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Progress Report

NEW CONCEPTS ON UNDERGROUND STORAGE

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INTRODUCTION

During the Spring of 1963, under the sponsorship of the American Gas Association, a research project was initiated at the University of Michigan to "... formulate and explore new concepts on underground storage."

The prolific growth experienced during the last decade on production, pipelining, storage and consumption of natural gas has justified recent deployment of significant research effort on various aspects of natural gas storage. The AGA Project NO 31 concluded during 1963 had as its main objective understanding of the "... movement of water in contact with natural gas." Because practically all producing or underground storage reservoirs are subject to some degree of water drive, the extent and the nature of water movement is of utmost importance if accurate, reliable predictions are desired on the behavior of gas storage bubble. The AGA Monograph on "The Movement of Underground Water in Contact with Natural Gas" documents the final results on Project NO 31 where practical solutions to many gas storage problems were presented in minute detail. While the AGA Project NO 31 basically implemented engineering research effort on macro-reservoir scale, a cognate research program sponsored by the Michigan Gas Association and still in progress at the University is directed toward the physics of microscopic phenomena where natural gas and water displace one another in a porous matrix. Both of these research programs provided definitive, quantitative answers to many problems while uncovering perhaps an equal number of problems yet to be solved.

The original underground storage projects were located in depleted gas or oil reservoirs, formations with well proved ability to retain hydrocarbons under pressure. In storing the gas in such natural reservoirs a very significant breakthrough was made when the practice of "overpressuring" became a practical reality. The injection of gas in these formations to pressures above the discovery resulted in large increases of the storage capacity of existing reservoirs.

Ever increasing developments in production, processing and consumption of natural gas continues to result in expansion of marketing areas, particularly near highly populated industrial centers. Many such areas located in the Northeast and North Central United States and Eastern Canada have little proved natural gas reserves. These areas are normally supplied by long-distance pipelines, some as long as 2000 miles from reserves located in Southwestern United States and Western Canada. Economic considerations in the operation of such pipelines require that their service load must be maintained as continuously near their design capacity as possible if low transportation cost is to be realized. In order to keep these pipelines full and in operation during the low domestic demand in summer the gas must be stored somewhere underground during the summer in areas where depleted gas or oil reservoirs are not generally available. During the last decade this too became a reality in the development of "aquifer storage" where the pore volume for the storage was created through expulsion of water from its native formation by injection of gas into aquifers at pressures above the discovery pressure. A second breakthrough in gas storage was made when the movement of water in contact with natural gas was

quantitatively related to the performance of the gas storage bubble. Through successful applications of digital computing techniques significant new contributions were made to our understanding of the behavior of gas storage reservoirs subject to water drive. Here too, along with new data, solutions, and contributions, a large number of new problems were uncovered. The physical processes leading to the development of the storage bubble during early stages of gas injection, mechanical and flow properties of caprocks related to leakage or breakage, nature of threshold pressure phenomena, instability and hysteresis of gas-water displacement phenomena are but a few of such typical problems uncovered during recent research work.

While the expanding gas market does and will continue to foster the search for new gas reserves in areas of acute need, it was recognized that development of new ideas, new techniques and new concepts for gas storage must be explored if the industry is to meet the long range necessities indicated by the future expansion of the gas market. During the initiation of this research project it was further recognized that there are vast areas in the United States and Canada where sedimentary rocks do not exist.

There were practically no underground storage reservoirs for natural gas in the forties, depleted gas or oil field storage since the fifties and aquifer storage during the last decade. At present, aquifer storage, if and when operated successfully, appears to be the most economical method for areas devoid of depleted oil or gas fields. It is well known, on the other hand, that the success of aquifer storage depends critically on the presence of suitable subsurface geology. Sufficient porosity, adequate permeability and satisfactory caprock and structural closure are the prime requirements

for such storage. Even in areas where sedimentary rocks abound the above factors do not always simultaneously co-exist. Sufficient porosity and permeability but lack of adequate closure, adequate structure but leaky caprock, semi-open, saddle type structure or no anticline at all are typical examples of such imperfect conditions. The storage of gas in such strata requires new techniques, new concepts which have not been suggested or adequately explored to date.

The basic objective of this research project is to formulate and explore "New Concepts on Underground Storage." It must be clear from the preceding review and introduction that a study of this type should be approached by a review of all existing methods of underground storage as related to geographic, geologic or geophysical conditions to which they are best suited. This report combines presentation of such a review along with new ideas and concepts suggested and systematically analyzed during the first eight months of the research project. The evaluation of new techniques and concepts is of course not final but in progress at this writing.

It might be appropriate at this point to list areas now under study and where potentially practical and economical new concepts and techniques are being developed.

1. Storage in semi-open or fully open structures where the movement of gas may be controlled through application of hydraulic control or soil impermeation by injection of grouts.
2. Storage of gas in non-porous void continuum such as salt caverns, mine shafts, etc.
3. Detection and remedy of leaks from aquifer storage.

4. Novel concepts in gas storage - surface sands, gravel pits, underwater storage.
5. Underground storage through soil impermeation by fracturing and grouting; design of artificial caps and storage bubble boundaries.

1. IMPERMEATION OF UNDERGROUND FORMATIONS

A large number of practical engineering problems encountered in subsurface construction, drilling, storage and mining require stabilization of soil using artificial techniques to impermeate the porous formation along specifically controlled geometries.

Underground storage of natural gas whether in depleted oil or gas reservoirs or in aquifers depends critically upon the existence of an impervious cap to prevent escape of natural gas to shallower or adjacent formations under the influence of buoyancy. The possibility of gas leakage across the caprock or the prospect of using subsurface sands with high porosity and permeability but no suitable cap for underground storage point to the interest in the possibility and desirability of application of special chemicals to permit soil stabilization along desired geometric configurations.

The process by which a special chemical solution is injected into the pores of a porous material to render it impervious to fluid flow across it is called "GROUTING".

Research work on the composition, properties, and applications of grouts have been quite limited to shallow subsurface construction work and some laboratory studies by manufacturers of grouts. The information available in the literature on the application and success of grouting processes have been limited to a large extent on impermeation on an exposed surface. There has been very little, indeed if any information on the application of grouts to problems encountered in underground storage of natural gas.

In order to explore and evaluate physical possibility and economic feasibility of subsurface grouting to remedy leaks from underground storage reservoirs, to provide storage pore volumes of sufficient size, shape, and characteristics, part of the research effort on the "New Concepts on Underground Storage" Project has been directed toward the study of problems associated with grouting.

There are two kinds of grouting materials generally available in the industry today. These may be classified as suspension grouts and true-solution chemical grouts. The suspension grouts such as cement and

bentonite have rather widespread application as surface impermeating materials. These grouts, on the other hand, cannot be used in areas where it is desired to inject the grout beyond the surface pores of the formations. The lithology of typical porous formations where grouts must be used is such that the size of the pores are smaller than those of the particles in suspension in the grouts. In order to impermeate sandstone, limestone, dolomite or shale type of formations, one must go to applications of true solution grouts.

A laboratory study of physical properties of various grouting agents, a systematic compilation of their significant characteristics and evaluation of their injectability into porous plugs and typical field formations, their flow properties, injection, setting, impermeation properties have been the primary objectives of the initial research work reported in the following chapter.

Silicate Grouts

The first chemical grouts were based on sodium silicate, but although sodium silicate is the basis of the silicate grouts, many formula variations have been patented. A survey^{1.1*} in 1957 revealed patents on 27 non-soluble and 17 soluble silicate formulas. Examples and properties of the older silicate gels are listed in Table 1.1. As can be seen from the tabulation, the compositions giving high strength gels had to be injected by the impractical and expensive two shot method. However, Diamond Alkali and Halliburton have recently introduced a one-shot silicate gel which has the strength of the two shot gels. A limitation, however, of the silicates is the viscosity of the silicate solution, about 5-12 centipoises. Although silicate gels are still being investigated, they do not seem to have the low viscosity that this application requires.

Chrome - Lignin Grouts

The least expensive chemical grout is based on calcium ligno-sulfonate, a by product of the paper pulp industry. When catalyzed by sodium dichromate, a gel called chrome-lignin forms. An accelerator such as ferric chloride is sometimes used. The gel time can be controlled by varying the amount of catalyst and accelerator as well as the amount of water. Since water influences the setting properties, the material is highly sensitive to dilution with ground water. The viscosity of the chrome-lignin solution is 3-12 centipoises at room temperature; however, this viscosity increases from the moment of mixing until the gel forms. If dilution does not occur, these gels set with reasonable strength. Although this material has many desirable properties, its use may be limited in the gas storage formations because of its sensitivity to dilution.

1.1* The numbers in upper script parentheses refer to literature citations given at the end of each chapter.

TABLE 1. 1
Properties of Conventional Silicate Gels

Class	Process	Examples	Strength of Gel	Time of Set
non-soluble silicate	one shot [*]	1. Na_2CO_3 or Na_2SO_4 or water glass to mix with salt water in formations. 2. Ester of silicon which hydrolyzes	Low	Sets immediately upon contact with formation water.
non-soluble	two shot ^{**}	Silicic acid-containing substance followed by CO_2 gas	High	Sets when gas reaches solution.
soluble silicate	one shot [*]	1. Sodium silicate + sodium bicarbonate 2. Soluble silicate + weak base	1. Low 2. Low?	1. Sets slowly over a period of time. 2. Gel time controlled with pyridin, ammonium persulfate or ammonium acetate.
soluble silicate	two shot ^{**}	NaSiO_3 followed by $\text{CaCl}_2 + \text{CO}_a(\text{gas})$	High	Sets when gas reaches solution.

Definitions:

* one shot process - Injection of a single solution that gels after a period of time.

** two shot process - Injection of a solution, followed by the injection of another solution which reacts with the first solution to form the gel.

Polymer Grouts

Many polymer materials have also been used as chemical grouts. At least twenty different materials have been used ranging from a formula consisting of furfural + urethane to one consisting of unsaturated fish oil + petroleum distillate + carbon tetrachloride + sulfur monochloride. In general, these materials fall into three classes: (1) completely polymerized molten materials, (2) partially polymerized materials that complete their polymerization in the ground formation, and (3) unpolymerized materials that polymerize in the ground formation. In regard to the present problem, class (1) and class (2) polymers probably are too viscous to flow through the porous media at reasonable rates. However, class (3) polymers seem to offer a satisfactory solution to the problem.

Polymerization Mechanism

Most of the class (3) polymerization reactions proceed by a free radical mechanism. An initiator, a catalyst, and an inhibitor are added to the monomer solution to induce and control the free radical polymerization. The initiator causes the catalyst to decompose into free radicals whereupon an induction period follows before polymerization starts. The inhibitor prolongs this induction period. The length of the induction period is controlled by the relative amounts of initiator, catalyst, and inhibitor present. When polymerization finally starts, the complete polymer is formed in a few seconds.

Herculox

Herculox is a hard setting resin grout available from Halliburton which can develop high compressive strengths. An extremely high strength is developed even though the initial viscosity of the solution is relatively low. This viscosity, however, may be too high for injection into porous media. In addition, the high strength of this gel is probably not needed for impermeation of sandstone but his grout may be excellent for the plugging of cracks and fractures.

Furfural Grouts

The furfural gel was originally developed by Phillips Petroleum for sealing porous walls in oil wells. Laboratory tests indicate that this material may be useful in imperating sandstone or other typical formations in underground storage applications. The gel is prepared with furfural and thiourea with hydrochloric acid as a catalyst. Gel times of 4 to 6 hours have been obtained in the laboratory with about 3 hours required for complete formation of the gel. The viscosity has not yet been measured, but the solution appears very fluid although thickening occurs over a period of time. Since furfural is relatively inexpensive (obtained from corn cobs), this gel could be an inexpensive solution in problems where large injection volumes are required.

AM - 9 Chemical Grouts

Another grouting material on the market at present is American Cyanamid's AM-9 Chemical Grout. The AM-9 is supplied as a fine white powder and is a mixture of N, N'-methylene-bisacrylamide and acrylamide. The catalyst for the system is B-dimethylaminopropionitrile (DMAPN), the initiator is ammonium persulfate (AP), and the inhibitor is potassium ferricyanide (KFe). The AM-9, DMAPN, and KFe are dissolved in a water solution which is stable and can be stored for 24 hours if kept out of sunlight. The AP is dissolved in a separate solution and added to the AM-9 solution immediately before injection.

Table 1.2 below gives a typical composition for AM-9 material.

A typical AM-9 Formulation

1. AM-9 solution	Weight (gm) per 100 gm of grout solution
H ₂ O	79.000
AM-9	10.000
DMAPN	.400
KFe	0.025

2. AP solution	
H ₂ O	10.000
AP	0.500

Gel time = 2 hours at 60° F.

