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NATURAL GAS CONTENT OF GEOPRESSURED AQUIFERS

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Abstract

It is hypothesized that free, but immobile, natural gas is trapped in pores in geopressured aquifers and that this gas becomes mobile as aquifer pressure is reduced by water production. Computer simulation reveals this hypothesis is a plausible explanation for the high gas/water ratio observed from the No. 1 sand in the Edna Delcambre No. 1 well.

In this Delcambre well test, the gas/water ratio increased from the solution gas value of less than 20 SCF/bbl to more than 50 SCF/bbl during production of 32,000 barrels of water in 10 days. Bottom hole pressure was reduced from 10,846 to 9,905 psia.

The computer simulation reveals that such increased gas production requires relative permeability to gas (k_{rg}) increase from less than 10^{-4} to about 10^{-3} due to a decrease in fractional water saturation of pores (S_w) of only about 0.001. Further, assuming drainage relative permeabilities are as calculated by the method of A.T. Corey[1], initial gas saturation of pores must be greater than 0.065.

Means for achieving these initial conditions during geological time will be qualitatively discussed, and the effect of trapped gas upon long-term production will be described.

DISCLAIMER

Two Phase Flow in Rock

The flow of fluids through reservoir rock involves tortuous paths through an enormous number of interconnected pores and channels. These small pores and channels have a broad distribution in sizes and are interconnected to provide an incredibly complex network of flow paths. The trajectory of a molecule of fluid moving through the rock is like that of a mouse moving through a maze — there are numerous false starts and abrupt changes in direction.

When a single fluid is present, movement through the rock under conditions appropriate to producing water from geopressured aquifers is adequately described by Darcy's law. For liquid movement through a core sample, that law is

$$q = \frac{kA}{\mu}\frac{(P_1 - P_2)}{L} \qquad (1)$$

where q = flow rate

k = permeability

A = cross sectional area of the core

μ = viscosity of the liquid

P_1 = Pressure at the upstream end of the core

P_2 = Pressure at the downstream end of the core

L = length of the core

The value of permeability for a single fluid is dependent only on the rock and is independent of whether the fluid is water, oil, or gas. Of course, for gas the compressibility must be taken into account, so that the term $(P_1 - P_2)$ in equation (1) becomes $\frac{(P_1^2 - P_2^2)}{2P_b}$, where P_b is the pressure base for gas volume measurement.

However, when two phases, such as gas and water, are present, each fluid phase interferes with the other's movement. This becomes apparent when one recognizes that the pores and channels in the rock have a broad distribution of sizes and that surface tension forces spread the water until all surfaces of the pores and channels are water wet. The result is that the tiniest pores and channels will be completely water filled and therefore not available for gas flow. On the other hand, the largest pores and channels will have a thin film of water on all rock surfaces, but gas will be the continuous fluid phase moving through them.

Ignoring other complexities, such as the reduction of sizes of pores and channels as reservoir pressure is reduced by production, the interference between gas and water flow is mathematically described by substituting effective permeability (k_{eff}) for the single-phase permeability in Darcy's law. Effective permeability is simply the single-phase permeability (k) multiplied by the relative permeability (k_{rg} or k_{rw}) for the gas or water phase. As illustrated in Figure 1, the magnitude of relative permeability is always less than or equal to one and, when both phases are mobile, the sum of relative permeabilities to gas and water is always less than one.

The shape of the relative permeability curves is dependent upon saturation history. If gas pressure is applied to one end of a water-

