logs from these 10,000 wells and from experience with producing oil, gas, and brine from these geopressured formations. The geopressured oil and gas accumulations are always found in conjunction with geopressured brine. As the oil and gas are produced, this brine is also commonly produced. As a consequence, the industry has considerable experience with geopressured brine production at moderate production rates. Most of the geopressured reservoirs, however, do not contain oil or gas but contain only brine. It is these reservoirs that are the object of a current evaluation by the Department of Energy. Some of the important questions concerning these reservoirs are: i) How large are they? ii) Is the brine saturated with methane? iii) Are geopressured brines a significant energy source? iv) Is it possible to produce gas from these brine-filled reservoirs without producing large volumes of water?

In this report, the process of gas evolution from these high pressure brines as the pressure is lowered in the underground porous reservoir will be examined. Some of the speculations and related questions discussed include: 1) If the pressure is reduced in a geopressured brine reservoir, will methane come out of solution as disconnected bubbles or as a continuous stream of gas? 2) Will more total gas evolve if the pressure is reduced rapidly rather than slowly? 3) Will the evolved gas migrate upward to form a gas cap? 4) In what ways is the release of pressure in the underground reservoir like the opening of a soft drink bottle, and in what ways is it unlike this? 5) Can the pressure be dropped initially very rapidly, and will that initiate and maintain preferential evolution of free gas? and, finally, 6) Would the gas initially dissolved in the brine evolve and migrate up to form a gas cap? (If this were possible, one could drill into and produce such a gas cap as a conventional "free" gas reservoir.)

The suggested production method discussed in 5) and 6) above attributed to Mr. Paul Jones appeared in the May 31, 1979, edition of The Wall Street Journal and in the July 30, 1979, edition of Barron's. The concept is appealing, especially since the process is likened to "opening a champagne bottle or a carbonated soft drink bottle."

A recent Exxon patent (U.S. Patent No. 4,149,596, April 17, 1979) proposed a different procedure for gas recovery from geopressured brines. The patent noted that at the time a geopressured well ceased to flow the gas evolved in the reservoir would be at such a low saturation that it would not flow. The patent suggested, however, that by continuing to produce the brine until a low reservoir pressure of 500-1,000 psi was reached that enough gas would evolve for gas flow to take place.

Little engineering study or analysis has been made of the above questions and suggested production methods. A recent paper by Martin,¹ "A Study of Simultaneous Production of Water and Gas From Aquifers Containing Initial Immobile Free Gas," treated the case where a free gas phase already exists. However, that theoretical study did not allow vertical movement of gas. Some aspects of flow of gas evolved from solution in geopressured brines were also analyzed in a recent report by Matthews,² "Existence and Flow Behavior of Gas at Low Saturation in Geopressured Formations." However, no overall treatment of gas evolution or of vertical gas migration from geopressured zones has been made.

To provide a scientific basis for the analysis of this report, the mechanism of gas evolution from brine in a porous medium is first discussed. Next, the conditions under which the evolved gas will migrate in a uniform porous medium are outlined. Then, the type of permeability distribution found in actual geopressured reservoirs is examined, and the effect of this on gas migration is discussed. The process of evolution of gas from brine is compared with the evolution of carbon dioxide from beverages; and, finally, the possibilities for vertical gas migration and formation of a gas cap are evaluated. In all these analyses, the geopressured brine is assumed to be saturated with methane.

II. GAS EVOLUTION FROM A LIQUID

A. SOLUBILITY OF GASES IN WATER

1. Methane in Water

Data on the solubility of methane in fresh water has been published by Culberson and McKetta.³ Results are shown in Figure 1. In the temperature range of interest, 200°F-350°F, and at a pressure of 10,000 psi, up to 50 standard cubic feet (scf) of methane can be dissolved in a barrel of fresh water. The geopressured zones along the Gulf Coast contain

brine rather than fresh water. The salinity varies; but, in depths of interest, 10,000-17,000 feet, the salinity is usually in the range of 50,000-150,000 ppm total dissolved solids. Methane is much less soluble in these brines than in pure water. The reduction in solubility may be estimated from Dodson and Standing⁴ (Figure 2).^{*} At 250°F and 150,000 ppm total dissolved solids, the solubility is reduced by about 50 percent.

2. Carbon Dioxide in Water

Some authors have likened the release of methane from geopressured brine as the pressure is dropped to the formation of bubbles in a soft drink as the top is opened. To furnish basic data for such a comparison, let us first look at the solubility of carbon dioxide in water. Figure 3 shows that at pressures less than 200 psi, carbon dioxide is almost 30 times as soluble in water as methane. One volume of water at 78°F (25°C) and atmospheric pressure will dissolve approximately 0.7 volumes of carbon dioxide measured at those same conditions.

B. COMPARISON OF GEOPRESSURED BRINES AND SOFT DRINKS

The amount of gas that could evolve from a soft drink is substantial as is known by everyone; whether this is analogous to methane release from a geopressured brine may not be so obvious. Soft drinks are normally bottled at a low temperature (about 40°F) where the solubility of carbon dioxide in water is almost twice that at 78°F. Warming up of the soft drink and then removal of the cap permits release of a volume of carbon dioxide approximately equal to 0.7 of the liquid volume. The bubbles that form when this large volume of gas is released are familiar to everyone. However, the volume of bubbles that will form in a geopressured reservoir is far less. From Figure 1, we see that at 250°F a reduction in reservoir pressure from 10,000 psi to 8,000 psi allows release of about 4 scf of methane per barrel of water (from 32 scf per barrel in solution to 28 scf per barrel). At final reservoir pressure of 8,000 psi, this 4 scf of released gas will have a volume of approximately 0.002 barrels. Thus, the ratio of volume of gas released to the brine volume from whence it came is 0.002 or 0.2 percent. This

^{*}Recently, more accurate data on the solubility of methane in solutions of sodium chloride has been presented at the Fourth Geopressured Conference in a paper by Blount, Price, Wenger, and Tarullo. The data were obtained at Idaho State University on a project sponsored by the Department of Energy. Agreement between these initial results and those estimated as above are reasonably good. Prior to Blount's work, Haas (USGS open file report) presented all data available in convenient, tabular form.

compares with the volume of carbon dioxide released from a soft drink of 0.7 or 70 percent. Thus, the gas released is partially depressuring a geopressured brine reservoir from 10,000 psi to 8,000 psi and is, comparatively, only 1/350 of that released from a soft drink at atmospheric pressure. From this, it can be concluded that the analogy between soda pop, and geopressured brine is not a good one.

The contrast can perhaps be made clearer by calculating how many bubbles 1/8 inch in radius would form a soft drink-size bottle of methane-saturated brine if the pressure is decreased from 10,000 psi to 8,000 psi. The volume of each 1/8 inch radius bubble is 0.008 cubic inches. The volume of methane released in decreasing the pressure from 10,000 psi to 8,000 psi is 0.2 percent of the liquid volume, as calculated above. Thus, the volume of methane released from a six-ounce (12 cubic inches) volume of brine is 0.002 (12) or 0.024 cubic inches. The number of bubbles of methane formed is $0.024/0.008$ or three bubbles.* In contrast, the number of bubbles formed by warming and releasing pressure on a soft drink is 350 (3) or 1050. The contrast is very great. Thus, the analogy between soda pop and geopressured brine is nonexistent.

C. MECHANISM OF GAS EVOLUTION IN A POROUS MEDIUM

1. Effect of Pressure Decline Rate

The solubility data discussed above, show how much methane can be dissolved in brine. Consider now what happens as the pressure of this brine is dropped when it is contained in a porous rock.