AM-9 Solution Properties

The outstanding characteristics of AM-9 are its low induction period viscosity (constant over the induction period at 1.6 cp) and its accurately controllable gel times. However, it does not appear that the gel times can be made longer than two hours if complete polymerization is to be insured. Another disadvantage is the gel time sensitivity to pH and temperature. Below a pH of 6.5, the gel times become long and indefinite. Furthermore, temperature increase of ten degrees can cut the gel time in half.

The factors affecting the gel time are summarized in Table 1.4.

Because of AM-9's low viscosity, it is very effective in impermeating fine materials. However, considering the relationship between permeability and pumping pressure, it is uneconomical to stabilize very fine materials near the surface because of the difficulty of attaining high pressures. On the other hand, AM-9 was very effective in sealing fine sandstone in a deep shaft where 2000 psi pumping pressure was feasible.

AM-9 Gel Properties

Another advantage of AM-9 is that it is impermeable to water, gases, and hydrocarbons in gelled state. In addition, it will displace water when it is in the liquid state. However, if the ground water is flowing rapidly the solution will be diluted on the periphery and will be displaced somewhat. If turbulent flow conditions are encountered, the dilution effect can be minimized by increasing the AM-9 concentration to 15-20% and by using special formulations to obtain short gel times. On the other hand, if the gel is injected into very dry materials, gravitational and capillary force will act to greatly disperse the solution, rendering it ineffective.

While the AM-9 gel has good water retention properties, under dry conditions a small amount of water will escape causing shrinkage of the gel. Since soil does not shrink, the induced stresses may cause rupture of the gel-soil bonds. This may appear as a visible shrinkage crack. When exposed to humid conditions, the gel will expand and fill the voids but the rupture will not be healed. Strength and good impermeability will then be lost. This probably would not be a problem in deep formations as the water content of the formations remains high.

Core Tests With AM-9

Preliminary tests with sandstone cores have indicated that AM-9 will satisfactorily impermeate the porous media. After AM-9 was injected into the cores and allowed to set, the cores were able to withstand substantial pressure. One core held to 150 psi while another held at 200 psi. It appears that this degree of impermeation will be satisfactory for the underground storage of natural gas. For a complete quantitative evaluation of gas witholding properties of grouts, studies in capillary inhibition, drainage and threshold pressures are now being planned for future work.

Engineering Calculations on Injection of Grouts

Before the grouting material can be injected into a porous formation, pressure requirements and well spacing must be determined to provide

adequate grout penetration. The following example problem illustrates a method of determining the radius of penetration as a function of the well bore pressure.

It is desired to impermeate an aquifer 50 feet in thickness located at a depth of 2000 feet. The sandstone has a permeability of 250 millidarcys and a porosity of 0.15. The grouting material is to be injected from a well 1/4 feet in radius to the porous matrix. Using a grout solution of 1.6 cp viscosity, a gel time of 10 hours specified. Figure 1.1 illustrates the field problem where such an impermeation might be desired.

Formation parting pressure is usually taken as 1 psi/ft. of depth so this pressure is the maximum for grout injection without fracturing the formation. A 10% safety factor may be used making the well bore pressure 0.9 psi/ft. of depth. A dimensionless flow rate is defined as:

$$Q_t = \frac{q}{(6.283) \phi c h r_p^2 (p_g - p_f)} \quad (1.1)$$

where:

$$q = \text{total cumulative influx (ft}^3\text{)} = \phi \pi h (r^2 - r_w^2) \approx \phi \pi h r^2$$

$$\phi = \text{porosity} = 0.15$$

$$c = \text{compressibility of grout solution, } \left(\frac{1}{\text{psi}}\right) \text{ (assumed same as H}_2\text{O)} = 7 \times 10^{-6} \text{ psi}^{-1}.$$

$$h = \text{formation thickness ft.}$$

$$r = \text{radius of penetration (ft).}$$

$$p_w = \text{pressure at the well pore (psi)} = 1800 \text{ psig.}$$

$$p_f = \text{formation pressure (psi)} = \rho g_{g_c} V = 866 \text{ psig.}$$

$$r_w = \text{well bore radius (ft)} = 1/4$$

$$Q_t = \frac{\phi \pi h r^2}{(6.283) \phi c h r_p^2 (p_w - p_f)} = \frac{\pi r^2}{(6.283) c r_p^2 (p_w - p_f)} \quad (1.2)$$

A dimensionless time is defined as:

$$t_o = \frac{(2.634 \times 10^{-4}) k t}{\mu \phi c r_p^2} \quad (1.3)$$

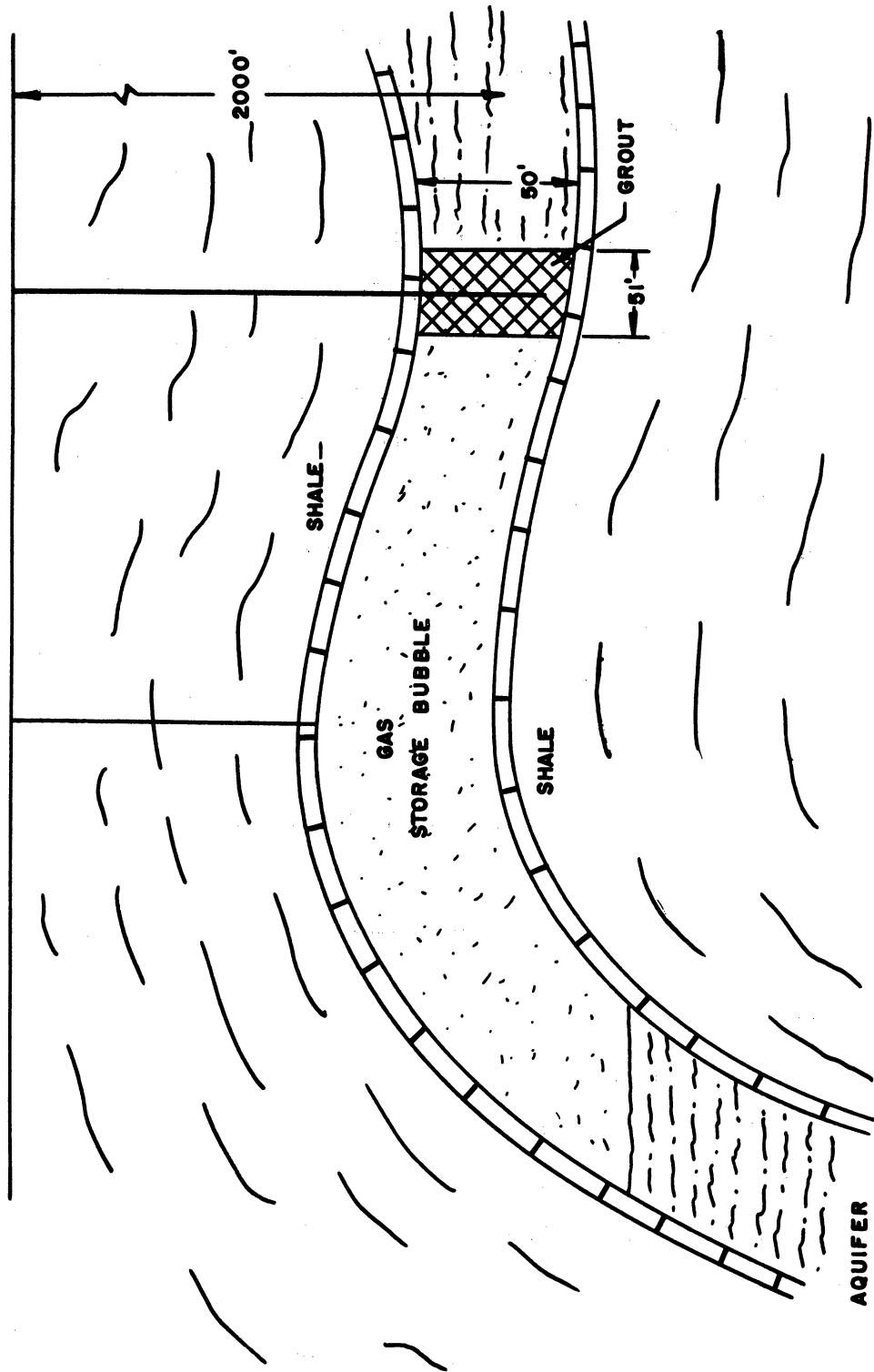


FIG. I.1 TYPICAL APPLICATION OF GROUTING TO AQUIFER STORAGE. (IMPERMEATION OF SPILL POINT)

where:

t = injection time (hours) = 10 hours

k = permeability (md) = 250 md.

μ = grout solution viscosity (cp) = 1.6 cp.

$$t_o = \frac{(2.634 \times 10^{-4})(250)}{(1.6)(0.15)(7 \times 10^{-6})(0.25)^2} = 6.28 \times 10^5 t = 6.28 \times 10^6$$

Q_t and t_o are related and the corresponding values are tabulated on pages 424 - 426 of reference 6. (For radial flow, infinite aquifer, constant terminal pressure). For $t_o = 6.28 \times 10^6$, $Q_t = 8.19 \times 10^5$. Solving equation (2) for r , we obtain:

$$r = \sqrt{\frac{(6.283)(c)(r_p^2)(p_w - p_f) Q_t}{\pi}} \quad (1.4)$$

$$r = \sqrt{\frac{(6.283)(7 \times 10^{-6})(0.25)^2 (1.9)(2000) - 866 Q_t}{3.1416}}$$

$$r = \sqrt{(8.17 \times 10^{-4}) Q_t} = \sqrt{(8.17 \times 10^{-4})(8.09 \times 10^5)}$$

$$r = 25.5 \text{ ft.}$$

Figure 1.2 presents a plot of grout penetration radius as a function of total pumping time for various depths.

Another typical application of grouting to aquifer storage is illustrated in Figure 1.3. This application follows a fracturing treatment in a sandstone formation. Since the propped fracture will have a very large permeability, the pressure throughout the fracture can be assumed equal to the well bore pressure. Therefore, linear flow from the fracture becomes the primary consideration. Once the fracture has been created, well bore pressure must be maintained below the fracturing pressure to prevent possible undesirable fracture extension. Therefore, in the following example, 0.9 psi/foot was used for the well bore pressure.

In this case using equation for linear flow⁷:

$$W_e = 1.13 \phi CA(p_w - p_f) \frac{0.00633kt}{\mu \phi C} \quad (1.5)$$

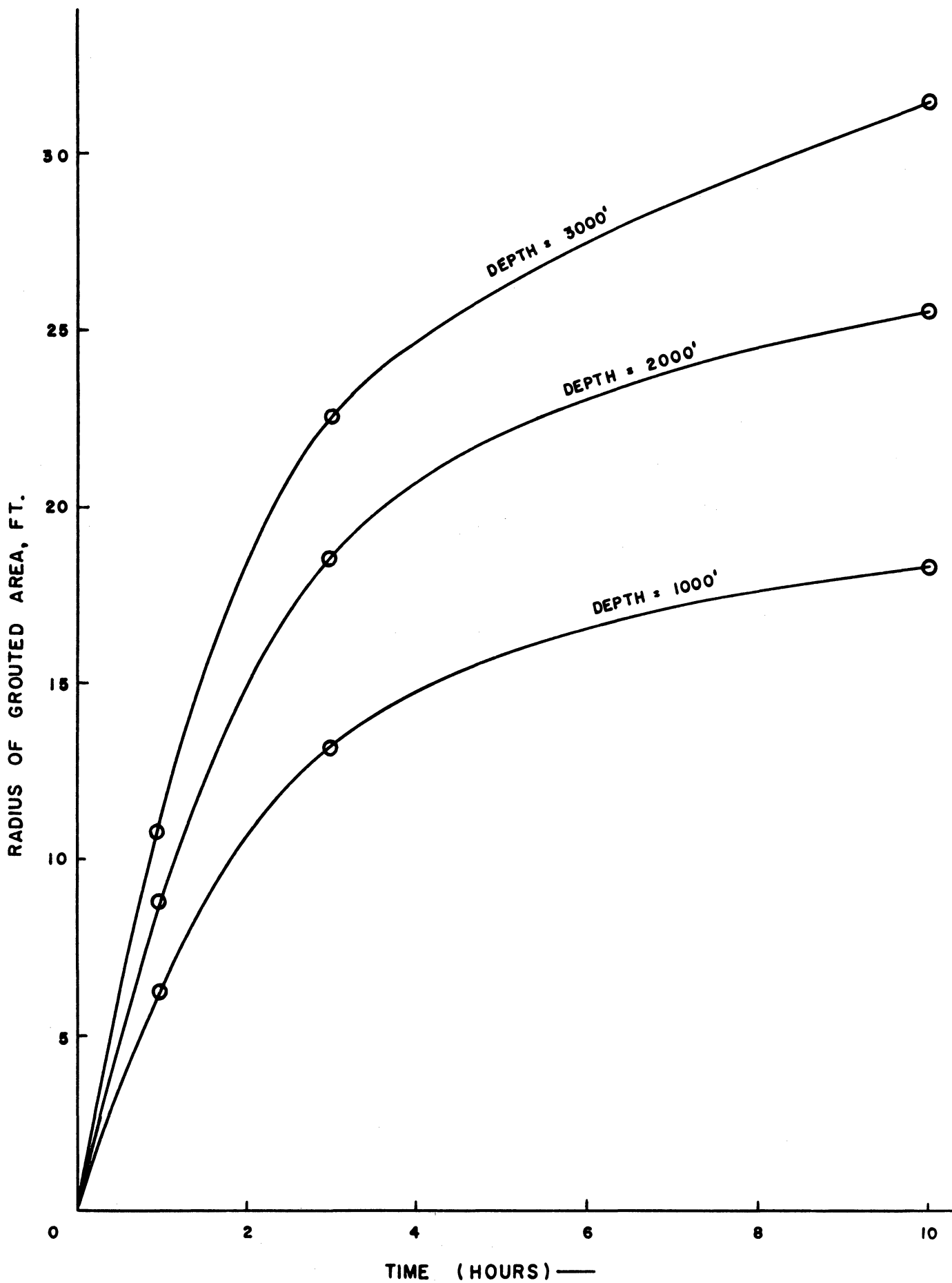


FIG.1.2 RADIAL GROUT PENETRATION AS A FUNCTION OF SETTING TIME AND AQUIFER DEPTH FOR A PRESSURE OF 0.9 PSI/FT.