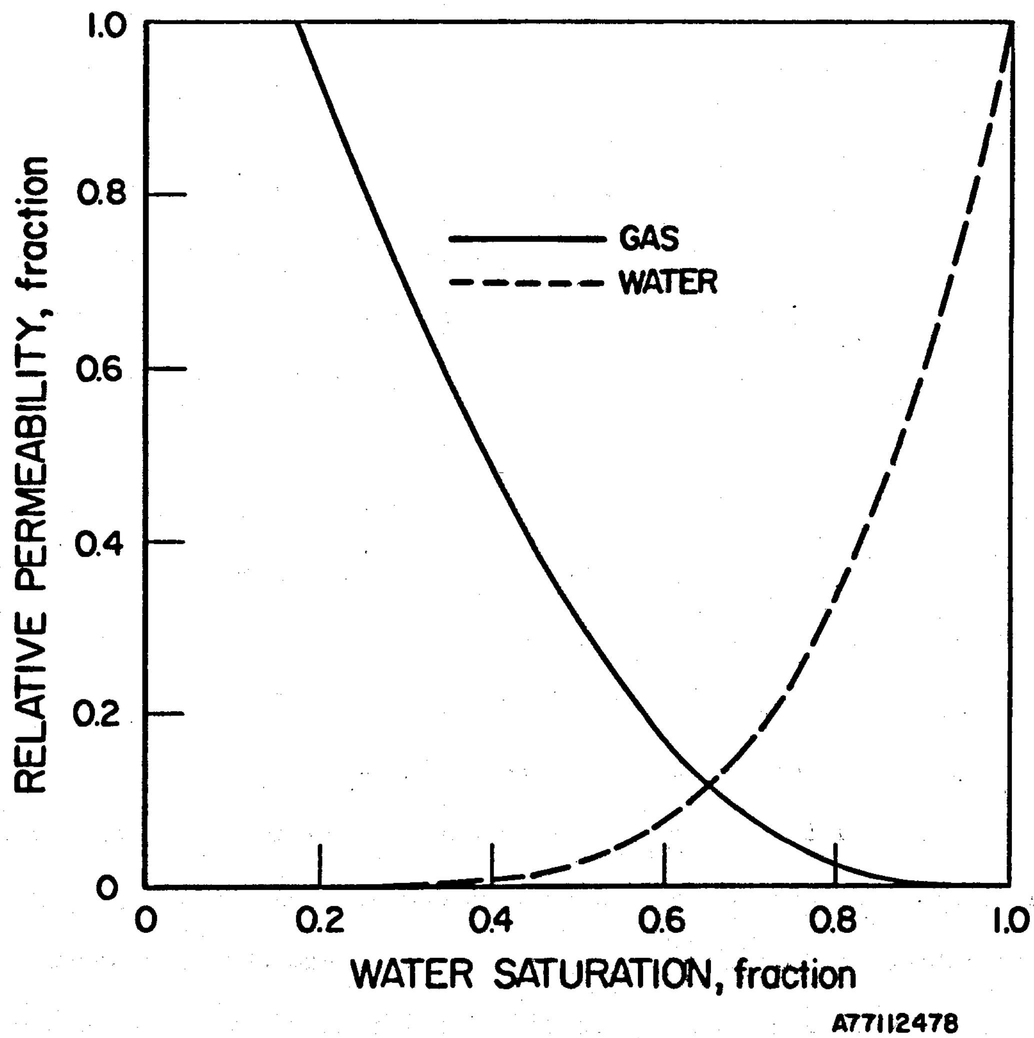

Figure 1. CALCULATED DRAINAGE RELATIVE PERMEABILITIES FOR IRREDUCIBLE WATER SATURATION OF 0.17

saturated core, it will first break through the path of largest interconnected pores and channels. Continuing gas flow will then displace water from progressively smaller paths until the only water remaining is the thin film due to surface tension. This irreducible water saturation of 20 to 25 percent is characteristic of gas caps above geopressured aquifers.

Conversely, if water pressure is applied to the core, initially at irreducible water saturation, the water will most rapidly displace gas from the path of largest connected pores and channels. Gas-filled pores of intermediate size, or "dead ends," will be bypassed, and the gas therein will be trapped. If water pressure is increased, the small bubbles of trapped gas will be compressed and farther isolated from one another. On the other hand, if pore pressure is reduced, the minute trapped gas bubbles will expand and expel water until paths for gas flow are created. This results in a "waterflood cutoff" in relative permeability to gas, as shown in Figure 2.

This trapping of hydrocarbons due to relative permeability effects during waterflood was extensively studied during the early 1950's. The subject is comprehensively treated in textbooks on reservoir engineering, and we are all aware that sufficient oil remains in the ground after waterflooding for elaborate tertiary oil recovery technologies to be warranted. Similar trapping of 15 to 50 percent of natural gas was unequivocably demonstrated in the excellent work by T.M. Geffen, D.R. Parrish, G.W. Hayes and R.A. Morse in 1952.[2]