This type of gas evolution from a liquid contained in a porous medium is an important mechanism of oil production. For this reason, gas evolution has been studied extensively^{5,6} by means of theory, laboratory research, and field observation.

Application of the results of these studies to the geopressured brines case leads to the following conclusion.

As the geopressured reservoir is produced, the pressure declines. If the brine is initially saturated with methane, then some of the methane will evolve from solution in the

*We obtain three methane bubbles for a 2,000 psi drop in pressure. The maximum pressure drop the geopressured reservoir can sustain (i.e., to hydrostatic) is about 5,000 psi. Even for the maximum pressure drop, we would obtain only about 12 bubbles in a volume of brine equivalent to the volume of a common soft drink bottle (602).

form of disconnected tiny bubbles. Studies have shown that some degree of supersaturation is required to cause such gas evolution. If the pressure were dropped relatively rapidly, such as 100 psi per day, the degree of supersaturation would be great and the evolution of gas less than the equilibrium value. Further, at such high supersaturation, the gas would evolve as many small bubbles in the liquid.

At lower rates of pressure decline, such as 1 psi per day, studies have shown that little supersaturation occurs. Gas is evolved from solution at a rate such as to maintain an approximate equilibrium amount dissolved at the new pressure. Further, at these low rates of pressure decline, the rate of bubble formation is low. A gas bubble forms initially in only about every 20 cubic inches of reservoir bulk volume.

Proponents of vertical gas migration in geopressured brine reservoirs have suggested that very rapid drops in pressure would cause significant volumes of gas to evolve. This is not true. Such rapid drops in pressure, even if achievable, would cause a high degree of supersaturation and, thus, evolution of less gas than corresponds to the equilibrium value. Further, the gas bubbles that will form will be smaller in size, more in number, and much less likely to accumulate into a few higher saturation gas channels capable of flow.

2. Achievable Rates of Pressure Decline

It is important, for economic reasons, to achieve a high flow rate in a geopressured brine well. What flow rates are achievable with safety? For an 11,000-foot well, for example, a rate of 70,000 barrels per day would produce a pressure drop of over 2,500 psi in vertical flow to the surface even in large 5 1/2-inch production tubing. This pressure drop is about half the total available. As the pressure drop in the formation would also be large at this rate of flow, the flowing life of well at this rate would be short in known geopressured reservoirs. Of more serious consequence is the fact that at this high flow rate, small solid particles (rust, scale, etc.) in the flow stream would quickly erode a hole in the tubing causing a serious problem of safety. A range of 30,000-50,000 barrels per day is about the highest achievable with safety even with large 5 1/2-inch tubing.

At this rate of production, how fast will the pressure decline in a geopressured reservoir? This, of course, depends on the size of the geopressured reservoir. A number of studies^{10,12} have shown that to be of practical interest, a geopressured brine reservoir must be capable of sustaining a rate of 30,000 barrels per day for a period of ten years

more. These same studies have shown that the expected brine recovery is the order of 3 percent of the brine in place. From this, we can calculate that a geopressured brine reservoir must contain at least some 3 billion barrels of water to be of interest.

What would be the rate of pressure decline in such a geopressured reservoir? A representative reservoir (see Table 2) would have its pressure reduced from about 12,000 psi to a final pressure at depletion of 8,000 psi in 10-25 years. Thus, the maximum rate of decline would be $4,000/365 (10) = 1$ psi per day. At such a rate, as discussed above, the rate of gas evolution is approximately at equilibrium. Further, the rate of bubble formation is low. No other bubble will form within a radius of a few inches around each initial bubble (20 cubic inches volume).

Some proponents of gas production from geopressured reservoirs have suggested that a geopressured brine reservoir should be opened rapidly to a high volume flow. The question immediately arises as to whether it is even possible to drop the pressure sharply in a large underground porous brine reservoir. While it is, indeed, possible to drop the pressure sharply in a champagne bottle by suddenly releasing all the gas at the top of the bottle, there is no analogous gas cap above these underground geopressured brine reservoirs. As an alternative, it has been suggested that the pressure be dropped sharply in a well drilled into the brine reservoir. As noted above, a geopressured brine reservoir of practical interest must contain about 3 billion barrels of water. Since our well can only produce 30,000-50,000 barrels per day, only 1/100,000 of this volume can be produced each day. Production of this small amount cannot possibly sharply drop the pressure in the huge brine reservoir. Again, the analogy to champagne or soft drinks is inappropriate: opening a well to production is in no way similar to releasing the gas suddenly from a bottle of champagne.

It would, indeed, be possible to drill many additional wells into the reservoir and to simultaneously open all to production. This would achieve a rapid pressure drop in the vicinity of each well. However, unlike champagne, the geopressure brine is contained in a porous rock. This porous rock dampens the rate at which a pressure disturbance can be transmitted through the reservoir. The pressure in the brine some distance away from the wellbore can only decrease as brine is removed at the well. As this occurs, the brine can flow or expand toward the well bore through the pores in the rock. The rate at which a pressure disturbance can be transmitted through a porous rock containing brine depends on the ratio of the rock permeability to its

porosity. The higher this ratio the more rapidly a pressure disturbance will transmit. For a typical 10 md, 20 percent porosity rock, a sudden pressure drop of 1,000 psi at the well would produce in one day a drop of only 20 psi at a distance of 200 feet. At 250 feet, there would be no measurable drop in pressure in one day. The porous medium acts as a damping device, preventing any sudden pressure reduction from propagating rapidly through the reservoir.

It has also been suggested that releasing the pressure sharply in a well will cause evolution of more gas in a reservoir than releasing the pressure gradually. References 5 and 6 discussed above under "Effect of Pressure Decline Rate" show that the opposite is true. These studies showed that release of pressure at a slow rate will cause more gas to form at a given pressure than will the rapid release of pressure.

3. Growth of Bubbles

Once a gas bubble forms and as pressure continues to decline, that gas bubble will grow in size by diffusion of gas through the brine. At rates of pressure decline of the order of 1 psi per day, no other gas bubble will form within about 20 cubic inches around each initial bubble. The quoted studies (References 5 and 6) have shown that diffusion of gas is fast enough in such a volume to prevent any supersaturation. Thus, initially formed bubbles tend to grow at intervals of a few inches in the porous rock. At very high rates of pressure decline, additional bubbles will continue to form. In this case, the liquid within a few cubic inches around each initial bubble will soon contain a myriad of small bubbles rather than one growing bubble. As additional bubbles form, they will become so closely spaced that diffusion of gas into them will finally cause them to grow. The difference between slow and fast pressure drop is in the number of bubbles--more bubbles form for a rapid pressure drop.

4. Formation of a Continuous Gas Phase

As the gas bubbles grow, they eventually link up throughout the pore structure of the reservoir rock. The saturation at which this occurs depends on the distribution of pores. If there is a continuous distribution of pore sizes with some well connected large pores throughout, the gas will connect at a low saturation of about 2-5 percent. This is the range we would expect for the better permeable sands in the geopressed zone. If the gas saturation builds up to a value

higher than that at which a continuous gas phase is formed, it will begin to flow. If the saturation is less, the gas will remain trapped and will not flow. Further, a higher gas saturation must be reached for the many small bubbles produced at high rates of pressure decline to link up and form a continuous gas path through the pore than for the large bubbles produced at a low rate.

III. GAS MOVEMENT IN POROUS MEDIA

A. CRITICAL GAS SATURATION

In the previous qualitative discussion of how a connected or "critical" gas saturation develops, it was noted that the saturation value at which connection develops depends on the type of porous medium. The quantitative relationship between the ability of gas to flow, and the gas saturation must be measured experimentally in the laboratory for each porous rock of interest. A typical curve of relative permeability of a rock to gas and water is shown in Figure 4 (from Reference 7). For this case, the gas saturation at which gas begins to flow is about 5 percent as shown at point b.