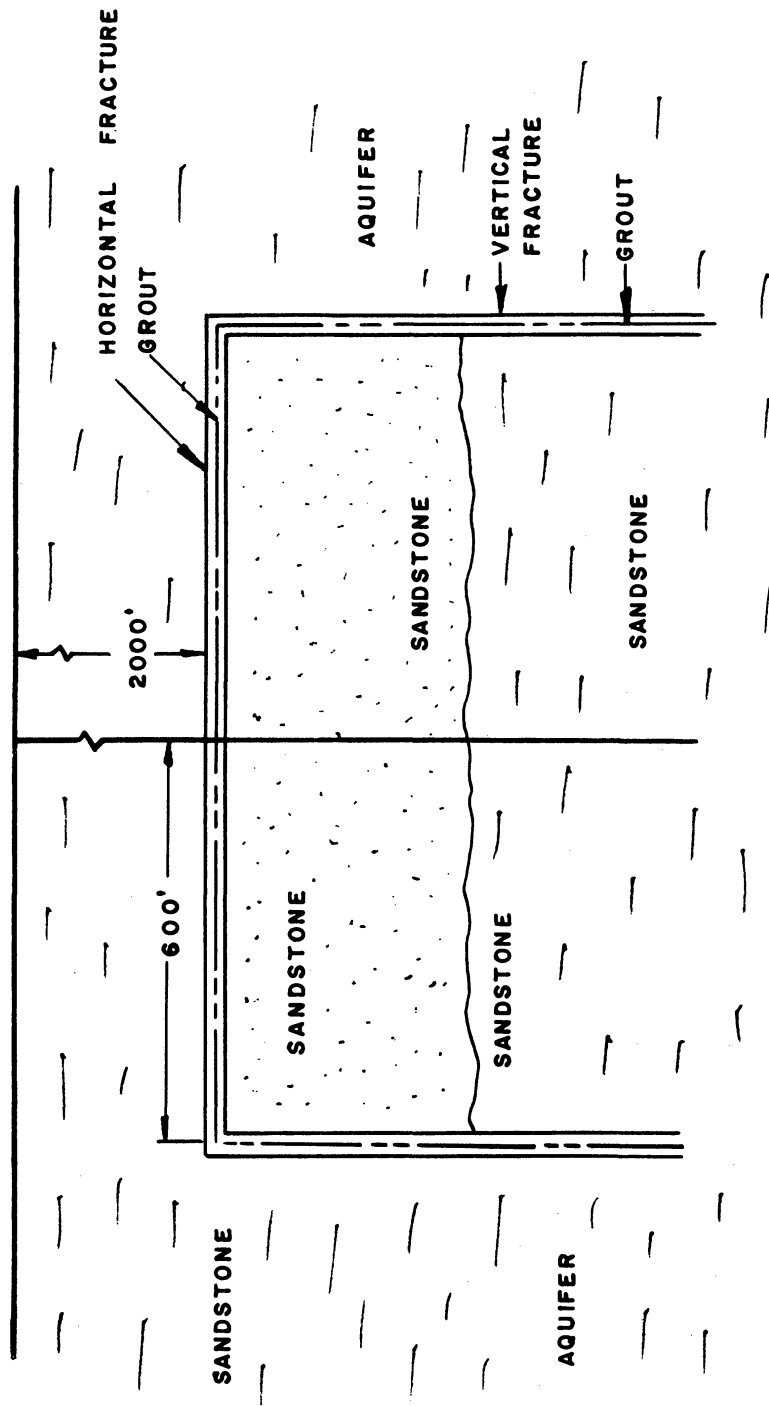


FIG.1.3 APPLICATION OF FRACTURING AND GROUTING TO AQUIFER STORAGE
(NO CAPROCK ORIGINALLY).

where:

$$W_e = \text{total cumulative influx (ft}^3) = \pi r^2 h$$

$$\phi = \text{porosity} = 0.15$$

$$C = \text{compressibility of grout solution, psi}^{-1} = 7 \times 10^{-6} \text{ psi}^{-1}$$

$$A = \text{area} = r^2$$

$$p_w = \text{well bore pressure} = (0.9)(2000\text{ft}) = 1800 \text{ psi.}$$

$$k = \text{permeability} = 250 \text{ md}$$

$$t = \text{injection time (days)} = 10/24$$

$$\mu = \text{viscosity} = 1.6 \text{ cp.}$$

$$r = \text{radius of fracture} = 600 \text{ ft.}$$

$$h = \text{depth of penetration of grout, ft.}$$

$$p_f = \text{formation pressure (psig)} = \frac{\rho_g}{g_c} \Delta h = 866 \text{ psig.}$$

$$\pi r^2 h = 1.13 \phi C \pi r^2 (p_w - p_f) \sqrt{\frac{0.00633kt}{\mu \phi C}}$$

$$h = 1.13 \phi C (p_w - p_f) \sqrt{\frac{0.00633kt}{\mu \phi C}} \quad (1.6)$$

$$h = (1.13)(0.15)(7 \times 10^{-6})(2000 - 866) \sqrt{\frac{0.00633(250)(\frac{10}{24})}{(7 \times 10^{-6})(1.6)(0.15)}}$$

$$h = 0.84 \text{ feet.}$$

Figure 1.4 is a plot of grout penetration as a function of total pumping time for various aquifer depths.

Once the required well bore pressure has been determined the power requirement for the pumps must be calculated. Although these power requirements have been determined, they are not presented here. Such power requirements would only be of interest in the final mechanical design for a field test and therefore are not considered within the scope of current investigation.

A matter of economic importance in aquifer grouting is the optimum well spacing for lowest cost.

$$\text{Cost} = \text{grout cost} + \text{well cost.}$$

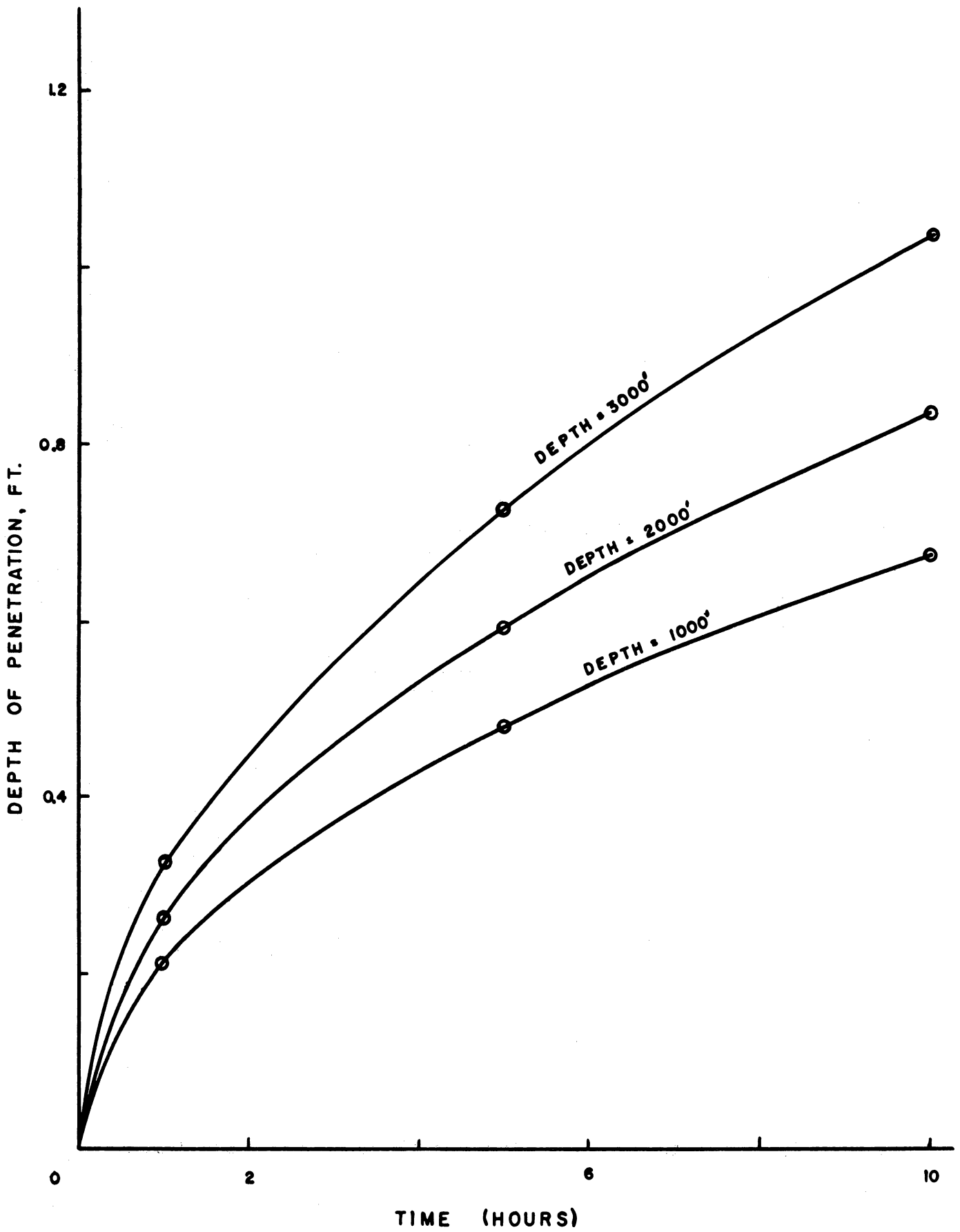


FIG. 1.4 LINEAR GROUT PENETRATION AS A FUNCTION OF SETTING TIME AND AQUIFER DEPTH FOR A PRESSURE OF 0.9 PSI/FT.

$\frac{L}{2r}$ = number of wells needed.

$\phi \pi r^2 h$ = ft³ of grout needed.

$$\text{Cost} = \frac{L}{2r} \left[\phi \pi r^2 h \right] (7.48)A + Bd \frac{L}{2r} \quad (1.7)$$

where:

d = depth of formation, ft.

h = height of aquifer, ft.

ϕ = porosity of aquifer

r = radius of penetration, ft.

L = length of grout wall, ft.

A = cost per gal of gel solution

B = cost per foot for wells (includes pumping)

Finding the minimum of equation 7, we obtain:

$$\frac{d(\text{cost})}{dr} = \frac{L}{2} \phi \pi h (7.48)A - \frac{LBd}{2r^2} = 0$$

$$r = \sqrt{\frac{Bd}{\phi \pi h (7.48)A}} \quad (8)$$

Example:

d = 1000ft.

h = 30 ft.

ϕ = 0.20

A = \$1.00/gal.

B = \$10.00/ft.

$$r = \frac{(10)(1000)}{(0.2)(\pi)(30)(7.48)(1)}$$

$$r = 26.6 \text{ ft.}$$

$$\text{spacing} = 2r = 53.2 \text{ ft.}$$

Figure 1.5 presents a plot of optimum well spacing as a function of aquifer thickness for various depths.