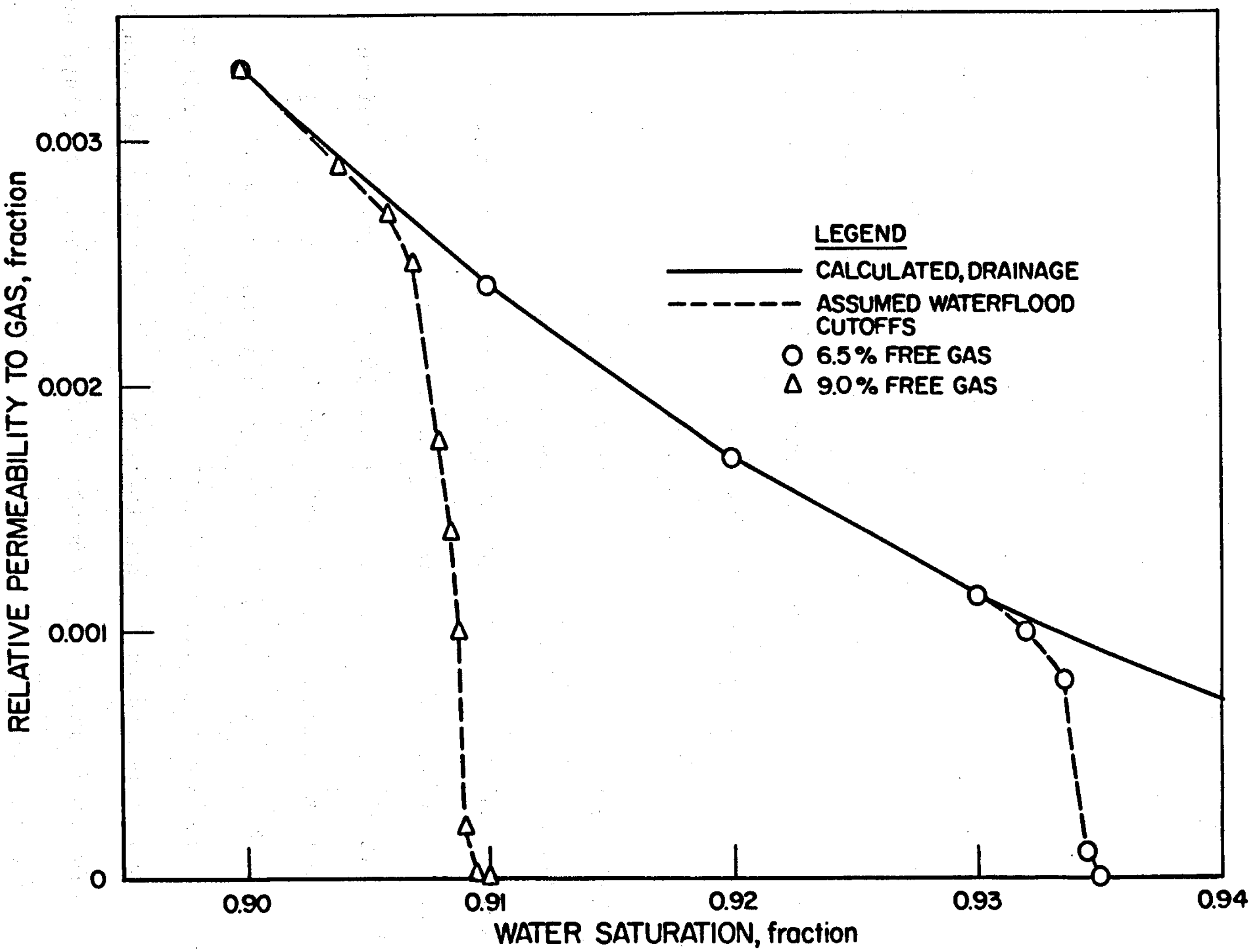

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Figure 2. WATERFLOOD CUTOFFS OF CALCULATED DRAINAGE RELATIVE PERMEABILITY TO GAS

The trapping of natural gas during waterflood has been clearly recognized in operation of aquifer storage facilities for natural gas. About half of the natural gas placed in aquifer storage is recognized to be nonrecoverable, and its cost is treated as capital investment in economic analysis of storage facilities.

More recently, it has been shown that substantial expenditures to minimize the pressure of trapped gas are warranted in producing gas reservoirs that have a strong water drive.[3] In addition, patents[4] have been awarded for enhancing production from waterdrive geopressured gas caps by using high-rate water production to decrease pore pressure so that expansion of trapped gas will lead to its production.

Trapping of Natural Gas in Geopressured Aquifers

The 1975 paper by P.H. Jones[5] provides a detailed scenario for the geological history of Gulf Coast geopressured reservoirs. In brief terms, this history consists of the following:

1) Isolation of permeable sandstones by growth faults before the depth of burial is sufficient for dewatering of clays or breakdown of organic matter to form natural gas.
2) Migration of water and dissolved hydrocarbons from shale to isolated sandstones when the depth of burial is great enough for pressure and temperature to cause dewatering of clays and generation of light hydrocarbons.

3) Increasing pore pressure in the sandstones as fluids from the shales accumulate in the pores.

4) When pore pressure in the sandstones reaches lithostatic, growth faults are forced open and fluids leak off to shallower depth.

5) When leakage has dropped pressure sufficiently, the growth faults close and pore pressure again increases due to continuing fluid migration from adjacent shales.

It is hypothesized that iteration of the last two steps in this scenario provides a mechanism for trapping of free natural gas in pores in geopressured aquifers. In qualitative terms, this occurs as follows:

1) When isolated by growth faults, the pores in the sandstone are filled with water.

2) When temperature and pressure are sufficient, water saturated with natural gas migrates from the shales to the pores in the sandstone until pressure reaches lithostatic. At this point in the first pressure cycle, there is no free natural gas in the pores.

3) When leakage through growth faults commences, pore pressure in the sandstone begins to decrease. This decreasing pore pressure is accompanied by dissolution of some of the natural gas dissolved in water at higher pressure. During this first leakoff, the quantity of natural gas liberated is so small that free natural gas occupies less than one percent of the

pore space. Relative permeability to gas remains effectively zero.

4) After leakage terminates, continuing migration of hydrocarbon saturated water from adjacent shales to the isolated sandstone again builds up pore pressure in the sandstone. However, this new water is saturated at the higher pressure of the shales, so the tiny bubbles of gas liberated during the growth fault leakage will not be redissolved. They will remain trapped, with the relative permeability curve changing to that for a waterflood.