B. RELATIVE PERMEABILITY

Relative permeability is defined as the permeability to a flowing phase (gas or water in this case) divided by the absolute permeability. As may be seen, the presence of a small gas saturation of 5 percent reduces the relative permeability to water from 100 percent to about 70 percent. This large reduction is caused by the fact that, in general, reservoir rocks are strongly "water wet".* Because of the attraction between the rock and the polar water molecules, the finer pores and crevices of the porous rock will be filled with water while the larger pores will contain the gas evolved from solution. The presence of bubbles of gas in the larger pores greatly decreases the ability of these pores to transmit water. Thus, as shown on Figure 4, the presence of a 5 percent saturation of gas decreases the relative permeability to water by 30 percent. As the gas saturation increases, the permeability of the rock to water decreases, finally reaching zero at about a 30-percent water saturation. At this point, the water is continued in fine pores and crevices and is no longer effectively connected.

*In nearly all underground porous rocks, there is a strong attractive force between the rock surface and water. This attraction is particularly strong between sandstones, which are composed mainly of silica, and water, which is polar. Evidence of this attractive force is given by the rise of water in a glass (silica) capillary. The inability to drain all the water from a sand pack is also evidence of this same attraction. See Reference 8 for a more complete discussion.

From Figure 4, it can be seen that as the gas saturation increases the permeability to gas rises, finally reaching, effectively, 100 percent of the absolute permeability at a gas saturation of slightly greater than 80 percent (corresponding to a water saturation of slightly less than 20 percent). One point should be emphasized in ending this discussion of relative permeability:

No gas can flow in the reservoir unless the gas saturation exceeds the "critical" gas saturation. This saturation varies with the porous medium. It is in the range of 2-5 percent for porous sandstones of practical interest for high production rate geopressured wells. In geopressured brine reservoirs thus far delineated (see Table 2 for some examples), the dissolved gas saturation is about 30 scf per barrel of water. If the pressure in a typical reservoir is reduced to hydrostatic conditions, about 7 scf of gas would evolve for each barrel of water. At a pressure of 7,000 psi, this gas would have a volume of about 0.5 percent of the liquid space. This is far less than the 2-5 percent required to form a connected gas saturation. Thus, even at abandonment, the gas saturation would not connect and could not flow in the bulk of the reservoir. Later discussion will indicate that evolved gas can flow very near the production well.

Throughout this report, it has been assumed that the useful life of a geopressured well ends when it ceases to flow. A recent Exxon patent (U.S. Patent No. 4,149,596, April 17, 1979) proposes that at the end of the flowing life of the well, methods of artificial lift be used to continue brine production. By continuing production, the reservoir pressure would be reduced to 500-1,000 psi. At these pressures, sufficient gas would evolve from brine in the reservoir to form a connected gas saturation. This gas would flow to the well bore as long as liquid continued to be pumped.

This is an interesting idea, and, in theory, is correct. Two major problems prevent the idea from being practical:

1. Energy Deficit While Pumping

The energy required to lift the brine from a deep geopressured reservoir is greater than the energy contained in the methane dissolved in the produced brine (Reference 10). Thus, until the low reservoir pressure of 1,000 psi is reached and gas begins to flow in the reservoir, there is a net loss of energy while pumping brine. To pump approximately half the total brine to be produced at an energy loss would be economically and energetically ruinous.

2. Constraints on High Rate Pumping at Depth

No practical method exists for pumping brine at high rates from a deep (15,000 foot) reservoir when the reservoir pressure is low (less than 3,500 psi). The only current system for pumping at this depth and at these low reservoir pressures would be rod pumping. The low (200 barrels per day) rate achievable from such a pumping method would give gas rates far too low to be of interest.

A complete discussion of this patent and the suggested method is given in Appendix A. That discussion confirms that the useful life of a geopressed brine reservoir is the flowing life. During the flowing life, no external energy is expended in lifting the brine to the surface.

IV. GEOPRESSURED RESERVOIR

A. NATURE OF VERTICAL PERMEABILITY DISTRIBUTION

1. Sandstone Deposition and Geopressuring

We will first consider how the Gulf Coast geopressed zone was formed. This subject was covered in the Proceedings of the First Geopressed Geothermal Energy Conference. Figures 5 and 6, from those Proceedings, show the boundary of the Eocene and Miocene sand deposits, which form the major portion of the geopressed zone. The sediments which formed this geopressed zone were primarily clay and sand; the clay is largely montmorillonite, the sand mainly quartz. These sediments were deposited by rivers along what is now known as the Texas and Louisiana Coastal Plain and adjacent Gulf Continental Shelf.

The deposition was accomplished in eight major cycles shown schematically in the profile, Figure 7, adapted from Bruce. This profile crosses the South Texas Coastal Plain near Corpus Christi. Each younger deltaic system overrides its predecessor, forming a wedge of deposits that gradually thickens gulfward.

As deposition progressed, sandy deposits overloaded under-compacted shale which then drained into adjacent sands like a filter press. This caused progressive subsidence and faulting. In the geopressed section, the resultant master faults, shown schematically on Figure 7, have been and continue to be the major avenues of water discharge from the high pressure sands, which are draining the adjacent shales. Sand beds in the down-thrown block drain adjacent clay beds and discharge water at high pressure into the planes of the master faults. The faults open and carry water off as the

pressure builds up and close and become sealing as the pressure is relieved. Drainage of water from the shales is accompanied by shale compaction, and the resultant losses in permeability in the shales gradually shuts off the flow into the sands. The water in the sands remains at high pressure (geopressure) as the fault closes and becomes sealing at a pressure somewhat below 1 psi per foot of depth.

The cause of the geopressuring along the Gulf Coast is, therefore continued deposition of sediments and the consequent formation and concurrent activation of growth faults. These faults later become impermeable boundaries sealing and maintaining the abnormal pressures of the deep lying formations. These faults severely limit the lateral dimensions and thus the size of the resource which can be exploited by an individual well of the reservoir. These faults restrict lateral flow. Restrictions on vertical flow result from the sands and clays which formed the geopressured reservoirs being deposited in cycles lying alternately one over the other. Clays or shales have very low vertical permeability and consequently restrict the vertical movement of fluids from the sandstones, as discussed below.

2. Sand Distribution

The Frio geothermal fairways determined by the University of Texas Bureau of Economic Geology, are shown in Figure 8. Figure 9 provides a typical cross section of the sand distribution in the Frio of South Texas as outlined by the University of Texas geologists. Note the general lack of sand continuity. This is typical of cross sections through the geopressured zone in Texas and Louisiana. Bebout, Agagu, and Dorfman have described the sand distribution as follows: "The Tertiary of the Gulf Coast is made up of a number of sand-shale packages that dip steeply into the Gulf of Mexico. Each of these packages also thickens considerably in the same direction, forming a wedge-shaped body. The wedges are dominantly shale with scattered, discontinuous sand bodies at the thin, landward end; thick sand with thin shales in the central portion; and thick shale with thin relatively continuous sands at the downdip portion of the wedge."

From examination of Figure 9, it can be concluded that lateral continuity of sands in the geopressured sands is generally poor over a distance of miles. Even for sands zones that are connected by stippling in Figure 9, there is considerable doubt as to whether the individual sands are laterally connected.

3. Vertical Sand and Shale Layering

Figures 10 and 11 show typical well logs in the geopressured zones. The logs have been annotated to delineate the shale and shaly intervals from the sand intervals. The self-potential (SP) curve to the left of the annotations is generally diagnostic in distinguishing sands from shales, as may be seen.