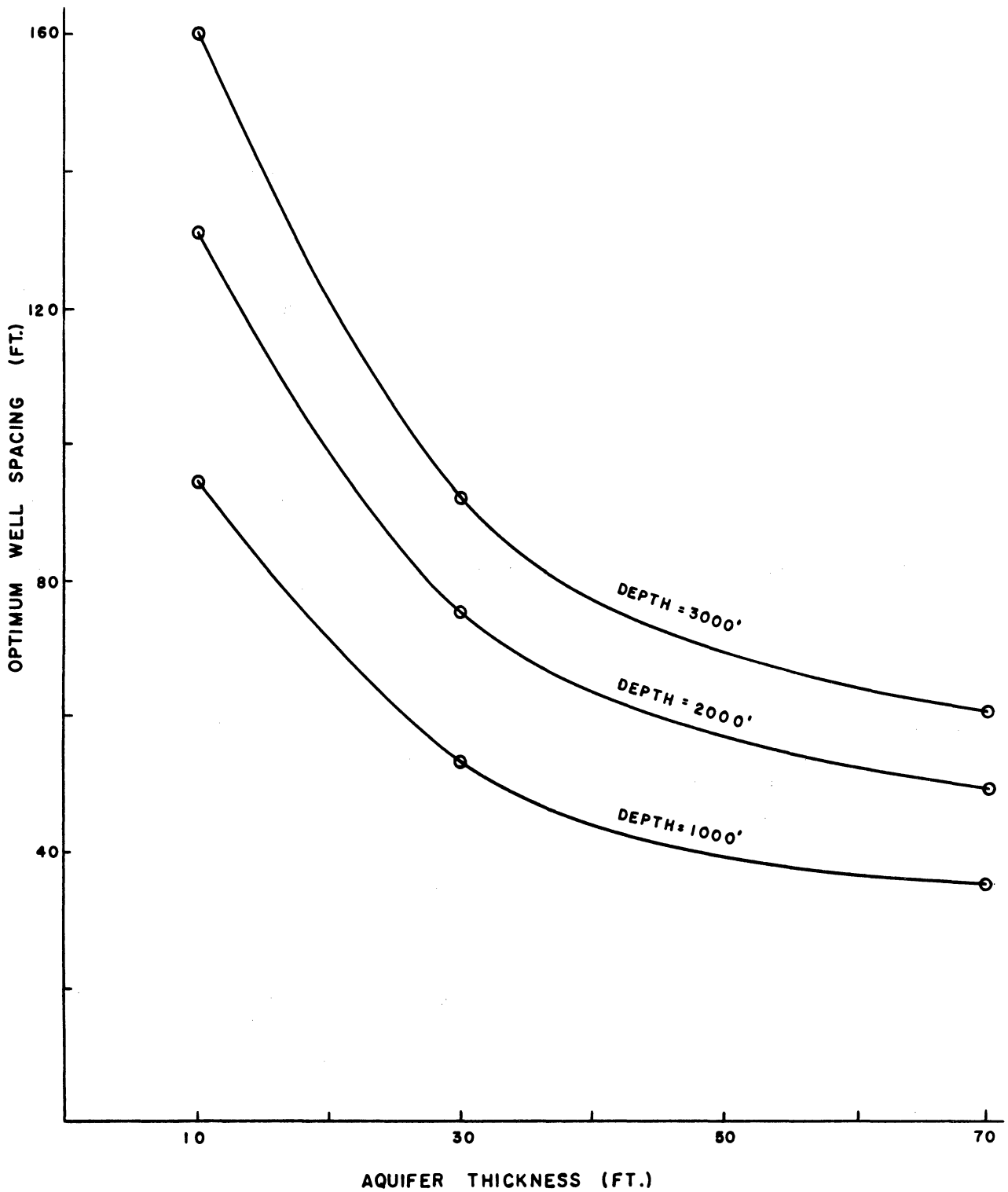


FIG.1.5 OPTIMUM WELL SPACING AS A FUNCTION OF AQUIFER HEIGHT FOR VARIOUS DEPTHS.

Table 1.3 below summarizes physical properties, cost and characteristics for various gels. Table 1.4 is a compilation of factors affecting gel time for the AM-9 grout.

TABLE 1.3 GEL PROPERTIES

	AM-9	CHROME-LIGNIN	HERCULOX	SILICATES
1. Initial Viscosity	1.3-1.6cps (10% soln.)	3-12 cps	10-13 cps	5-12 cps
2. Visc. - Time Relationship	constant	Increases some with time	constant	Fairly constant
3. Compressive Strength	70 psi	53 psi	1400 psi	140 psi (30% soln.)
4. Gel Time (70°F)	0-2 hrs. 0-10 hrs 100°C	0-7 hours	0-5 hrs.	0-7 hrs.
5. Stability*	permanent	permanent	permanent	loses some water
6. Cost (tentative)	1.50/gal	.17-.40/ gal.	1.25/gal	less than .40/gal.
7. Toxicity	Monomer is toxic. Gel does not harm ground water.	Do not use close to ground water supply	Vapors are toxic. Do not use in unventilated places.	Safe for contact with water supplies.
8. Corrosion Data**	corrosive	least corrosive	Most corrosive	least corrosive
9. Sensitivity to water dilution	Can be diluted to a 3% soln.	Very sensitive to dilution	Not easy to dilute, but it can be diluted.	No information.
10. Time from first bit of gel to complete gel.	0 hours	24 hours	24 hours	0 hours.

*Sodium silicate gels made from lignon liquor treated with ammonium hydroxide give unstable gels, while those treated with lime yield stable gels.

** None of the above grouts present serious corrosion problems.

TABLE 1.4
Factors affecting AM-9 Gel Time²

<u>Factor</u>	<u>Effect of Gel Time</u>
1. Reduction of AM-9 concentration	Slight increase
2. DMAPN, AP, and KF_3 concentration	Too much or too little will produce weak gels or none at all. Lower limit is 0.4% for DMAPN, 0.25% for AP, and upper limit for KFe is 0.035%.
3. Temperature	10% rise cuts the time in half.
4. pH	Best range is 7-11. DMAPN maintains pH at 8-9 except at high acid concentration. Below pH = 6.5, gel times are long and indefinite.
5. Air	If solution is saturated with air, the gel time is longer.
6. Metals	Iron, copper, and copper alloys decrease gel time. Most use aluminum, stainless steel, plastic or rubber equipment.
7. Mix Water	Impurity in mix water may affect time. Test should be carried out with water that will be used in the field.
8. Sunlight	Sunlight will gel AM-9 solutions left uncovered.
9. Inhibitors	Although most polymerization inhibitors can be used, these will result in weak gels. KFe does not hurt the strength.
10. Hydrogen sulfide	Shortens gel time.
11. Salts	Soluble salts (NaCl, $CaCl_2$, etc), present in the formation decrease gel time although increasing strength.
12. Freezing	Prevent by using any commercial antifreeze.
13. Insoluble material	Fine insoluble particles such as clay or bentonite slow down the gelation to some extent

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2. UNDERGROUND STORAGE IN NON-POROUS SPACE

The storage of first manufactured and later natural gas has evolved in the past along a pattern closely related to development and growth of production and consumption of natural gas. Through the years, this pattern followed the sequence from storage in surface tanks, to underground storage in depleted gas or oil reservoirs and finally to storage in aquifers. For reasons of capacity, economy and safety, the surface storage in tanks is now virtually completely out of the picture. On the other hand, wherever possible a depleted natural gas reservoir usually offers perhaps the most reliable means for underground storage of natural gas. Such a subsurface storage volume not only has the distinct advantage of having been proved by nature throughout the geologic ages to retain the gas in-place but usually is of large capacity. Such subsurface formations also have the added feature of being well known, charted and adequately understood from the viewpoints of reservoir engineering by the time they are depleted and ready to revert to storage service. As experience and knowledge on properties of such a reservoir is added through reservoir engineering, as resistance to fracturing, threshold pressure, permeability, compressibility, etc. becomes better known and the extent and nature of water drive along with subsurface geometry is understood and verified, the practice of "overpressuring" such reservoirs within safe limits usually adds appreciably more storage capacity to the depleted gas producing field.

The depleted oil reservoir affords approximately the same advantage as the depleted gas reservoir. Existence of reliable cap, suitable structural trap, reservoir properties determined from data collected throughout the producing life of the reservoir, estimation of original and actually recovered reserves, thus of the pore space are among many typical characteristics quite helpful in initiation and maintenance of gas storage in such reservoirs. As opposed to these and some other advantages, however, the storage in depleted oil reservoirs poses some rather difficult engineering problems of unique nature. These problems usually stem from the presence of unrecovered residual crude oil in the pore space. The miscibility of

residual oil with injected gas, low relative permeability due to two phase flow, handling of the production of oil along with gas, difficulties in reconciling the inventory gas with production pressure behavior of total reserves are typical of problems which must be dealt with in storing the natural gas in depleted oil reservoirs.

During the last decade the phenomenal growth of domestic consumption of natural gas precipitated the acute need for storage of natural gas in areas where there are no depleted oil or gas reservoirs present. The advent of aquifer storage where the pore volume necessary to store the gas is created by pressurizing aquifers above their discovery pressure through gas injection provided during the last decade very substantial storage reservoirs in such areas of need. 2. 40

The storage of natural gas in aquifers depends upon existence of suitable structure, closure, and, cap rock. These factors though perhaps more readily or more frequently available along with suitable porosity and permeability close to areas of high domestic gas consumption than producing or depleted gas or oil reservoirs are not always altogether present. Quite often an aquifer sand of high porosity and permeability will exist at some reasonable depth but will not have adequate structural closure. Quite often, on the other hand, such a structure will have adequate closure, but unfortunately no suitable cap rock. Other times, impervious cap rock, good porosity, high permeability will be present but only a semi-open structure will delimit the subsurface geology.

There has been substantial amount of field data gathered recently indicating that caprocks overlying many storage reservoirs are subject to leakage of gas to shallower formations when the gas pressure exceeds a certain critical value. Such leaks are sometimes area distributed and related to drainage capillary pressure characteristics of the shale. At other times, it appears that the leak may be along a fracture line and primarily due to having the gas overpressure in excess of the threshold pressure of the shale.

The possibility and desirability of storage in aquifer sands where one or more of the prime requirements is non existent, or storage in

depleted petroleum reservoirs above the original content of hydrocarbons, beyond levels indicated by location of spill points all point to needs of new concepts in underground storage where soil impermeation should play a significant role.

There are many areas in the United States^{2. 39} where sedimentary rocks are known to be practically nonexistent. Some of these areas are located near industrial complexes in highly dense populated areas where underground storage must depend on relatively or entirely new concepts and ideas. Subsurface storage of natural gas, in non-porous, void continuum such as salt caverns, mine shafts, have been suggested and empirically tried to limited extents in the past. Near surface porous storage in such areas as gravel pits, sand dunes, surface sands and the possibility of gas storage under lakes or oceans are among many new concepts which will be reviewed and discussed in the following.

Salt Cavern Storage

For many years, natural gas producers have needed a way to store their product near the consumer to provide a buffer during peak consumption periods. Storage in underground void spaces such as mines and salt cavities has been suggested as a means to provide such a reservoir for natural gas. Some technology is available in this field as liquified petroleum gases (propane-butane) have been stored in mines and cavities for over ten years. As early as 1952, the Natural Gasoline Association of America prepared standards for the operation and testing of underground storage wells.^{2. 28}

Location of Dissolved Salt Caverns

Cavities may be formed in either salt beds or salt domes. Salt beds occur in the western part of Texas, Oklahoma, Kansas, and eastern New Mexico and in the Great Lakes region of Michigan, Ohio, Pennsylvania, and New York. Salt beds also occur in the Uintah Basin in Utah and Colorado outcropping at the surface in some areas and down to depths of 7000 ft. in others. In the Texas-Oklahoma-Kansas-New Mexico area, the salt beds range in depth from 1000 to 2000 feet and in thickness from 50 to 100 feet. In the Great Lakes region, the beds range in depth from 1500 to 7000 feet

and in thickness from 1-400 feet. Almost all of the beds contain thin layers of shale, anhydrite, etc. This causes some problems in the formation of cavities. Salt domes are for the most part located along the Gulf Coast of Texas, Louisiana, Mississippi, and Alabama. These domes vary in depth from near surface to depths that lie beyond the reach of present day drilling equipment. The dome usually consists of nearly pure rock salt. Salt domes are usually the best formations in which to provide underground storage.^{2. 33}

Safety Considerations

The acid industry, as well as others, have brine wells exceeding 1,000,000 bbl. in cavern volume. A cave-in in a cavity containing brine usually does not involve serious damage to surface equipment. Collapse, fracture, or leakage of an LPG or natural gas storage cavity, however, may result in serious leaks, explosions or fires.^{2. 21} It is, therefore, important to design the cavern within the limits of various safety considerations.

Strength Data For Salt

A specific safe limit to cavern size is, at the present time, virtually impossible to calculate. In homogeneity of rock compacted through complex geological processes confronts the designer with such variables as fracturing, slams, and faults. Some data for anhydrites and salt formations are available from core samples. A typical sample taken from salt formation at 2000 feet in West Texas, for instance is reported to yield the following data on unconfined compressive strength.^{2. 21}

Salt - 2600-4000 psi

Anhydrite - 4500-23,000 psi

Ultimate compressive strength when confined, was found to be:^{2. 21}

Salt - 17,000 psi @ 2000 atm and 150°C.

Anhydrite - 82,000 psi @ 2000 atm and 150°C.