5) During each subsequent cycle of pressure buildup and leakage through faults, additional free natural gas is liberated, and the volume of trapped natural gas increases by a fraction of one percent of the pore volume. On each cycle, the sharp cutoff of waterflood relative permeability to gas moves to lower water saturation.

6) This process of incrementally decreasing water saturation of pores on each growth fault leakage cycle continues until relative permeability to gas at the times of minimum pressure is great enough for gas cap development or gas production through the growth fault leakage to equal the amount of gas entering the sandstone from the shale on each pressure buildup cycle.

Preliminary production test data from the Edna Delcambre et al. No. 1 well has been examined as a test of this hypothesized trapping of natural gas in geopressured aquifers. Details of that examination and projections of production with trapped gas taken into account constitute the remainder of this paper.

History Match to Bottom Hole Pressure

The Edna Delcambre et al. No. 1 well production test data in the public domain at the time this work was performed are shown in Tables 1 and 2. Both wireline log data[6] and the high initial gas production in Table 1 reveal that a small gas cap was present in the first sandstone tested (No. 3 sand at a depth of 12,900 feet). The leveling off at a gas/water ratio several times that for solubility of gas in water under reservoir conditions was exciting in relation to this author's prior examination of implications of the hypothesized trapping of natural gas. However, computer modeling of production was not attempted due to the additional complication of the gas cap.

In contrast, the data for the No. 1 sand at about 12,600 feet (Table 2) reveals that the initial gas/water ratio was very near that expected for reservoir conditions. Thus, if a gas cap exists, it is not present at the location of the perforated interval.

Due to the minimal data available, computer simulation was limited to use of Intercomp's Radial Coning Model with a single vertical zone used to describe the producing interval. Solubility of natural gas in water was included by assigning physical properties of water, including Cubbertson McKetta solubility data,[7] to what is normally the oil phase in the computer simulation. The computer program's water

Table 1. FLOW DATA, SAND NO. 3

Duration of Flow Test, hr	Minimum Bottom Hole Pressure	Average Water Production Rate, bbl/day	Average Gas Production Rate, 1000 CF/day	Gas/Water Production Ratio, SCF/bbl
18	--	2,608	573.3	219.84
25.5	10,721	2,602	578.8	222.42
24	8,439	5,460	309	56.59
3	8,789	8,328	352	42.27
14*	8,851	8,628	529.7	61.39
32.5	--	3,738.8	214.9	57.48
1.5	--	5,744	304	52.92
94	10,232	3,252.5	236.9	72.85
7.25†	--	3,343.4	149	44.55
	Maximum Rate	10,333	260	25.16

* Produced sand.

† Sand found over one-half of perforations after last test.

Table 2. FLOW DATA, SAND NO. 1

Duration of Flow Test	Minimum Bottom Hole Pressure, psia	Average Water Production Rate, bbl/day	Average Gas Production Rate, 1000 CF/day	Gas/Water Production Ratio, SCF/bbl
48 hr	10,601.05	1,165	19.61	16.84
48 hr	10,406.68	2,040	38.13	18.6
48 hr	10,215.81	3,146	60.47	19.2
48 hr	10,073	4,752	130.80	27.5
39 hr	9,905	6,007	311	51.9
20 hr 34 min	9,835	7,599	333.24	43.8
20 hr 19 min	9,748	8,479	544.4	64.2
18 hr 26 min	9,688	9,691	613.1	60.8
4 hr 18 min	--	11,399	550.27	47.9
7 hr 18 min	--	12,339	765.09	62
	Maximum Rate Conditions	12,653	710.83	56.17

phase was assigned an artificially high density and placed in a zone with zero permeability below the perforated interval.

Efforts to history match the bottom hole pressure using the flow rates in Table 2 were limited to the first 231 hours of production. This is due to the authors' impression that production was continuous over that time period, but that the well was shut-in for several days between the fifth and sixth lines of data in the table.

A total of 18 computer runs were made in the effort to obtain a history match to bottom hole pressure. Parameters varied were permeability, drainage radius, compression drive, amount of trapped gas, radius dependence of permeability, and steepness of the cutoff in relative permeability to gas. It was found that a choice had to be made between matching the bottom hole pressure for the first 4 to 6 days or at the end of 231 hours (9.63 days) of testing. In all cases, the calculated pressure drop for steps in production rates from 3146 barrels per day (bpd) to 4752 bpd and then 6007 bpd were greater than the reported changes in bottom hole pressure for those steps.

Since expansion and production of trapped natural gas is strongly dependent upon the drop in pore pressure, reservoir parameters giving a total pressure drop similar to that observed after 231 hours of production were adopted for attempts to model the increase in gas/water ratio observed. Values used for the results reported herein are set forth in Table 3. The reported and calculated bottom hole pressures are shown in Figure 3.