Note that even in a rather sandy interval, such as "C" in Figure 10, there are numerous shaly or otherwise "tight" streaks. These intervals would effectively block the vertical flow of gas. Any gas that evolved from solution and attempted to migrate vertically would reach a shale barrier and stop. It could then move upward only by migrating laterally updip at the underside of the shale as indicated schematically in Figure 12. If the shales are laterally discontinuous, the gas might eventually migrate to the top of a structure by a tortuous path through the shales.

Even in a highly sandy section, there are always thin layers of less permeable silt. The basic reason for this is that sediments are deposited in relatively horizontal layers. As the deltaic system which deposited the sediments moves laterally with time, the finer clay and silt sediments tend to alternate with coarser sediments in even the sandy sections. Thus, gas attempting to move vertically would encounter a series of lower permeability silt and shale streaks in series with the high permeability sand layers.

Figure 13 shows a typical core analysis from a core in the Frio geopressured zone. Note the streaks of shale in the sandy sections of the core. These layers will drastically retard the rate of vertical gas movement.

B. VERTICAL MOVEMENT OF GAS IN A RESERVOIR

1. Pressure Distribution in a Reservoir

Before gas can move in a geopressured reservoir, two things must happen: (1) gas must evolve from solution, and (2) gas must build up to a saturation above the critical gas saturation of 2-5 percent.

For gas to evolve from solution, the pressure must decrease, as will be described below.

As geopressured brine is produced from a well, the pressure distribution will be logarithmic in a radial direction as shown in Figure 14. The effect of this is to concentrate the pressure drop near the well. The following table illustrates this for single-phase, steady-state flow and a 2000 psi pressure drop between an outer radius of 5000' and the wellbore.

TABLE 1
PRESSURE DROP NEAR A WELL

<u>RADIUS</u> <u>FT.</u>	<u>VOLUME ADJACENT</u> <u>TO THE WELL</u>	<u>PRESSURE</u> <u>PSI</u>	<u>PRESSURE DECREASE FROM</u> <u>ORIGINAL PRESSURE</u> <u>PSI</u>
0.5	0.	7000	2000
10	0.0004	7650	1350
100	0.04	8150	850
1000	4.	8650	350
5000	100.	9000	0

Note that in 96 percent of the reservoir (from 1000' radius to 5000' radius) the pressure has decreased from the original value by 350 psi or less. At the well itself, the pressure has decreased by 2000 psi. Thus nearly all of the pressure decrease occurs relatively near the well. The consequence of this pressure decrease and its effect on gas evolution is discussed in the sections 3 and 4, which follow section 2 (below).

2. Geopressured Brine Prospects

The University of Texas Bureau of Economic Geology, and the Louisiana Geological Survey have conducted a multi-year study to outline the best prospects for geopressured brine production in Louisiana and Texas. The best prospects were chosen on the basis of high permeability and thickness, and expected lateral continuity. The most highly regarded areas containing these prospects are shown in Figure 15. The National Petroleum Council Committee on Unconventional Gas Sources examined these prospects and on the basis of an economic analysis selected the best of these geological and reservoir prospects in Louisiana and Texas as listed in Table 2.

TABLE 2
PROSPECT EVALUATION SUMMARY

PROSPECT NAME	AVERAGE			
	DEPTH FT.	TEMP. °F	PRESS. PSI	DISSOLVED METHANE* SCF/BBL
I. Louisiana				
Atchafalaya Bay				
East	15,200	270	12,160	29
West	13,300	240	10,640	23
Johnson's Bayou	11,400	230	9,500	20
LaFourche Crossing	15,000	270	12,900	38
Rockefeller Refuge	16,500	320	14,200	51
S.E. Pecan Island	15,565	300	13,500	35
II. Texas				
Austin Bayou	14,500	315	11,600	21
Candelaria	12,000	275	9,750	28
Clinton	11,500	275	8,250	28
Eagle Lake	12,450	315	9,335	30
Average for 10 Prospects				30

*Brine assumed to be saturated with methane with no "free gas."

3. Gas Evolution, High Permeability Case

For the 10 prospects, the average dissolved methane content (assuming the brine to be saturated) is about 30 std. cubic feet per barrel of brine. A typical solubility curve for this case is plotted in Figure 16. A typical depth for this case would be 15,000 feet. In the case where the permeability of the reservoir is extremely high so that horizontal pressure gradients in the reservoir can be neglected, the maximum drop in pressure that can occur between the 12,000 psi initial pressure and hydrostatic pressure at 15,000' (i.e., where the well flow rate falls to zero) is about $12,000 - .465 (15,000) = 5000$ psi. From Figure 16, it can be determined that a drop of 5000 psi will liberate about

7 std. cubic feet of methane per barrel of water. At final pressure of 7000 psi, this evolved gas will occupy only about 0.5 percent of the pore volume of the rock. Since this is far less than the 2-5 percent gas saturation required before it will flow, it can be concluded that very permeable geopressured reservoirs will never reach gas saturation levels (obtained via evolution from brine) at which gas flow will occur. Accordingly, no vertical gas flow will ever occur in the reservoirs.

4. Gas Evolution, Low Permeability Case

The above analysis disregards the pressure gradients in a reservoir which cause liquid to flow toward a well.

The pressure distribution in a reservoir of lower permeability is illustrated in Table 1, where a 2000 psi drawdown is required to achieve the desired brine production rate of 30,000 B/D. The wellbore pressure in this 12,000 psi reservoir cannot decrease to less than about 7000 psi, or will flow will cease. At the time the pressure at the well decreases to 7000 psi (from 12,000 psi initial pressure) the pressure at the outer radius will be 9000 psi. The pressure and the pressure decrease from original at this time are shown in Table 3.

TABLE 3
PRESSURE DECREASE NEAR A WELL

RADIUS FT.	VOLUME ADJACENT TO THE WELL %	PRESSURE PSI	PRESSURE DECREASE FROM ORIGINAL PRESSURE PSI
0.5	0	7000	5000
10	0.0004	7650	4350
100	0.04	8150	3850
1000	4	8650	3350
5000	100	9000	3000

Thus for a 5000 psi decrease from original pressure at the wellbore, the decrease from original pressure in 96 percent of the reservoir will be 3350 psi. Figure 16 shows that a 3350 psi decrease in pressure would liberate only 4 std. cubic ft. of methane per barrel of water. This would increase the gas saturation by only 0.2 percent, far less than the 2-5 percent required for flow of vertical gas movement would take place.

The gas saturation near the well differs from that some distance away. As an approximation of the near-well effects

it can be assumed that all the production from a reservoir originates outside a radius of 100' around the producing well.*

All produced liquid then suffers a pressure drop of 1150 psi in flowing from the 100' radius to the well (see Table 3). Figure 16 shows that a pressure decrease from 8150 psi to 7000 psi will release from solution about 2 SCF methane per barrel of water. Suppose that the well produces at a rate of 30,000 B/D. The pore volume in a 300' thickness of 28 percent sand to 100' radius is 470,000 bbls. At a production rate of 30,000 B/D, and a pressure drop of 1150 psi (8150-7000) inside the 100' radius, the average gas saturation will reach 2 percent after 300 days. At this point, gas can begin to flow. The volume out to 100', however, is only 0.04 percent of the reservoir volume. Accordingly, in 99.96 percent of the reservoir, no gas flow is occurring.