Triaxial tests on anhydrite under formation pressure conditions indicate ultimate shear strength in the range 12,000 to 14,200 psi while measured compressive strengths reached 28,000 psi.^{2. 21} The following fundamental properties of the aggregate salt from the Grand Saline salt mine were determined:^{2. 36}

The maximum compressive stress	2300 psi
with the standard deviation	200 psi
The 0.5% yielding stress	2000 psi
Young's Modulus	0.14×10^6 psi
with the standard deviation	$.03 \times 10^6$ psi
Poisson's ratio	
with the compressive stress up to 300 psi	0.25-0.5
with the compressive stress over 300 psi	0.5

Deliverability of Natural Gas from Salt Cavern Storage

When natural gas is stored in a salt cavern, the stress condition induced in formations surrounding the dissolved cavity depends upon mechanical characteristics of these formations, weight of the overburden, shape of the cavity and the pressure of the gas inside the cavity.

In the early phases of development of salt cavern storage because of uncertainty of stress calculations, it was felt that one would probably have to maintain full hydrostatic pressure at the salt cavern in order to prevent collapse due to the weight of the overburden. To make this possible, saturated brine would have to be pumped in and out during each production injection phase of the storage. In other words, a dissolved salt cavern 2000 feet deep would be maintained say at 860 psig all the time. This cavern pressure can be maintained if every cu. ft. of gas pumped out is replaced by a cubic ft. of brine pumped in and vice versa. Accordingly, it becomes interesting from a storage engineering view point to determine the brine pumping requirement necessary to maintain cavern pressure at varying rates of gas deliverability. If the water pumped into the cavern only partially replaces the gas being produced, then the cavern pressure drops as a function of time accordingly.

In the following example, a relationship will be derived for predicting the decline of cavern pressure versus time for various fractions of brine replacing the gas withdrawn.

In order to fix the ideas, let us assume that: (1) Cavern has a volume of 10^9 ft³ and is located 2000 feet below the surface; (2) Withdrawal rate is 50×10^6 SCF/day; (3) Cavity temperature is constant at 100°F.

Q_s = withdrawal rate = 50×10^6 SCF/day.

V_c = cavity volume = 10^9 ft.³

T = cavity temperature = 100°F .

T_s, Z_s, P_s = standard temperature, compressibility factor, and pressure, respectively.

T_o, Z_o, P_o = original temperature, compressibility factor, and pressure, respectively

$$P_o = \frac{g}{g_c} \rho h = 865 \text{ psig}$$

t = time in days after withdrawal has started.

T_i, Z_i, P_i = temperature, compressibility factor, and pressure, respectively, at time t .

V_G, n_G = volume and moles of gas, respectively, at time t .

n_o = initial number of moles of gas.

f^* = fraction of gas withdrawn that is replaced by water (corrected to actual reservoir conditions).

Q_L = water injection rate, ft³/day.

Q_s = gas production rate STDcu. ft. per day.

$$Q_L = f^* Q_s \left(\frac{P_s}{P_o} \right) \left(\frac{T_i}{T_s} \right) \left(\frac{Z_i}{Z_s} \right) \quad 2.1$$

Material balance:

$$V_G = V_C - Q_L t \quad 2.2$$

$$\text{but } V_G = \frac{Z_i n_G R T_i}{P_i} \quad 2.3$$

$$\text{where } n_G = \frac{P_o V_C}{Z_o R T_i} - \frac{Q_s P_s}{Z_s R T_s} t \quad 2.4$$

$$V_C - Q_L t = \frac{Z_i R T_i}{P_i} \left[\frac{P_o V_C}{Z_o R T_i} - \frac{Q_s P_s}{Z_s R T_s} t \right] \quad 2.5$$

It should be noted that $Z_s = 1$ and $\frac{P_s}{Z_s R T_s} = \frac{1}{378} \frac{\text{moles}}{\text{ft}^3}$

Substituting (1) in (5) and solving for P_i yields:

$$P_i = \frac{\frac{Z_i}{Z_o} \left[P_o - \frac{Q_s P_s T_i Z_o}{V_c T_s Z_s} t \right]}{1 - f^* \frac{Q_s P_s T_i Z_i}{V_c P_o T_i Z_s} t} \quad (2.6)$$

This equation must be solved by trial and error since Z_i is a function of P_i and T_i . Z values are functions of pseudo-reduced temperature and pressure are available in the literature.^{2, 39} Equation (2.6) is presented graphically in Figure 1 for various values of f^* .

Stress Considerations

When the creation or extension of a salt cavern is considered, it is important to know the cavern volume that can be washed out without danger of cavern collapse. Induced stresses must also be considered when the cavern pressure is reduced below formation pressure. An approximate but reliable correlation giving the induced stresses as a function of geometry, rock properties and reservoir variables is now being developed. More specifically, this correlation will give induced stresses from cavern dimensions, shape, pressure, depth, thickness of overlying consolidated formations, and physical properties of the surrounding formations. With such a correlation, one could create maximum cavern volume without danger of collapse. In addition, one could calculate the minimum storage pressure which would be permissible for a given dissolved salt cavern. Once the operating maximum and allowable minimum cavern pressures are determined then the deliverability of gas from the cavern and the necessary pumping requirement for maintenance of cavern pressure may be readily calculated. The results of the stress correlations developed for salt caverns along with comparisons and applications to direct field data will be included in the next progress report.

Creation of Salt Cavern Reservoirs

Washing - The process of washing out a cavern in rock salt is inexpensive (from 19 cents to \$1.80 per bbl) and simple: a shaft is drilled into a subterranean salt stratum; and, by pumping water in suitable rates under appropriate pressure, the salt is dissolved and brought to the surface,

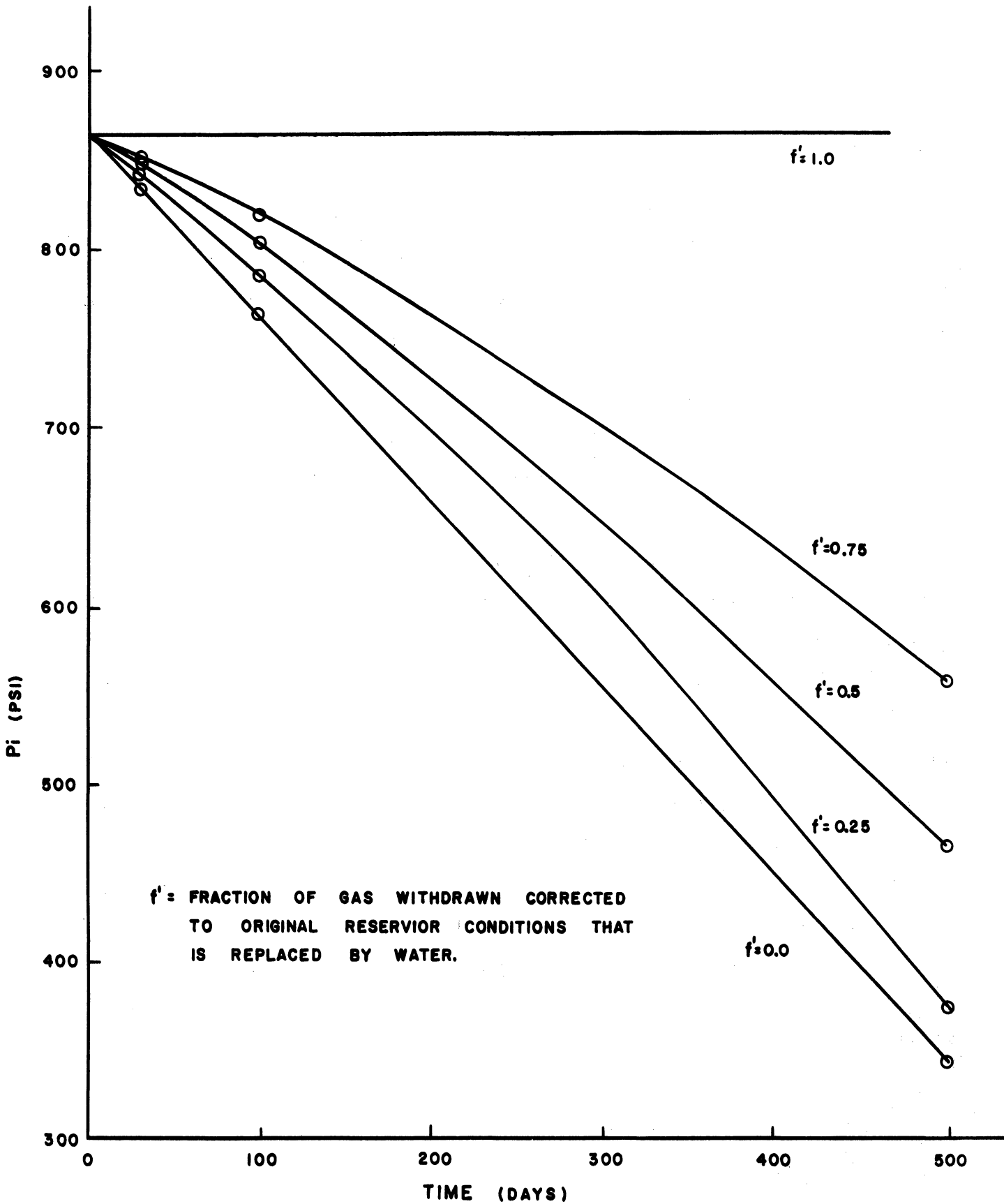


FIG. 2.1 SALT CAVERN STORAGE VARIATION OF RESERVOIR PRESSURE WITH TIME FOR VARIOUS DEGREES OF WATER REPLACEMENT.
 ($V_c = 10^9$ FT.³, $Q_g = 50 \times 10^6$ SCF/DAY)

leaving an opening of the desired size within the stratum.^{2.7} In theory, every 6.03 bbl of fresh water will dissolve one bbl of salt. In practice, about 11% capacity is experienced with each unit volume of wash water. It has been observed that in about seven wash volume turnovers, the cavern size doubles, in 11 it triples.^{2.5}

Salt cavities should be formed in an area free from shale ledges if possible. If present, these ledges may break off and kink or snap any brine or product tubes that might be located in the cavity. In some operations, the amount of insolubles may be excessive and tubing may have to be raised from the bottom of the cavity to prevent plugging.

There are three methods of developing the salt cavity: (Figure 2.2) (a) bottom injection; (b) reverse circulation and (c) progression technique.^{2.21}

Determination of the Size of Dissolved Salt Caverns

After a cavern has been washed, accurate dimensions of the caverns are usually desired. If the cavern shape is assumed to be without stringers of insoluble material and that it approximates a cylinder, then volume height data will fix the diameter.^{2.15} This volume height relationship can be obtained by measuring the difference in shut in annulus pressures of the liquified hydrocarbons at the surface after successive additions of known volumes to the cavern. The rise in pressure together with the calculated base pressure required on the annulus to balance the brine column from the bottom of the casing permits the calculation of an equivalent diameter at various test points. Referring^{2.16} to Figure 2.3, it will be recognized that

$$h = \frac{P}{0.434(d_B - d_P)} \quad (2.7)$$

or

$$\Delta h = \frac{\Delta P}{0.434(d_B - d_P)} \quad (2.8)$$

Where h = depth to the LP gas brine contact, feet.

P = casing pressure, psig.

d_B = specific gravity of brine.

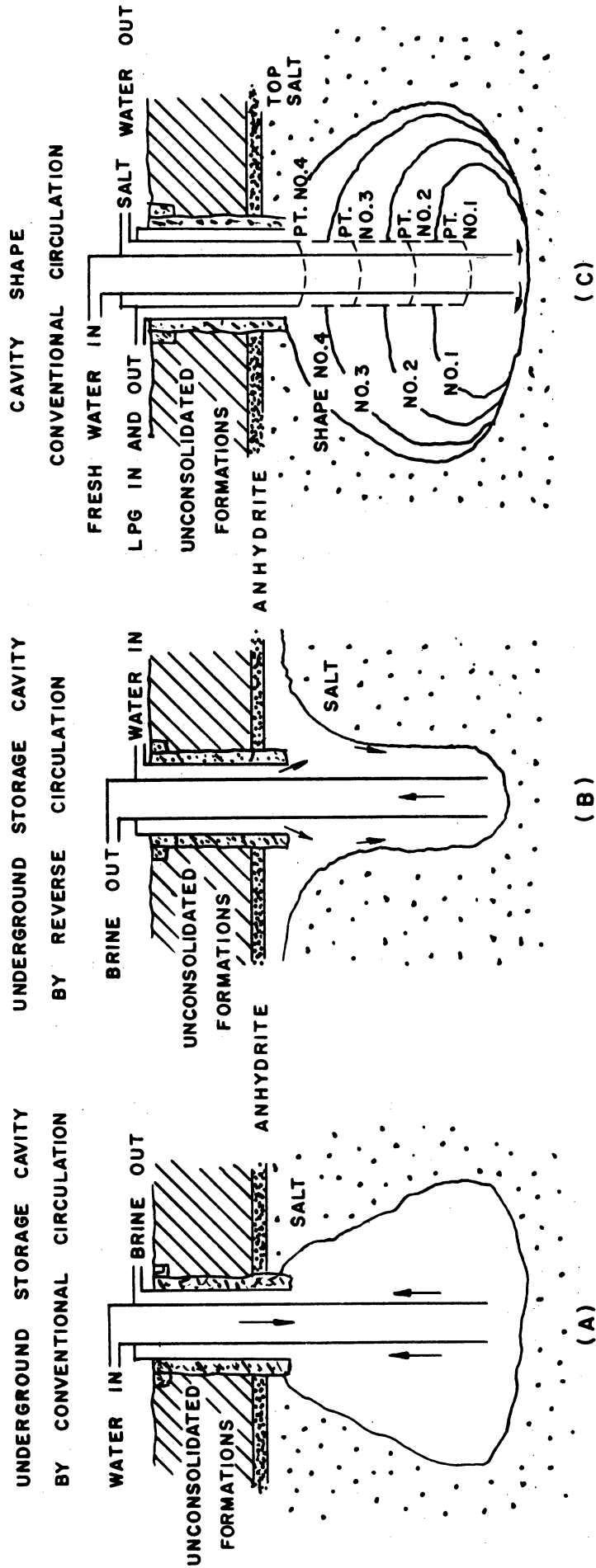


FIG. 2.2 THREE METHODS OF DEVELOPING CAVITIES: (A) CONVENTIONAL BOTTOM INJECTION METHOD
 (B) REVERSE CIRCULATION TECHNIQUE (C) PROGRESSION TECHNIQUE WHERE BY WASH PIPE
 IS MOVED TO CONTROL CAVITY SHAPE.