Table 3. RESERVOIR PARAMETERS

Identical values were used in both reported simulations for the following reservoir parameters:

Reservoir Pressure	10,882 psi
Reservoir Temperature	240°F
Porosity	20 percent
Drainage Radius	6,661 feet
Wellbore Radius	1.0 feet
Thickness	31 feet
Rock Compression Drive	4.0×10^{-6} vol/vol-psi
Water Compressibility	3.84×10^{-6} vol/vol-psi
Bubble Point	10,882 psi

Additional reservoir parameters for each case are as follows:

Initial Gas Saturation	6.5 percent	9.0 percent
Single Phase Permeability	119.8 millidarcies	130.7 millidarcies
Permeability at Initial Saturation	85.8 millidarcies	82.6 millidarcies
Initial Water in Place	3.22×10^8 bbl	3.178×10^8 bbl
Initial Gas in Solution	7.728 billion CF	7.628 billion CF
Initial Trapped Gas	23.118 billion CF	32.010 billion CF
Total Gas in Place	30.846 billion CF	39.638 billion CF

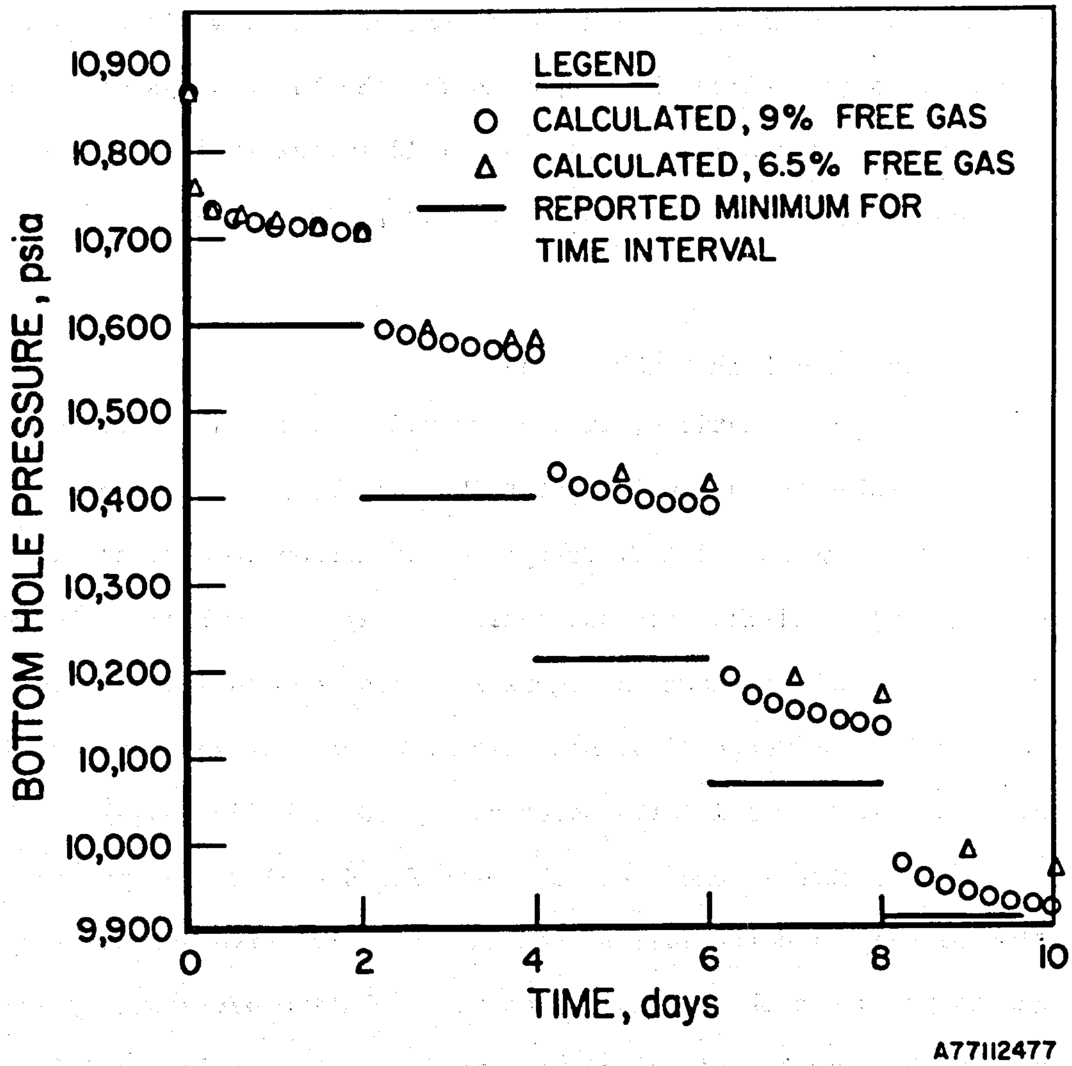

Figure 3. HISTORY MATCH OF BOTTOM HOLE PRESSURE

The discrepancy between reported and calculated bottom hole pressures warrants careful examination when more detailed reporting of production data occurs. This is because obvious considerations such as drainage area boundary effects or formation damage would cause a more rapid pressure decline than reported for the later steps of increasing flow rate. One possibility is that fluid influx from outside the assumed height of 31 feet contributes to production by vertical fluid flow.