In the small volume near the well, gas can flow. Will it move up and segregate or will it flow into the well and be produced? To answer this question refer again to Table 3. The pressure drop between the 100' radius and the wellbore is (8150-7000) or 1150 psi. The average pressure gradient causing gas to flow toward the well is 11.5 psi/ft. The buoyant force of gravity is approximately .433 (sp. gr. water - sp. gr. gas) = $0.433 (1.08 - .20) = 0.4$ psi/ft. The pressure gradient tending to move gas toward the well (11.5 psi/ft.) is more than 25 times as great as the force of gravity tending to cause vertical flow (0.4 psi/ft). For the case considered, the total amount of gas released near the well is 30,000 B/D x 2 SCF/BBL or 60,000 SCF/day. At the most, 1/25 of this would tend to migrate vertically. Thus about 2400 SCF/day could migrate vertically. The daily gas production through the well would be 30,000 B/D x 30 SCF/BBL or 900,000 SCF/D. The ratio of vertical migration to production is 2400/900,000 or 0.3 percent. This is a maximum rate because of the previously discussed presence of silty and shaly layers which will tend to further decrease the rate of vertical segregation. More than 99.7 percent of this gas arriving near the well will be produced at the well (mostly in solution in the water) with less than 0.3 percent segregating vertically. In one year, the total amount of segregation would be about one day's total gas production. Vertical segregation is negligible.

*A 300' thick, 28 percent porosity sand would produce only 23,000 bbls (by 5 percent expansion) inside this radius. This is less than one day's production of a geopressured well of interest.

V. WELL COMPLETION

Important to the recoverability of natural gas is the method of well completion. Some proponents of geopressured geothermal energy have advocated a "barefoot" completion, alleging that this will give greater productivity and could cause earlier gas evolution. An evaluation of this proposed completion method and the reasons for using alternative completion methods is discussed in the following sections.

A. BAREFOOT COMPLETIONS

"Barefoot" completions are accomplished by not setting casing through the reservoir section. The barefoot type of completion advocated is well known and widely used in completing shallow wells in unconsolidated sands. One method of making such a completion is to cement casing at the top of the formation of interest and to then drill the well to the full depth in the producing sand, using mud to hold the wellbore open. Next, the screen*, fitted with a short extension of pipe, is washed down through any drill cuttings that may have settled in the hole. After setting the screen, the production well must be "developed" to remove drill cuttings and drilling mud and to remove the fine silt and sand around the screen to produce a coarser and more uniform sand and gravel envelope around the production well. Development is done in a variety of ways including pumping, surging, injection of compressed air, and backwashing.

The theory of the above completion method is to exclude only the coarse sands, allowing the fines to be produced initially during "development" or early cleanup. If done carefully, this procedure can product a natural sand pack of high permeability around the screen which will eventually exclude further fine sand production.

B. FEASIBILITY OF A BAREFOOT COMPELTION

A barefoot completion is not at all feasible for geopressured brine wells. The productive interval in these wells consists of thick sections of consolidated or compacted sandstone broken by shale layers, such as shown in Figures 10 and 11. None of the prospect geopressured reservoirs shown in Table 2 consist of loose unconsolidated sands. The sands are highly compacted. At very high production rates some of these formations may produce some sand particles. However, in no case would it be feasible to "wash" in a screen and "develop" the well as described above. The formation is too consolidated to ever form a stable sand pack around a screen. There is much evidence for this. Swanson¹¹ presented data on a number of cores from geopressured zones. In all cases, the sands were well consolidated. Recent cores taken in the Brazoria County geopressured well, Pleasant Bayou No. 2,

*The "screen" refers to a slotted section of pipe wrapped in a wire screen. See Figure 17.

were found to be well consolidated and to have low compressibility. The author knows of no examples of loose geopressured sands in the depth range of the prospects in Table 2.

C. FEASIBLE COMPLETION METHODS FOR GEOPRESSURED ZONES

The petroleum industry has conducted a large amount of research, development, and field testing of proper ways to complete geopressured wells. A very significant fraction of current gas production along the Gulf Coast comes from geopressured zones. Current income depends directly on production rate. It is to the industry's self-interest to obtain the best well completion possible. In some cases, gas wells are produced at velocities in the formation comparable to those planned for geopressured wells. At these high velocities, any loose sand would tend to be produced with the gas. The industry has found that, in many cases, the geopressured zones are so consolidated that no sand control is needed. Under such conditions, cemented and perforated casing gives very effective (low restriction) completions.* If sand production is a problem, an artificial gravel pack is often used, as shown in Figure 18. The gravel may be placed either inside or outside the liner. In a section containing sand as well as shale (see Figures 10 and 11), blank liner may be left opposite the shale intervals and intervals of gravel packing used in the sandy intervals.

D. FEASIBILITY OF PRODUCING GAS AND WATER SEPARATELY USING TWO TUBING STRINGS

It had been suggested that the proper way to produce a geopressured brine reservoir is to reduce the pressure, allow gas to segregate at the top of the reservoir, then simultaneously produce brine from the bottom and gas from the top. However, since we have shown that an insignificant amount of gas will segregate vertically, this is not an alternative.

VI. SUMMARY DISCUSSION AND CONCLUSIONS

A. POSSIBILITY OF VERTICAL GAS MOVEMENT IN A GEOPRESSURED RESERVOIR

In the previous sections, gas movement was analyzed for a typical reservoir chosen from the best geopressured brine prospects as determined by geologists at the University of Texas' Bureau of Economic Geology and by the Louisiana Geological Survey after several years of study. For these cases it was concluded that no develop a connected gas saturation of 2-5 percent.

*It is common practice to determine by pressure tests whether any restriction to flow is caused by the completion method and to acidize or "frac" to remove such restriction.

appreciable vertical gas segregation would occur because the amount of gas evolving from solution in the brine is too small to develop a connected gas saturation of 2-5 percent.

B. DISTINCTION FROM MOVEMENT OF CARBON DIOXIDE IN A SOFT DRINK

The analysis showed that a vast difference in scale exists between the solubilities of carbon dioxide and methane in water. As a soft drink is warmed up to room temperature, the volume of carbon dioxide which can evolve is about 70 percent of the liquid volume. In contrast, under geopressured reservoir conditions, the volume of methane which can evolve as the pressure is decreased 2000 psi is only about 0.1 percent of the liquid volume. In a porous medium, these bubbles would never become connected and thus the gas could not flow.

C. CONCLUSIONS

The following conclusions result from this study:

1. Gas evolution from geopressured brines is too small to form a connected gas saturation. Gas will not flow in the reservoir except very near a producing well.
2. Because of this, no gas cap of significant size will ever form.
3. It is not possible to drop the pressure rapidly some distance from a well because of the pressure damping effect of the porous rock in which geopressured brine occurs.
4. If an attempt is made to produce a geopressured reservoir very rapidly the effect will be to diminish any gas movement rather than to enhance it.
5. Current methods of geopressured well completion are the proper ones.

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APPENDIX A

DISCUSSION OF U.S. PATENT 4,149,596 (APRIL 17, 1979) "METHOD FOR RECOVERING GAS FROM SOLUTION IN AQUIFER WATERS"

SUMMARY

The subject patent (see Appendix B) is being discussed in this report because it describes a method for causing gas evolution and obtaining greater gas recovery from geopressured aquifers. According to the patented method, the reservoir must be depleted to such a low pressure that the evolved gas will build-up to a high enough saturation to flow as free gas to the production well. In the following sections, it is shown that the conclusions of this patent are correct in theory. If the geopressured reservoir could be depleted to 500-1000 psi, gas would evolve and flow to the production well along with the water. To deplete the reservoir pressure to such a low level, however, it will be necessary to produce the geopressured brine by artificial lift. An analysis of the various methods of artificial lift shows that none are capable of depleting a deep geopressured reservoir to the required low pressure while still maintaining an economically feasible rate of water and gas production.