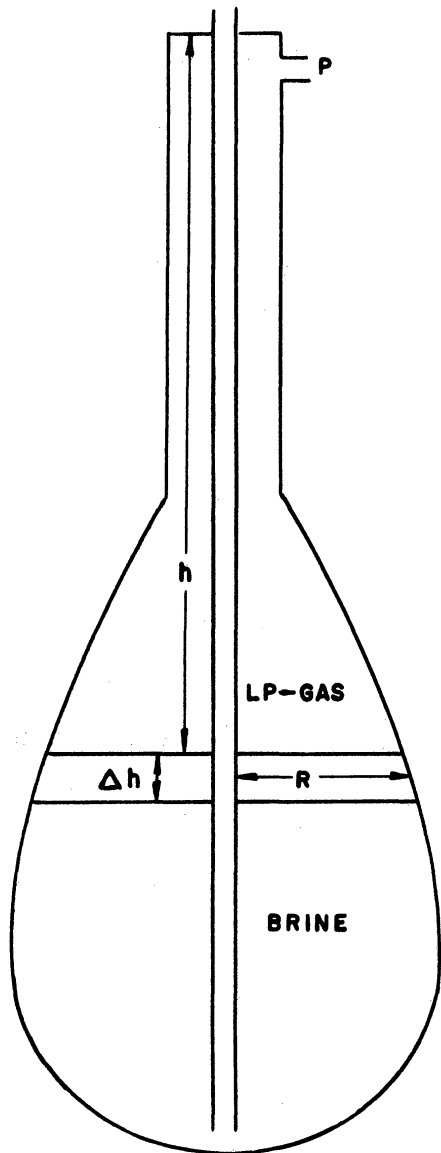


FIG.2.3 A SIMPLIFIED VIEW OF A SALT STORAGE WELL.

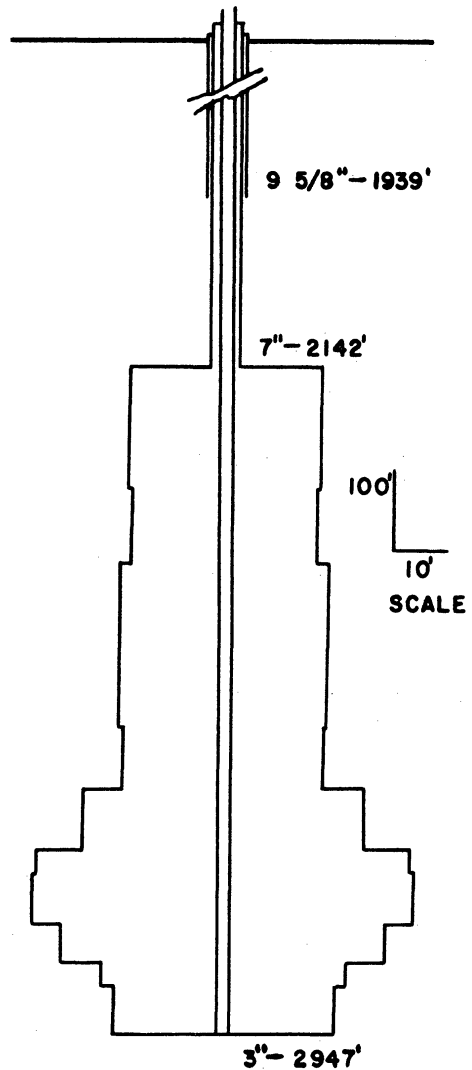


FIG.2.4 AVERAGE CAVERN DIAMETERS AS DETERMINED FOR EQUILIBRIUM PRESSURE CALCULATIONS.

d_p = specific gravity of LP gas.

The average cavern radius for the part of the cavern can be calculated for any interval by,

$$R = 3.40 \sqrt{\frac{\Delta G}{\Delta h}} \quad (2.9)$$

Where Δh = vertical height filled during interval, feet.

ΔG = gallons LP gas injected for the interval.

R = average cavern radius for the interval, feet.

Figure 2.4 shows a typical cross section that has been calculated for a Petal Dome storage cavern. ^{2.16}

Fracturing - When creating caverns in salt layers, fracturing may be employed to facilitate the cavern construction. Two or more wells may be sunk and connected by fracturing. The bed may then be washed out to provide a large storage area. Fracturing probably cannot be used in salt domes because the general homogeneity of physical properties of salt may not lend itself to controlled horizontal fracturing.

Recovery of LP Gas From Caverns

While this report is primarily concerned with storage of natural gas in caverns there are many aspects of L. P. G. storage know which may also be applicable to natural gas storage. It is for this reason that literature in formation on recovery of L. P. gas is included in the following. When the reservoir is filled, some hydrocarbons will be lost in permanent storage. This loss is relatively small ^{2.15} and most of the gas can be recovered. Gas recovery can be accomplished by: (1) Brine displacement, (2) Pumping, (3) Vaporization, (4) Gas displacement. Brine displacement has one advantage and a serious disadvantage. If the brine used is saturated, the cavern size will not change. Surface storage or disposal of the brine usually constitutes a problem. In some instances simultaneous operation of brine wells near underground storage cavities provides the gas reservoir with ample brine for displacement. A second alternative is to have a large asphalt lined surface basin for temporary brine storage. Prefabricated asphalt lining can be installed for about 30 to 35 cents per square foot. ^{2.5} The static

pressure difference between the brine and hydrocarbons is approximately 600#. It is necessary, therefore, to have a pump with about a 1000# discharge pressure to handle the pipeline flow rates.^{2. 15}

In LPG storage, product removal by pumping has several disadvantages although brine is eliminated in the storage process. The amount of product that can be handled by a centrifugal pump decreases rapidly with depth. In caverns up to 1000 feet deep, discharge rates are as high as 1500 GPM. If the depth is increased to 1500 feet, the rate drops off to about 20 GPM; and beyond 3000 feet the centrifugal pump loses all practicality.^{2. 5} In addition, the products being pumped are poor lubricants, creating high maintenance costs. Furthermore, pumping will allow the cavern pressure to drop to a point where cavern collapse may occur.

Product removal can also be accomplished by vaporization lift. In this method, hydrocarbon vapors are withdrawn from a relatively small diameter tube that extends to the bottom of the storage chamber. These vapors are recompressed and injected into the vapor space above the liquid in the cavern. Bubbles caused by the vaporization of liquid hydrocarbons under reduced pressure within the tube create, in effect, a gas lift which will carry products out of the hole. Although this method is relatively expensive and is limited in depth of operation to 1400 feet, it eliminates the need for downhole pumping equipment and at least partially preserves the cavern pressure.

Product removal by gas displacement forces the liquid out of the cavity by virtue of high injection pressures. It does not involve extra pumping equipment and is adaptable to any depth and rate. However, it requires a gas source capable of both giving and taking large quantities of gas at irregular rates.

Mined Storage

Locations

At the present time, there are at least 29 mined storage caverns completed or under construction in this country with a total capacity of nearly 5 million barrels.^{2, 3} Abandoned coal mines, salt mines, and ore mines are included in this category as well as mines especially constructed for

LPG storage. Geographic formations suitable for construction of underground caverns are indicated in Figure 2.5.

Coal Mine Storage

A well constructed coal mine may constitute a ready-made storage reservoir. First, however, test drillings should be made to determine the permeability of the formations around the mine. Tests on a Denver mine^{2.13} showed that the strata above the coal seam were of sufficient strength and of low enough permeability to serve as a "cap rock" for the reservoir. The vertical distance between the surface outcrop and the mines operating level fixes the pressure at which the reservoir is to be operated. At the Denver mine, an upper limit of 300 psig for storage was selected while the operating pressure used for storage was 200 psig.

Hard Rock Mined Storage

Hard rock mining is often the only solution to a storage problem due to the conditions of the subsurface formation. This type of storage is exemplified by Sinclair Oil and Gas Co.'s 5,000,000 gallon hard rock underground storage of LPG near Seminole, Oklahoma.^{2.12} Conventional mining methods and equipment were used to construct the mine. The mine was tested for leakage with dehydrated air at 150 psig and 90 to 100 psig was used for storage.

A hard rock mine was also constructed at the Bayway refinery of Esso at New Jersey^{2.7} at a depth of 330 ft. Total capacity is about 675,000 bbl. Large pillars of shale were left in place during the excavation to provide support. The support pillars are actually larger than the excavated area, making the reservoir a series of interconnected tunnels.

The techniques presented for LPG storage possibly can be used in the storage of natural gas. The Gulf Coast, Mid West, and Great Lakes regions with salt formations offer the salt dome and salt bed storage, while the coal and ore mining areas might be considered for storage in abandoned mines. In the eastern states, many of the large centers of population are over solid rock formations. Hard rock mining may provide some possibilities for gas storage of the type first discussed. The table 2.1 compares costs of various types of LPG storage methods.

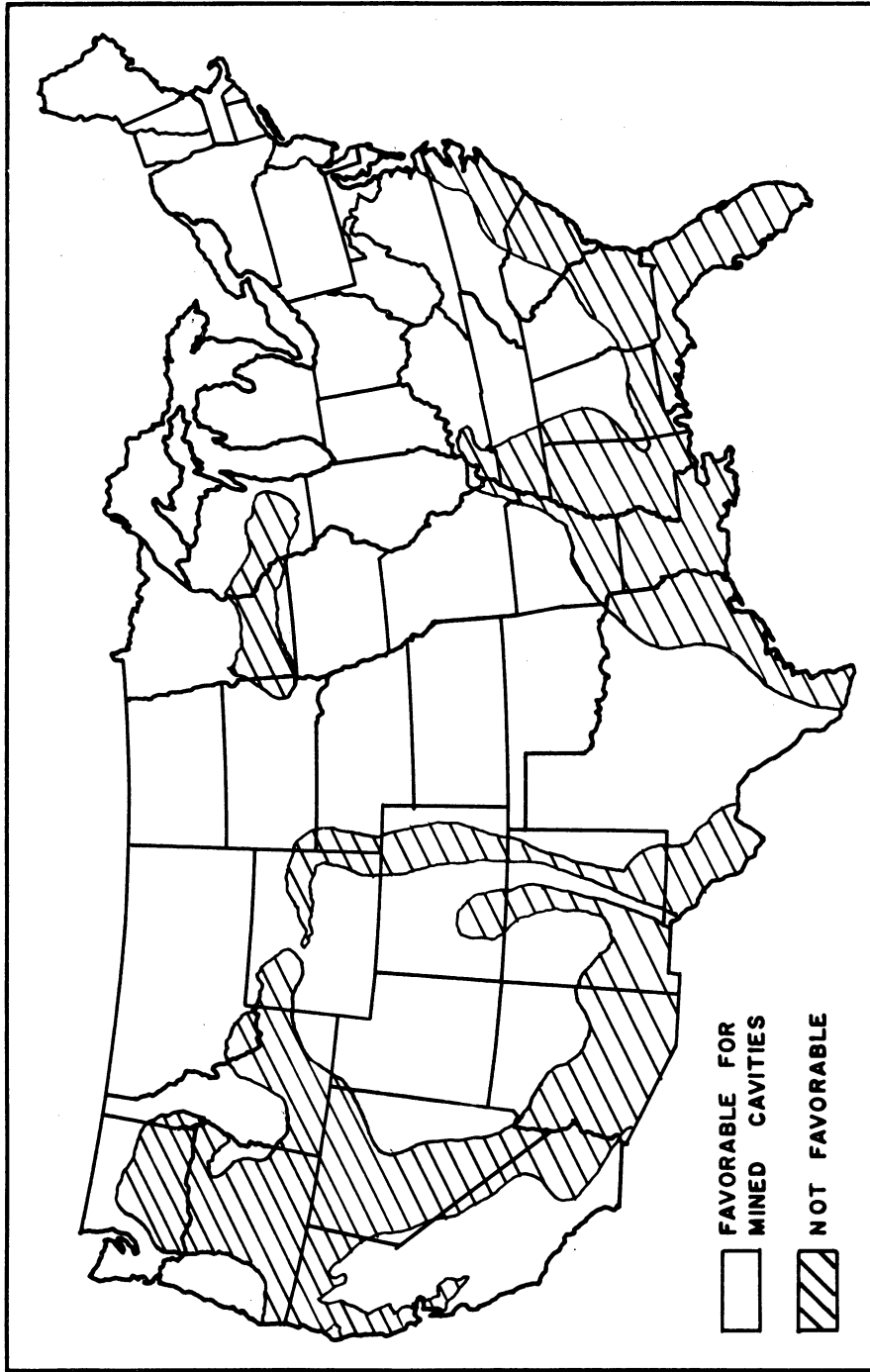


FIG. 2.5 GEOLOGICAL FORMATIONS SUITABLE FOR CONSTRUCTION OF THESE UNDERGROUND STORAGE CAVERNS ARE FOUND IN MANY PARTS OF THE U.S. AND BROAD AREAS HAVE BEEN TENTATIVELY CLASSIFIED AS FAVORABLE OR UNFAVORABLE.