Test of the Trapped Gas Hypothesis

For all calculations, it was assumed that the drainage relative permeabilities to gas and to water (k_{rg} and k_{rw}) had the shape calculated by the method of A.T. Corey[1] for an irreducible water saturation of 0.17 and a critical gas saturation of zero. Resultant relative permeabilities are shown in Figure 1. These curves describe the water saturation dependence of permeability when natural gas pressure displaces water from initially water saturated rock (drainage).

It was then assumed that the waterflood cycles over geological time had modified the tail of the curve for relative permeability to gas to produce a sharp cutoff such that relative permeability became zero with a small residual gas saturation. The cutoffs used for the results presented herein are shown in Figure 2. The points connected by straight line segments reflect the values actually used in the computer simulation.

Calculated and reported time histories for the produced gas/water ratio are shown in Figure 4. The calculated values shown are actual numbers from computer printouts connected by straight lines. This plotting procedure was used because results suggest that more frequent printouts are required to portray the transients in gas/water ratio that are triggered by each step in production rate.

For the relative permeability cutoff to achieve 6.5% of the pore space occupied by free natural gas, calculated water saturation in zones near the wellbore had been reduced from the initial 0.9350 to 0.9340 at the time of maximum gas/water ratio (days 9 and 10). Figure 2 reveals that the corresponding relative permeability to gas is about 4.3×10^{-4}. For a water saturation of 0.9340, the ratio of assumed relative permeability to gas to that for water (k_{rg}/k_{rw}) is 0.60×10^{-3}. At the peak calculated gas/water ratio for nine percent trapped gas (50 SCF/bbl at 8.75 to 9 days), calculated water saturation near the wellbore had been reduced from the initial 0.9100 to 0.9089. From Figure 2, the correspondingly relative permeability to gas is about 6.0×10^{-4}. The ratio of relative permeabilities to gas and to water is about 1.0×10^{-3}.

Neither calculated peak in the gas/water ratio after the water production rate was increased to 6007 bbl/day during the eighth day was as great as reported. This suggests that the actual ratio of relative permeability for gas to that for water must be greater than 1.0×10^{-3} for the modest reduction in water saturation near the wellbore caused by producing about 28,000 gallons of water in about 9 days.