THE PATENT

The patent describes depletion of a reservoir at a 15,000' depth, initially at 12,975 psi. The methane in solution is further assumed to be directly proportional to pressure.*

The authors of the patent state that no free gas will flow until the gas saturation reaches a value of 3 percent. This value is reached at a pressure just below 3000 psi. At this point, the evolved free gas is produced along with the water. They state that if the average reservoir pressure could be reduced to 500 psi, some 50 percent of the gas initially dissolved in the brine could (theoretically) be produced.

Note that it is necessary to continually produce water at high rates in order to produce gas at reasonable rates. If water production ceases, the wellbore will fill with water to a height corresponding to the reservoir pressure and no gas will flow out. Later calculations in this appendix show the relationship between the rate of gas flow and the rate of liquid flow.

The patent (correctly) suggests first flowing the well completed in the geopressured formation. As the pressure declines to the neighborhood of hydrostatic pressure (7000 psi), the well will no longer flow. At this point, the patent suggests use of gas lift. Production rates up to 20,000 B/D using gas lift are illustrated. No free gas is produced during this period.

*Although the data of Figure 1 show that this assumption is not strictly correct, its effect on this analysis will be small and will be disregarded.

When the aquifer pressure falls to 3500 psi, gas lift becomes inefficient and submersible pumps must be used.

DEPLETION TO LOW PRESSURE

It is at pressures below 3500 psi that the problem arises. Electric submersible pumps are not capable of continuous service at temperatures greater than about 200°F because of problems with the electric cable. Thus they cannot be run to the depth of 15,000' where the subsurface temperature would be about 250°F-300°F. The maximum practical depth for operation of electric submersible pumps is about 8000 ft. At this depth, the minimum aquifer pressure would be about $(15,000 - 8,000) (0.465) = 3255$ psi. At this pressure, as shown in Table III of the patent, the free gas saturation would be only about 2.5 percent. As this is less than the "critical" gas saturation of 3 percent, no free gas would flow. Thus the only gas produced would have been that in solution in the water under reservoir conditions. In practice, then, it is not possible to deplete this deep geopressured brine reservoir to a pressure where free gas will flow using a submersible pump. Gas lift is also incapable of depletion of a 15,000' brine reservoir below about 3500 psi. The only feasible method of brine production at these low reservoir pressures would be rod pumping.* The maximum rod pumping rate at this depth would be about 200 B/D. In the next section, it is shown that gas production at this rate would be negligible.

RELATIONSHIP TO GAS FLOW TO LIQUID FLOW

As discussed, it is necessary for liquid flow to continue in the formation toward the wellbore in order for gas flow to continue. At low pressure, p , the ratio of gas flow to water flow, is given by:

$$\frac{q_g}{q_w} = \frac{k_{m_g}}{k_{m_w}} \times \frac{p}{14.7} \times \frac{(460 + ^\circ F)}{520}$$

The authors of the patent use such a relationship to calculate the following ratio of gas to water flow rate for their example in Table III. The critical gas saturation of 3 percent was reached at about 3000 psi. No free gas would flow at pressures above this.

<u>PRESSURE</u> <u>PSI</u>	<u>RATIO OF</u> <u>GAS/WATER</u> <u>FLOW RATE</u> <u>SCF/B</u>	<u>GAS RATE</u> <u>FOR 200 B/D</u> <u>WATER RATE</u> <u>SCF/D</u>
3000	-	-
2500	26	5,200
2000	67	13,400
1500	146	29,200
1000	194	39,800
500	212	42,400

*The 15,000' depth stretches the limit even for rod pumping. The author is not aware of any rod pumping below 13,500'.

This gas rate is obviously too low to be of interest. At a price of \$5/MCF, the gross income per day would only be \$65 at 2000 psi. This is less than the well operating cost and is insignificant for a \$5-\$10 million well and facility cost.

As was discussed previously, current submersible pumps cannot be lowered to a depth of 15,000' because of problems with the electric cables at these temperatures. However, even if improved cables were developed, the largest submersible pump available could lift only 3000-4000 B/D of water from this depth. These rates are still too low to give an attractive gas production rate for a 15,000 ft. well since the operator must simultaneously produce, treat, and dispose of 3000-4000 B/D of water.

VERTICAL GAS MIGRATION

The subject patent also discusses vertical gas migration. The patent points out that no such migration will occur until the critical gas saturation of 3 percent is reached at a pressure of about 3000 psi. At low pressures the gas is illustrated to rise to the top of the uniform reservoir and to form a thin gas layer there.

How thick would that layer of gas be? From Table III of the patent it can be calculated that the gas layer would be about 2' thick at a reservoir pressure of 2000 psi if all the gas above the critical gas saturation of 3 percent rose to the top of a 100' thick formation. It would not be possible to drill and complete a "gas" well in this thin low pressure gas layer. If this were attempted, the water would also enter the well. As the water level built up in the wellbore to that corresponding to the reservoir pressure, the well cease to flow and would "die." To produce the gas, it would be necessary to pump the water simultaneously.

APPENDIX B

United States Patent [19]

[11] 4,149,596

Richardson et al.

[45] Apr. 17, 1979

[54] METHOD FOR RECOVERING GAS FROM
SOLUTION IN AQUIFER WATERS[75] Inventors: Joseph G. Richardson; Lawrence D.
Christian, both of Houston, Tex.[73] Assignee: Exxon Production Research
Company, Houston, Tex.

[21] Appl. No.: 905,921

[22] Filed: May 15, 1978

Related U.S. Application Data

[63] Continuation of Ser. No. 786,736, Apr. 11, 1977,
abandoned.[51] Int. Cl.² E21B 43/00

[52] U.S. Cl. 166/267; 166/314

[58] Field of Search 166/267, 314, 268, 263,
166/265, 250

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 Attorney, Agent, or Firm—J. S. Schneider

[57] ABSTRACT

In a method for producing hydrocarbon gas from aquifers which contain gas in water solution, water is produced from wells distributed through the aquifer and solution gases are recovered from the produced water. The aquifer pressure declines as production continues; gas comes out of water solution and a gas phase saturation builds up in the aquifer. When gas saturation exceeds a critical value, gas in gaseous phase flows through the aquifer rock to the producing wells and the ratio of total gas to total water produced increases substantially.

5 Claims, 3 Drawing Figures

FIG. 1.

FIG. 2

FIG. 3.

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METHOD FOR RECOVERING GAS FROM SOLUTION IN AQUIFER WATERS

This is a continuation, of application Ser. No. 786,736, filed Apr. 11, 1977, now abandoned.

BACKGROUND OF THE INVENTION

The present invention concerns a method for producing hydrocarbon gas from subterranean aquifers and, particularly, for producing hydrocarbon gas initially in water solution in the aquifers.

Waters in a large number of aquifers throughout the world contain very large quantities of gas in water solution. Aquifer waters underlying the Texas-Louisiana coastline were estimated to potentially contain about 50 thousand trillion cubic feet of gas. (See "Natural Gas Resources of Geopressed Zones in the Northern Gulf of Mexico Basin" by P. H. Jones presented at the "Forum on Potential Resources of Natural Gas" at Louisiana State University, Baton Rouge, La., on Jan. 15, 1976).

The effect of pressure, temperature and water salinity on solubility of natural gas in water is well known (as, for example, described in an article entitled "pressure-Volume-Temperature and Solubility Relations for Natural Gas-Water Mixtures" by C. R. Dodson and M. B. Standing, Drilling and Production Practice, API, 1944). Of the parameters which affect the amount of gas which can be in water solution pressure is the most important. At depths of about 15,000 feet, "geopressed" aquifers along the Texas-Louisiana Gulf Coast typically have pressure on the order of 13,000 psig and the water contains on the order of 30 standard cubic feet (scf) or more of solution gas per barrel (B).