TABLE 2.1. COSTS OF LPG STORAGE 2.15

Type of Storage	Cost per bbl. , \$
High pressure above ground storage (propane)	20.00 - 30.00
Mined Storage (propane-butane)	7.00 - 15.00
Low-Pressure-above ground spheroid refrigerated (butane)	12.00 - 20.00
Salt cavern (propane-butane)	0.75 - 3.50

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3. DETECTION AND REMEDY OF LEAKS FROM STORAGE RESERVOIRS

When natural gas is stored in underground formations, whether such storage is in depleted gas or oil reservoirs, or in aquifers, the presence of a suitable cap rock is of paramount importance for the required retention of gas. Obviously, a depleted reservoir must have a cap proved throughout the geologic ages as impervious to the migration of hydrocarbons across it. However, if it is desired to "overpressure" the reservoir, an excessive overpressure may cause the cap rock to leak. In aquifer storage, the gas bubble is practically always at a pressure above the original aquifer pressure. Because aquifer storage projects are continuously operated under "overpressure" conditions, the leak from aquifers across the cap is likely to occur if and when the reservoir pressure reaches some critical value.

Overpressuring of Storage Reservoirs

A large number of oil and gas reservoirs are in contact with blanket-water sands or aquifers which outcrop somewhere to the surface of the earth.^{3.12} Such reservoirs are usually discovered at a pressure resulting from the hydraulic gradient related to the elevation of the outcrop location. Even when there is no direct communication with surface waters, many such reservoirs have pressures that conform to this gradient. This fact is considered by many as the supporting evidence to theories of underwater sedimentation and compaction usually advanced to explain the origin and occurrence of petroleum deposits. Any moderate variations in depth-pressure distributions are from those predicted by the normal hydrostatic effect are sometimes explained by a varying salt composition of subsurface waters along with existing geothermal gradients in the crust of the earth.

Figure 3.1 shows discovery pressures vs. depth for various petroleum reservoirs. In examining Figure 3.1, one must observe the significance of the limiting gradients; the upper limit of 1.0 psi/ft is considered to be due to the weight of the overburden, and the lower limit of 0.433 psi/ft is the hydraulic gradient for pure water. Beyond these two limits, abnormal discovery pressures are occasionally found on both the high

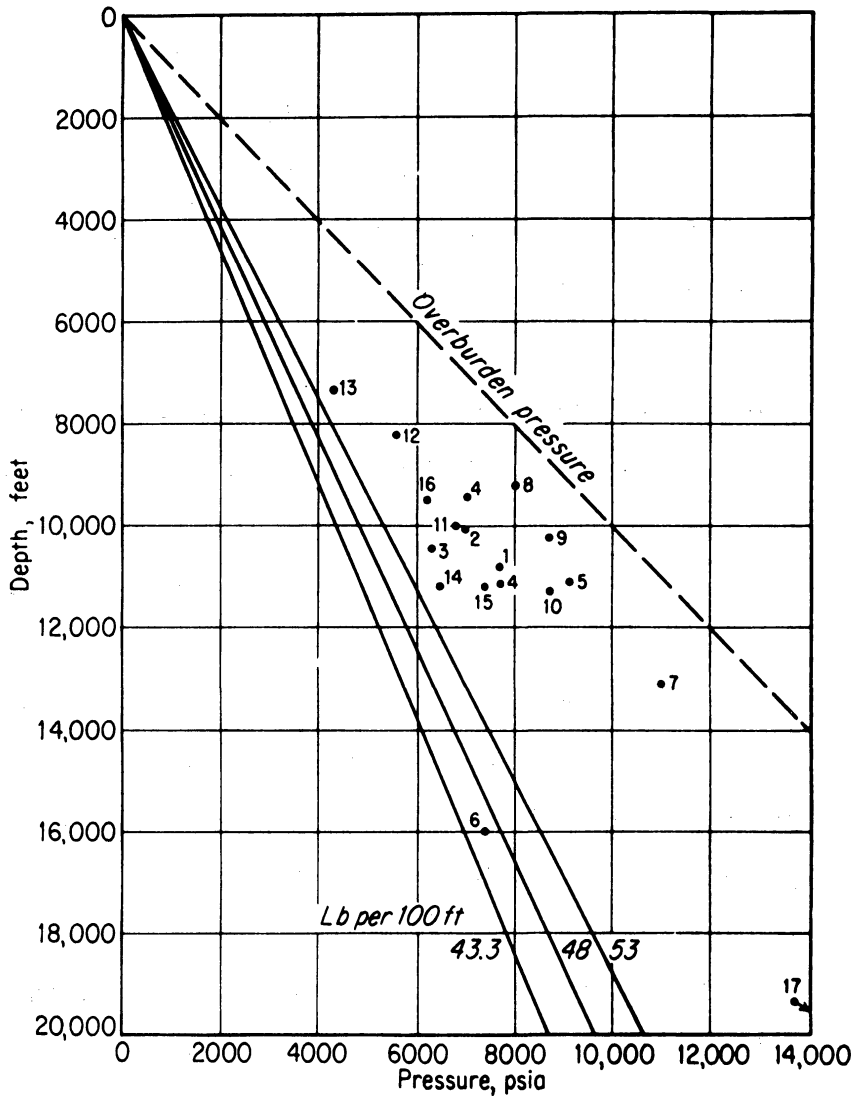


Fig. 3.1 Effect of depth on discovery pressures for various reservoirs.

and the low sides. Sometimes the abnormally high pressures are due to compaction of shales surrounding the strata bearing the hydrocarbons.

Abnormal pressures usually indicate that the particular reservoir fluids are not in communication with outer formations.

Because the number of moles that can be put in storage for a given reservoir volume is roughly proportional to the pressure in the reservoir and because the higher the storage reservoir pressure the larger will be the reservoir volume due to displacement of water from the underburden, "overpressuring" is a desired practice as long as it does not cause the cap rock to leak or break.

The effect of over-pressuring on the storage capacity of a reservoir is illustrated in Figure 3.2. The original gas water interface AB corresponds to the discovery pressure of the gas field. This interface is pushed down and more gas enters into storage if the gas reservoir is held at a pressure higher than the original discovery pressure. If the interface AB on the other hand, is pushed beyond the level CD, the gas may leak out across the "spill-point" indicated in the vicinity of point D. If the extent of over-pressuring is too high, the gas may leak vertically across the cap rock or even mechanically fracture the cap rock.

Leakage Across Cap rocks

Caprocks are continuous permeability barriers usually of shale and occasionally of sand stone and dolomites of very low porosity and permeability. It is believed and has been demonstrated on several occasions that the caprock is made impervious to fluid leakage across it by the pressure of water in its pores. Upon discovery of any reservoir, the cap rock is usually fully saturated with water and under no differential pressure gradient, except that due to the ordinary hydrostatic effect. When gas pressure is applied to the underside of the cap rock at a sufficiently high overpressure, the gas works its way to displace the water from some permeable channel and establishes communications with more porous and more permeable formations above. When this happens, a gradual drying of more channels occurs and leakage accordingly increases. Under these circumstances, the leak first appears to be a point sink but later becomes area distributed. If mechanical failure

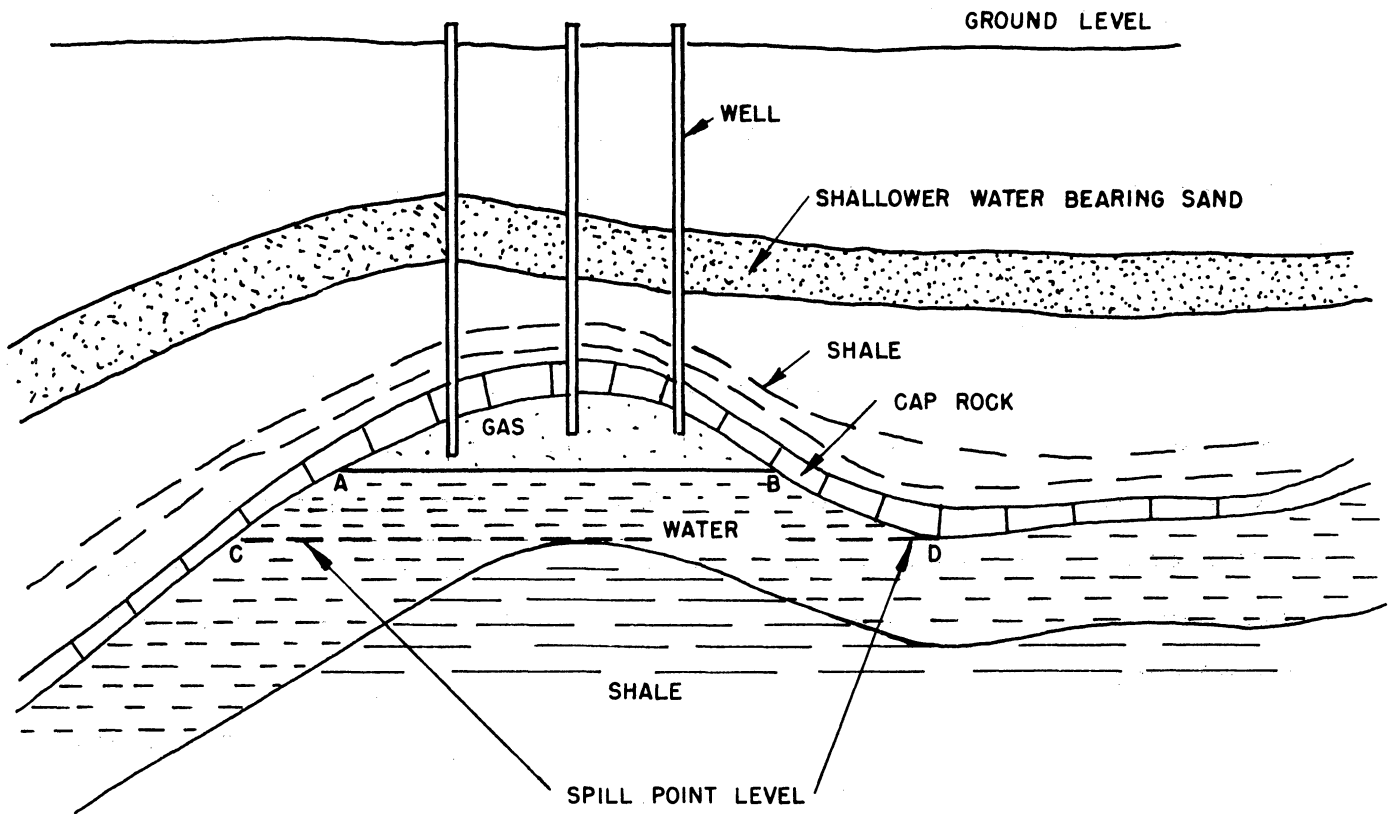


FIG. 3.2 EFFECT OF OVER PRESSURE ON STORAGE CAPACITY OF A RESERVOIR

of the rock occurs because of stresses involved in the porous matrix due to the gas pressure from below, the leak may first appear to be a line sink along the fracture curve but again soon becomes area distributed. It must be recognized at this point that very little is known at present concerning initiation, extent and nature of leaks across caprocks but studies are under-way to separate and study leak characteristics of cap rocks, both theoretically and in the laboratory.