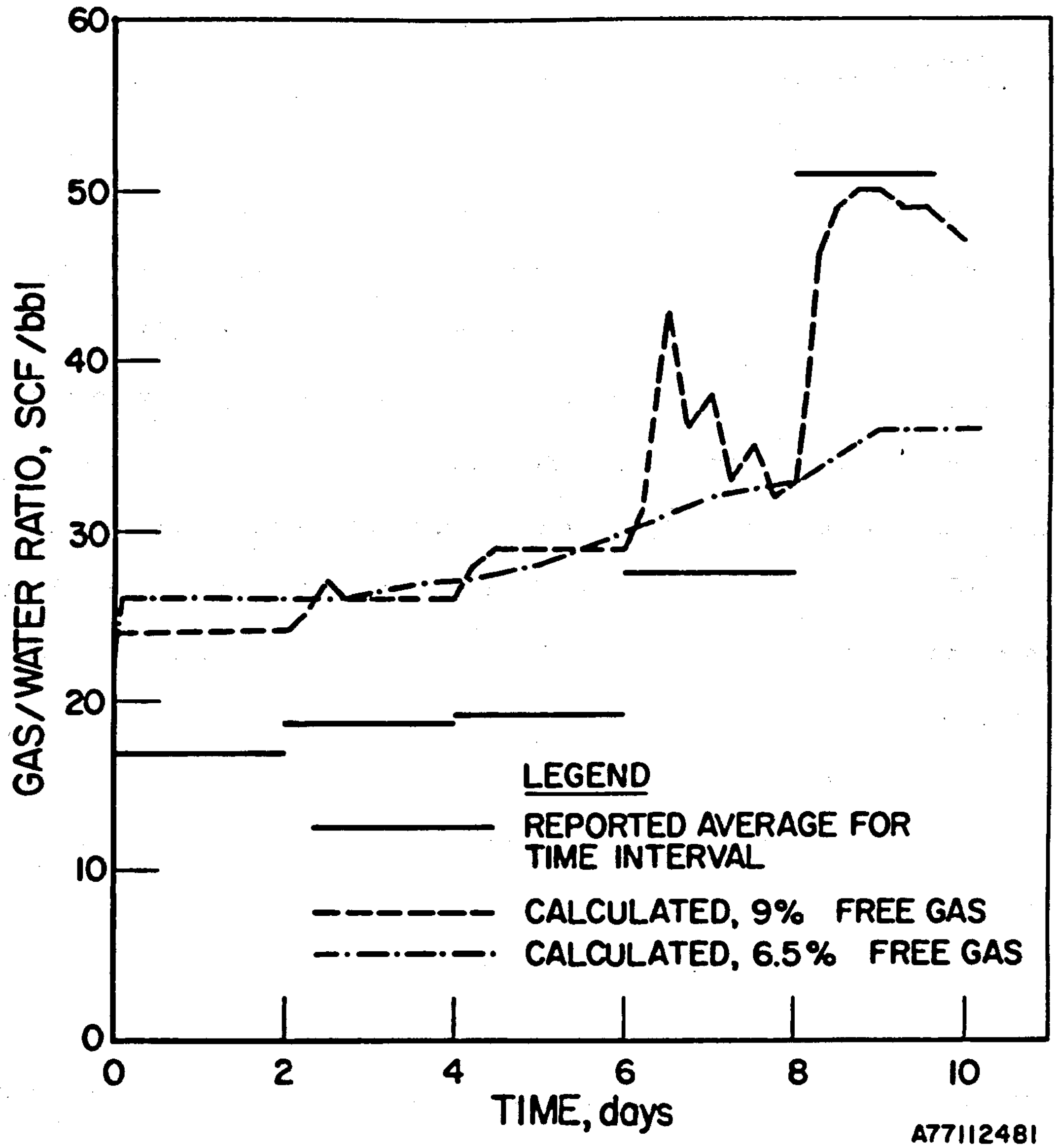

Figure 4. HISTORY MATCH OF GAS/WATER RATIO

_If_ the drainage relative permeability curves based on Corey's[1] analytical approximation are indeed valid for these low gas saturations, the maximum possible ratio of gas to water relative permeabilities for a water saturation of 0.934 is 1.345×10^{-3}. Since a ratio of more than 1.0×10^{-3} is required to match reported gas production, it appears that free gas present in pores must exceed about 6.5 percent of pore volume.

_If_ valid for geopressured reservoirs in general, this conclusion is of great importance in relation to the resource base of natural gas in geopressured reservoirs. The quantity of free natural gas in 6.5 percent of pore volume for the reservoir parameters in Table 3 is 23.118 billion CF (BCF). Assuming that an additional 18 SCF/bbl is in solution, dissolved gas totals 5.796 BCF. Thus, the total resource base of natural gas would be 28.91 BCF, or five times the resource base in the form of natural gas in solution.

The exciting implications of this additional natural gas in terms of production of both geothermal brines and natural gas are examined below.

Effects of Trapped Gas Upon Long-Term Production

Projections of long-term production were made for the relative permeability cutoffs shown in Figure 2. For these projections, the water production rate was assumed to remain constant at 6007 bpd after day 10. The resulting cumulative gas production and times at which flowing bottom hole pressure is reduced to hydrostatic for brine (5850 psi)