Aquifer waters can also contain less gas in solution than that corresponding to saturation, in which case they are "undersaturated". It is well known that water resident in certain geological formations in certain geographic areas almost always contains gas in solution closely corresponding to "saturated" conditions.

Aquifer waters with hydrocarbon gas in solution at saturation levels, or near saturation levels, are most suitable for application of the present invention.

SUMMARY OF THE INVENTION

A method for producing hydrocarbon gas from aquifers which contain gas in water solution in which water is produced from wells completed in the aquifer. Continued production of water results in pressure decline causing gas to evolve from the water in the aquifer. That gas migrates to the wells and is produced with the water.

Initially, gas in solution in aquifer water is produced with the water and recovered by surface separation. Continued production causes gas saturation in the aquifer to build up to a level such that gas phase gas flows from the aquifer into wells along with aquifer water. Gas recovered at the surface is the sum of gas in solution in produced water plus produced gas phase gas.

DESCRIPTION OF THE DRAWINGS

FIGS. 1, 2 and 3 illustrate application of the present invention to a typical aquifer.

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DESCRIPTION OF THE PREFERRED EMBODIMENTS

In accordance with the invention, water is produced from wells completed in the aquifer. As water is removed from the aquifer the rock's pore space in which the produced water initially resided is filled by (1) expansion of the aquifer rock, (2) expansion of the water remaining in the aquifer and (3) gas which comes out of water solution. Pressure in the aquifer declines by an amount commensurate with effecting the required expansions.

In FIG. 1 an aquifer 10 is shown in which are completed wells 12, 13 and 14. When production is initiated, aquifer water containing solution gas flows to and is produced from the aquifer wells, as indicated by arrowed lines 11. Gas in solution in the water which enters the wells is produced and recovered by conventional surface gas-water separation techniques.

Intermediate conditions in the aquifer are illustrated in FIG. 2. Continued water production through wells 12, 13 and 14, again indicated by arrowed lines 11, has reduced aquifer pressure. Gas, indicated by globules 15, has evolved from saturation in aquifer water and is accumulating as gas phase saturation in the aquifer rock. Gas phase saturation has not as yet built up to "critical gas saturation" required for gas phase flow through aquifer rock.

In FIG. 3 late (gas phase flow) conditions are illustrated. Production of water containing gas in solution from wells 12, 13 and 14 is continued and reservoir pressure drops to a level well below the initial level, for example, 15 percent of the initial pressure. Water flow to the wells is again indicated by arrowed lines 11. Gas phase gas also flows to the wells, mostly as a thin layer along the top of permeable aquifer rock, as indicated by arrowed lines 16. The thin layer of gas flowing rapidly along the top is replenished by gas segregating to the top of the aquifer by gravity forces, as indicated by arrowed lines 17. Gas saturation in most of the aquifer is slightly above the critical gas saturation at which gas flow commences. Production of gas and water from the aquifer is continued until aquifer pressure becomes so low that gas production is not economic.

In certain structures the dip may be substantial and gravity segregation may greatly aid the flow of the gaseous phase upstructure. If sufficient gas accumulates in structural highs wells may be properly spaced in such structures for producing only gas evolved from water solution and no water.

Tables I and II, below, show calculated gas evolved and buildup of gas saturation with production induced pressure decline in two typical aquifers. The gas saturations were calculated on the basis that no gas phase flow will take place. The Table I results are for a Texas Gulf Coast geopressed aquifer at 15,000 feet depth. The aquifer water initially contains 30 scf/B of solution gas at 12,975 psig pressure. The Table II results are for a Texas Gulf Coast normally pressured aquifer at 6600 feet depth. This aquifer's water initially contains 13.9 scf/B at 3000 psig.

TABLE I

GAS EVOLUTION AND GAS SATURATION BUILDUP AS PRESSURE DECLINES IN A GEOPRESSED SAND

Pressure psi	Solution Gas Evolved, scf/B	S _g ° Fraction
12,975	0	0
12,000	2.3	0.0011

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TABLE I-continued

GAS EVOLUTION AND GAS SATURATION BUILDUP AS PRESSURE DECLINES IN A GEOPRESSURED SAND		
Pressure psi	Solution Gas Evolved, scf/B	S_g^* Fraction
11,000	4.6	0.0023
10,000	6.9	0.0037
9,000	9.2	0.0052
8,000	11.5	0.0070
7,000	13.8	0.0092
6,000	16.1	0.0119
5,000	18.4	0.0155
4,000	20.8	0.0208
3,000	23.1	0.0298
2,000	25.4	0.0481
1,000	27.7	0.1052

*Average gas saturation assuming no gas production

TABLE II

GAS EVOLUTION AND GAS SATURATION BUILDUP AS PRESSURE DECLINES IN A MODERATE DEPTH NORMALLY PRESSURED WATER SAND

Pressure psi	Solution Gas Evolved, scf/B	S_g^* Fraction
3,000	0	0
2,500	2.0	0.0024
2,000	4.0	0.0061
1,500	6.0	0.0122
1,000	8.0	0.0248
750	9.0	0.0374
500	10.0	0.0625
250	11.0	0.136

*Average gas saturation assuming no gas production

Table I and II show that substantial gas saturation will build up if it is not reduced by gas flow from the aquifer. Laboratory data and field performance of a large number of oil fields show that as gas is evolved in rock pore spaces from solution in liquid (or liquids in the case of oil reservoirs containing oil and connate water), the initial gas evolved is held by capillary forces in the larger pore spaces and will not flow with pressure gradients which can practically be effected. As the gas saturation increases, it reaches a "critical" level at which flow will commence. This "critical gas saturation" will be about 3 percent in most aquifer rocks. Tables I and II show that critical gas saturation will be reached at just below 3000 psig in the Table I aquifer and at about 875 psig in the Table II aquifer. When water is produced from aquifers such as those denoted by Tables I and II all but about 1 scf/B of the gas in solution in the aquifer water plus any "gas phase" gas can be recovered by producing the well effluent through a conventional surface gas-liquid separator operated at about 100 psig pressure. Gas from the separator can be utilized in the same manner as gas from conventional oil and gas field operations and water from the separator can be disposed of by using known procedures normal to oil and gas field operations.

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When production from an aquifer is initiated, gas produced per barrel of produced water will correspond to the initial solution level in the aquifer. The produced gas-water ratio will then decline in accordance with the solution ratio in the aquifer (initial solution ratio less gas evolved) until the critical gas saturation is reached in the aquifer rock. After the critical gas saturation is reached both gas phase and water will flow into wells and the produced gas-water ratio will be the sum of gas phase gas entering the well and gas in solution in water entering the well. Gas flow in the aquifer will be greatly aided by the low density and the low viscosity of gas. Gravity forces will cause gas to flow to the top of aquifers where it will accumulate as a thin layer of relatively high saturation. Flow of gas in the thin layer will be greatly aided by the much lower viscosity of gas as compared with water. Production in accordance with the method of this invention will be accomplished most efficiently using wells distributed over the geographic area of the aquifer to minimize pressure differences in the aquifer. Optimum well spacing is dependent on well capacity, well cost, aquifer permeability, aquifer thickness, aquifer porosity, gas content of aquifer water, and several other considerations which will be apparent to those familiar with oil and/or gas production operations.

APPLICATION OF THE METHOD OF THE INVENTION TO A GULF COAST GEOPRESSURED AQUIFER

The production performance expected with depletion of a typical large Gulf Coast geopressured aquifer was calculated using material balance and flow calculation procedures. The aquifer is a water sand at a depth of 15,000 feet. The aquifer area is 300 square miles, thickness of the aquifer averages 300 feet, porosity average is 20 percent and permeability average 100 millidarcies. The aquifer contains 100 billion barrels of water at an initial pressure of 12,975 psi and temperature of 352° F. The water is saturated with hydrocarbon gas at 30 scf/B with the result that gas initially in place is 3 trillion cubic feet. Other properties assumed in the calculations are rock compressibility of 3×10^{-6} psi⁻¹, water compressibility of 3×10^{-6} psi⁻¹, and an initial formation volume factor for water of 1.0411.

The production performance predicted for this geopressured sand is shown in Table III, below. Note that the produced gas-water ratio declines until the gas saturation reaches the critical value of 3 percent at just below 3000 psig. Then the gas-water ratio increases rapidly with continued pressure decline. Production of 16.7 billion barrels of water or 16.7 percent of the water initially in place is required to lower the pressure to 500 psig. At 500 psig the total gas production is almost 1.5 trillion cubic feet (tcf) or 50 percent of the gas initially in place.

TABLE III

PRODUCTION PERFORMANCE PREDICTED FOR GEOPRESSURED WATER SAND

Pressure psi	Gas Saturation Percent	Cumulative Water Production 10 ⁹ Bb	Cumulative Gas Production		Gas Water Ratio	
			10 ⁹ scf	Percent Gas	Incremental scf/B	Cumulative scf/B
				Initially In Place		
12975	0	0	0	0	0	0
12000	0.10	0.672	19.4	0.65	28.9	28.9
10000	0.35	2.072	56.28	1.88	26.3	27.2
8000	0.67	3.526	86.53	2.88	20.8	24.5
6000	1.12	5.098	111.97	3.73	16.2	22.0

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TABLE III-continued

PRODUCTION PERFORMANCE PREDICTED FOR GEOPRESSURED WATER SAND						
Pressure psi	Gas Saturation Percent	Cumulative Water Production 10 ⁹ Bs	Cumulative Gas Production		Gas Water Ratio	
			10 ⁹ scf	Percent Gas Initially In Place	Incremental scf/B	Cumulative scf/B
4000	1.97	7.010	134.07	4.47	11.6	19.1
3000	2.81	8.360	144.99	4.83	8.1	17.3
2500	3.42	9.203	171.89	5.73	31.9	18.7
2000	4.40	10.323	252.00	8.40	71.5	24.4
1500	5.55	11.734	462.54	15.42	149.2	39.4
1000	7.30	13.608	830.21	27.67	196.2	61.0
500	10.40	16.743	1497.6	49.92	212.8	89.4

Initially, water only (gas phase gas will not interfere with water flow) will flow into wells completed in the aquifer. The productivity index of a well in an aquifer with a damage factor of 2 will be 62 B/D/psi. Thus, wells in the aquifer will flow at substantial rates until pressure reaches about 7000 psig. Below 7000 psig lifting will be required. Flowing bottom hole pressures are summarized in Table IV, below, for several gas-water ratios and water production rates. Gas lift can be utilized efficiently to produce water until aquifer pressure approaches 3500 psi. Submersible centrifugal pumps are preferred to lift water at pressures below 3500 psi.

TABLE IV

FLOWING BOTTOM HOLE PRESSURES FOR GAS LIFTING WATER		
Water Rate B/D	Gas-Water Ratio scf/B	Flowing Bottom-Hole Pressure* - psi
4000	250	4189
7000	250	4124
10000	250	4120
15000	250	4147
20000	250	4192
4000	500	3022
7000	500	2915
10000	500	2912
15000	500	2970
20000	500	3090
4000	1000	2162
7000	1000	2052
10000	1000	2062
15000	1000	2150
20000	1000	2402

*Flowing wellhead pressure = 100 psi, depth = 15000 feet. Flow is through 1 9/16 inch ID x 7.625 inch OD annulus.

It has been recognized heretofore that large volumes of gas exist in solution in aquifer waters and it has been proposed in the past that production can be obtained from this resource base by producing aquifer water to the surface and removing the solution gas. It has also been proposed that degassed water be returned to the aquifer to maintain pressure and displace water saturated with gas to the producing wells. No one, however, has heretofore proposed the method of production described and claimed herein in which aquifer pressure

is reduced to levels below those previously contemplated and conditions created wherein gas phase gas will flow to the wells completed in the aquifer. In this manner gas which was originally in solution in all of the water in the aquifer is produced whereas the gas production heretofore proposed would all come from produced water only. Application of the method of the invention will result in production of a larger quantity of gas per barrel of water produced and thereby the cost per unit of gas produced will be substantially lower.

Changes and modifications may be made in the illustrative embodiments of the invention shown and described herein without departing from the scope of the invention as defined in the appended claims.

Having fully described the nature, operation, method, advantages and objects of our invention we claim:

1. A method for recovering gas from solution in aquifer waters of a normally pressured aquifer comprising the steps of:

- 35 lifting water from wells completed in said normally pressured aquifer until the pressure in said aquifer is reduced sufficiently to cause gas initially in solution in said aquifer to become mobile and to flow as a gaseous phase in said aquifer, said wells being producible only by lifting;
- 40 continuing to produce water from said wells to cause gas saturation to build up in excess of that required for gas to flow in gaseous phase to said wells; and producing said gaseous phase which has evolved from said water in said aquifer from said wells.

2. A method as recited in claim 1 in which substantially more gaseous phase gas is produced than the gas in solution in said water.

3. A method as recited in claim 2 in which said produced gas is separated from said water at the surface.

4. A method as recited in claim 3 in which substantially the only gas produced is that gas in solution in said water and said gaseous phase evolved from said water.

5. A method as recited in claim 1 including producing only said gaseous phase gas from one or more of said wells.

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FIGURE 1
SOLUBILITY OF METHANE IN FRESH WATER

FIGURE 2 EFFECT OF SALINITY ON THE AMOUNT OF GAS IN SOLUTION
WHEN BRINE IS FULLY SATURATED WITH GAS

(after DODSON and STANDING)

FIGURE 3

SOLUBILITY OF NITROGEN, METHANE, AND CARBON DIOXIDE IN WATER

FIGURE 4

GAS AND WATER RELATIVE PERMEABILITY CURVES

FIGURE 5
GEOPRESSURED ZONES - NORTHERN GULF OF MEXICO

FIGURE 6
GEOPRESSURED ZONES - NORTHERN GULF OF MEXICO

FIGURE 7

DEPOSITIONAL STYLE OF TERTIARY STRATA
ALONG THE TEXAS GULF COAST

FIGURE 8

FRIO GEOTHERMAL FAIRWAYS, DEPOSITIONAL MODELS, AND RESERVOIR QUALITY

FIGURE 10 - SAND DISTRIBUTION FROM ELECTRICAL LOG OF WELL FROM THE BAER RANCH FIELD,
MATAGORDA FAIRWAY

FIGURE 11 - LOG AND CORE ANALYSIS RESULTS FOR WELL IN BRAZORIA GEOPRESSURED FAIRWAY

FIGURE 12 - SCHEMATIC GAS MIGRATION PATHS AROUND SHALE LAYERS

FIGURE 13

ELECTRICAL LOG, CORE DESCRIPTION, AND CORE ANALYSIS FROM A SANDSTONE UNIT IN THE CORPUS CHRISTI FAIRWAY

SHELL NO. 1 STATE TRACT 346 18-23-6

FIGURE 14

PRESSURE DISTRIBUTION IN A RESERVOIR

FIGURE 16
SOLUBILITY OF METHANE IN BRINE

FIGURE 17

WIRE WRAPPED SCREEN

FIGURE 18

(from HUBER, ALLEN & ABENDROTH, 1960)

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