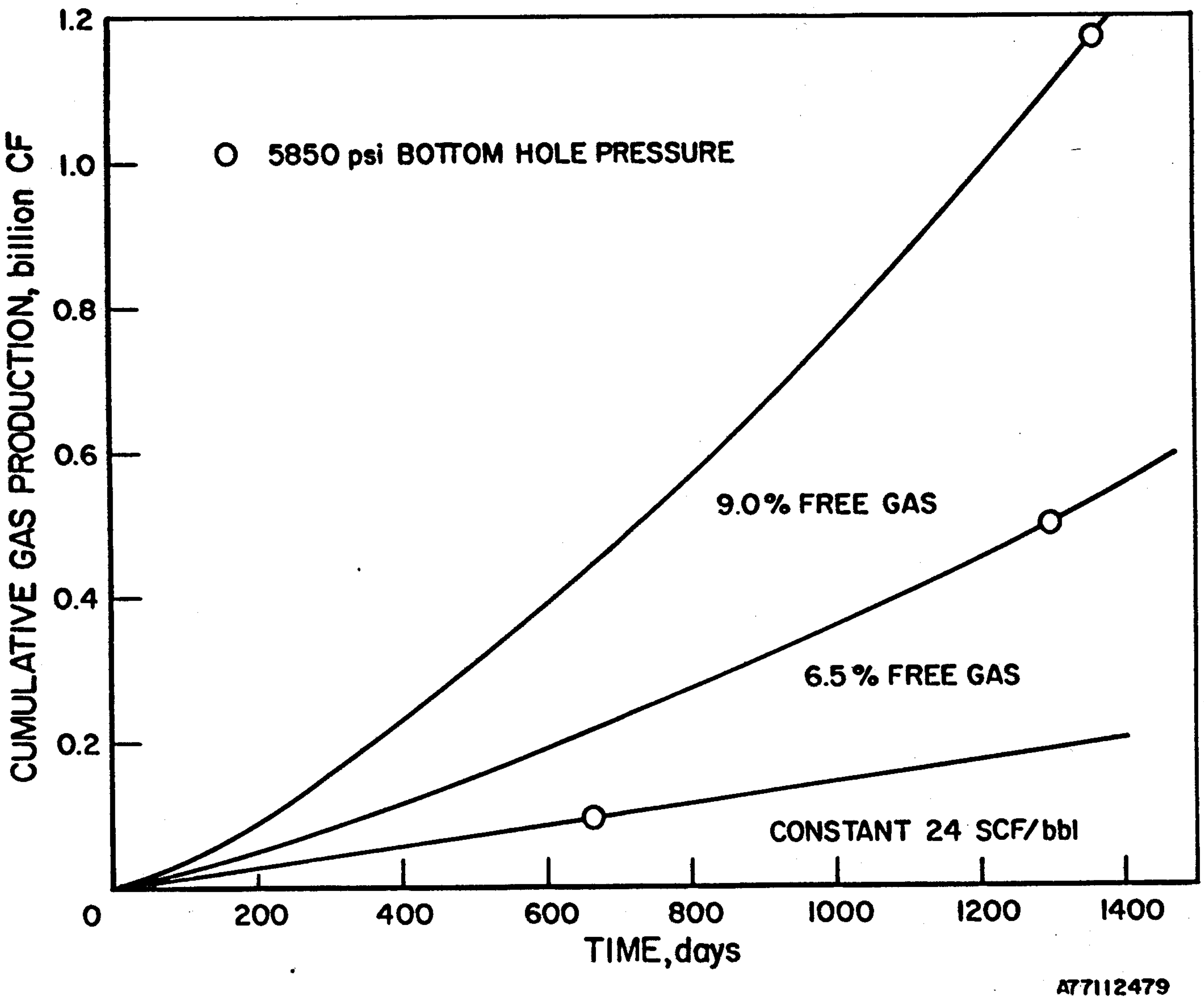

Figure 5. PROJECTED NATURAL GAS PRODUCTION FROM SAND NO. 1

are shown in Figure 5. The case where produced gas/water ratio remains at the assumed 24 SCF/bbl and the sum of rock and water compression drives is 7.84 X 10^{-6} vol/vol-psi is also shown.

The presence of 6.5 to 9.0 percent trapped natural gas in pores doubles the length of time required for bottom hole pressure to be reduced to hydrostatic (5850 psi). This corresponds to more than doubling the length of time that the well would be capable of sustaining a constant water production rate of 6007 bbl/day. Definition of the duration of constant water production rate requires consideration of both friction loss in tubular goods and the gas lift due to the 100 to 200 SCF/bbl of natural gas in the produced stream when bottom hole pressure is hydrostatic for reservoir depth. Since the calculated gas/water ratio is rapidly increasing, the gas lift may permit maintaining a constant water production rate for substantially longer than twice the time possible if no free gas is present in reservoir pores.

As shown in Figure 5, for 6.5 to 9.0 percent of pore space occupied by trapped natural gas, cumulative gas production when reservoir pressure has been reduced to hydrostatic is projected to be five to twelve times as great as would occur with no free gas trapped in pores. The calculated produced gas/water ratio when bottom hole pressure reaches hydrostatic is about 86 SCF/bbl for 6.5 percent free gas and 205 SCF/bbl for 9.0 percent free gas. In both cases, the ratio is rapidly increasing with time. Therefore, gas lift of water in the wellbore will be an important factor in estimating well lifetime and ultimate production.

Conclusions

1) The analysis presented herein reveals that trapping of natural gas by a sharp relative permeability cutoff due to periodic waterfloods over geological time is a credible hypothesis when tested against the limited preliminary production test data from the No. 1 sand in the Edna Delcambre et al. No. 1 well.

2) The required relative permeability cutoff is very sharp. Relative permeability to gas must increase from less than 10^{-4} to more than 10^{-3} for a fractional change in water saturation of only about 0.001.

3) Assuming that drainage relative permeability calculated by the method of A.T. Corey provides an upper limit for the cutoff in relative permeability to gas, the minimum fraction of aquifer pore volume occupied by trapped natural gas is 6.5 percent. This corresponds to total gas in place being five times as great as the quantity in solution in the reservoir brine.

4) The trapped natural gas in the No. 1 sandstone is projected to more than double the length of time that water can be produced at constant rate. Producible natural gas will be more than five times that from a gas-saturated aquifer containing no free natural gas.

It is emphasized that extensive additional research is essential to determine whether the hypotheses and assumptions implicit in this research are truly descriptive of nature. Some topics requiring research were identified by this author in September 1977.[8] These are as follows:

1. Quantitative determination of compression and compaction drives plus their dependence upon pore pressure.
2. Definition of the reduction in permeability due to the increasing stress on the rock matrix as pore pressure is reduced by production.
3. Measurement of relative permeabilities to gas and to water for the high water saturations critical to the analyses herein.

Several additional research topics must be addressed before jumping to the conclusion that as much as a billion cubic feet of natural gas can be produced in a few years from the geopressured sandstone volume of only 0.029 cubic miles assumed herein. These include —

1. The effect of gas in solution upon compressibility of reservoir brine. The relatively high value of 3.84×10^{-6} vol/vol-psi used herein is based upon extrapolation of the limited existing data for lower pressures,
2. The effect of gas in solution upon viscosity of reservoir brine. The value of 0.36 cp used for this paper is representative of gas-free water containing 10% NaCl at a temperature of $240^{o}F$ and pressure of 10,000 psi.

3. Relative permeability trapping of natural gas in the deepest portions of aquifers. Since the Edna Delcambre et al. No. 1 well was originally drilled for natural gas, it probably penetrates a shallow portion of the aquifer most favorable to trapping natural gas.

Acknowledgments

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