Concept of Threshold Pressure

When a cap rock sample fully saturated with water is subject to gas pressure on one side, the leak does not occur so long as the pressure of the gas remains below some critical value. When it reaches this critical value, the water gets pushed out from the first permeable channel and leakage begins to take place. The pressure at which this phenomenon occurs is called the threshold pressure.

A bone dry core sample when partially submerged in water as indicated in Figure 3.3 will soak up the water by capillary imbibition. As the water rises through the pores, the saturation will adjust itself so that there is a distribution of saturation with height, resulting in the capillary pressure saturation curve indicated. If, on the other hand, a core fully saturated with water is left to drain by gravity and pressure on one side the capillary drainage curve AB will result. In drainage, all the water will not drain out as indicated by asymptotic approach to the irreducible water saturation S_i . If the core is let to soak up water by imbibition, again a different curve BC is observed. This phenomena is called capillary hysteresis.

On the drainage curve, the minimum pressure P_A necessary to reduce the saturation infinitesimally is called "the threshold pressure".

It must be noted that in order to have a quantitative basis for determining the safe limit on overpressuring and to assess the conditions which may lead to leakage one must have a clear understanding of capillary imbibition and drainage phenomena. Special equipment to measure these imbibition and drainage curves on core samples by measuring the vapor pressure of water above the core samples in a bell jar is now being constructed.

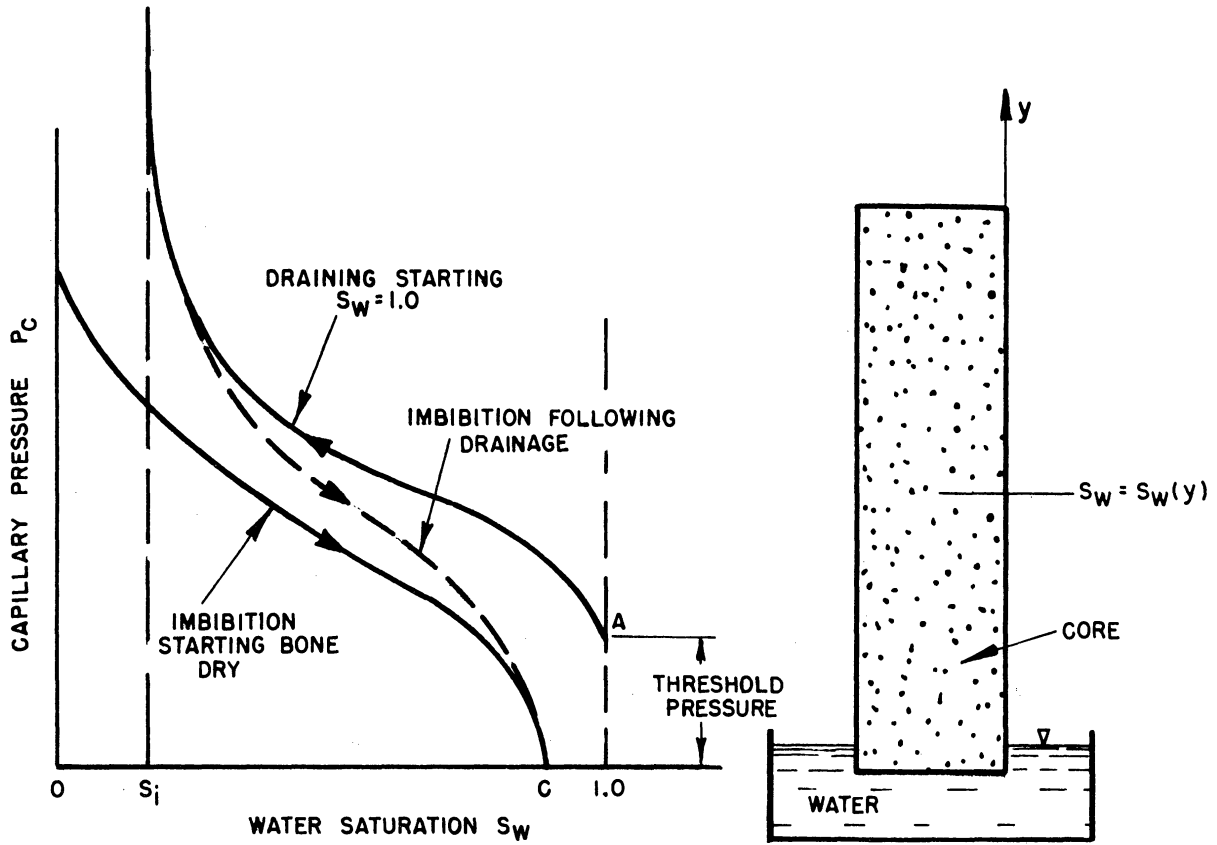


FIG. 3.3 IMBIBITION AND DRAINAGE CAPILLARY PRESSURE CURVES

Previous Theoretical Investigations

Previous work has largely been devoted to leakage effect when only a single phase (water, in particular) has been involved. For example, Hantush and Jacob^{3, 5-3, 11} have made extensive studies of the leakage of incompressible or slightly compressible fluids to and from horizontal storage reservoirs bounded above and/or below by less permeable layers. Although their interest was primarily in the addition of water to Artesian sand layers from the bounding strata, their solutions hold equally well for depletion or leakage.

Essentially, Hantush and Jacob studied various special cases of the differential equation (here stated in cylindrical co-ordinates) governing water motion in the aquifer:

$$\nabla^2 \Phi = \frac{\partial^2 \Phi}{\partial r^2} + \frac{1}{r} \frac{\partial \Phi}{\partial r} + \frac{\partial^2 \Phi}{\partial z^2} + \frac{1}{r^2} \frac{\partial^2 \Phi}{\partial \theta^2} = \frac{\phi \mu c}{k} \frac{\partial \Phi}{\partial t} \quad , \quad (3.1)$$

where Φ = flow potential (= $p + \rho g z$)

r = radial distance

z = vertical distance

θ = angle in horizontal plane

t = time

ϕ = porosity

μ = viscosity

c = compressibility

k = permeability

Frequently, in their analyses, the term $\partial^2 p / \partial z^2$ was neglected. The flow or leak in the less permeable bounding layers was assumed to be in a vertical direction and at a rate proportional to $(\Phi - \Phi^*)/A$, where Φ^* is a constant opposing potential and A is a constant depending on the permeability and thickness of these layers (or cap rock). This leakage rate appears, of course, as a boundary condition to equation (3.1) in the aquifer. By using Green's function and the method of images, Hantush and Jacob extended their results to a variety of geometries, which included infinite and finite

radial regions, infinite strips and quadrants, etc., under various types of boundary conditions.

Theis^{3.15} made an early investigation of the transient pressure in a non-leaking infinite plane radial region with a constant injection rate at the centre. The corresponding case with a leaking cap rock of semi-infinite vertical extent was one of the series analysed by Hantush^{3.11}, whose results for the aquifer pressure are represented by Witherspoon, Mueller and Donovan^{3.17} as a plot of p_D versus t_D , with β as a parameter, where

$$p_D = \text{dimensionless pressure increase, } \frac{2\pi kH\Delta p}{q\mu}$$

$$t_D = \text{dimensionless time, } \frac{kt}{\phi\mu cr^2}$$

$$\beta = \frac{r}{4H} \sqrt{\frac{k'\phi'c'}{k\phi c}}$$

Δp = increase of aquifer pressure above discovery pressure

H = aquifer thickness

q = volumetric injection rate

The superscript primes denote cap rock properties, and all quantities are assumed to be in consistent units. Note that the Theis solution corresponds to the case $\beta = 0$.

Witherspoon et al^{3.17} assert that, under practical conditions (in particular for a cap rock of low permeability), the value of β is so small as to cause no significant deviation in the aquifer pressure from that predicted for the no-leak case. They demonstrate, however, that pressure observations in the leaky cap rock itself afford a more sensitive method for determining the effectiveness of the cap rock as a barrier. Witherspoon et al. used an unspecified finite difference method which allowed for radial and vertical flow in both the aquifer and in the semi-infinite cap rock.

Their results were presented as plots of a ratio $\Delta p' / \Delta p$ versus \underline{H} , with α as a parameter, where

$\Delta p'$ = pressure changed in cap rock

Δp = pressure change in aquifer without leak

\underline{H} = dimensionless height above the bottom of the aquifer, z/H

$$\alpha = t_D r^2 k'/k \text{ (note this is not a dimensionless parameter)}$$

The Scope of Present and Future Theoretical Work

It will be observed from the above comments that previous studies on leaking caprocks have primarily considered the case of a single fluid (water) with the leak uniformly distributed over an area. Also, the concept of a "threshold pressure difference", below which there is no leak, does not appear to have been used widely.

Probably the most important questions that may be answered by a theoretical investigation are

- (1) How does a leak occur?
- (2) How can a leak be detected?
- (3) What is the performance of a reservoir whose cap rock properties have already been evaluated?

These problems will now be discussed in turn.

Firstly, it has already been mentioned that a leak may be produced by either (a) displacement of cap rock water by gas, or (b) mechanical failure of the cap rock due to excessive over-pressurizing. In the case of water displacement, it is unlikely that the gas/water interface advances in a piston-like manner. A slightly uneven distribution of permeability or porosity in the caprock will serve to initiate "fingering" or "channelling" of the gas. This phenomenon is likely to become accentuated because of the diminishing length of water column ahead of the "finger", although this effect may be partially offset by an increasing pressure gradient in the water as the local interface accelerates. It is possible that fingering may be minimized, and hence eventual leaking delayed, by a gradual rather than a sudden over-pressurizing. In the case of a sufficiently thick cap rock, the reservoir might possibly be operated over yearly cycles in such a manner that the gas/liquid interface always oscillates within the cap rock.

Secondly, the question of leak detection has partly been answered by Witherspoon et al. for the case of a cap rock of homogeneous texture. An obvious extension is to be the situation involving a non-homogeneous cap-rock. In such a case, the leaks may be localized and can be treated by assuming they behave approximately either as isolated point sinks or

(especially when caused by a fracture) as line sinks. The first step would be to postulate a particular type of leak and its location relative to an injection well and a set of observation wells. Note that the problem is now two-dimensional in horizontal extent alone. For a given injection schedule of either water or gas, the transient pressures in the observation wells may be predicted. By repeating for different leak models, a "case-book" of performances can be developed against which actual field behaviors might be checked and hence diagnosed. There is probably little hope (or even desirability) of being able to distinguish between (e. g.) a uniformly distributed leak and a number of point leaks themselves uniformly distributed.

The third question, that of predicting reservoir performance when the cap rock properties are known, is similar to the second, except that both water and gas are now definitely involved.

The key to answering the above three questions clearly lies in being able to predict the simultaneous motion of gas and water in porous media, viz in the aquifer and/or cap rock. It is true that certain problems may be treated in a simplified manner. For example, a study is currently being made of the performance of a leaking reservoir with given cap rock properties and a given injection/withdrawal schedule. The following assumptions are made:

- (a) Uniform pressure throughout the gas bubble.
- (b) Water movement can be predicted by the method of Van Everdingen and Hurst,^{3.16} also presented by Katz et al.^{3.13}
- (c) Leak occurs only above a certain threshold pressure.
- (d) Leak rate across cap rock is that predicted for steady state one dimensional flow.

More generally, however, the starting point will be the differential equations governing unsteady two-phase flow in a porous medium. An approximate treatment is to think of the gas and water forming two separate regions between which there is a distinct interface. In this case, equations of the type (3.1) will have to be solved in each region, together with a procedure for predicting the velocity of the moving interface.

In practice, the interface will probably be indefinite, due to an

incomplete displacement of water as the gas advances. It is convenient to deal in terms of a water saturation S , which may vary from zero (all gas) to unity (all water). The governing simultaneous partial differential equations, which result from unsteady material balances and the application of d'Arcy's law, are given by Douglas, Peaceman and Rachford^{3.3} as

$$\begin{aligned} \nabla k \frac{k_{rg}}{\mu_g} \nabla \Phi_g &= -\phi S' \left\{ \frac{\partial \Phi_g}{\partial t} - \frac{\partial \Phi_w}{\partial t} \right\} \\ \nabla k \frac{k_{rw}}{\mu_w} \nabla \Phi_w &= \phi S' \left\{ \frac{\partial \Phi_g}{\partial t} - \frac{\partial \Phi_w}{\partial t} \right\}, \end{aligned} \quad (3.2)$$

where k = permeability

k_{rg}, k_{rw} = relative permeabilities for gas and water.

μ_g, μ_w = gas and water viscosities

Φ_g = gas potential, $p_g + \rho_g gh$

Φ_w = water potential, $p_w + \rho_w gh$

ϕ = porosity

t = time.

In equations (3.2), S' denotes the derivative of the water saturation with respect to capillary pressure, and arises from an accumulation term $\partial S / \partial t$. This is permissible, since, by definition of capillary pressure,

$$P_c = P_g - P_w$$

i. e.

$$\frac{\partial S}{\partial t} = \frac{dS}{dp_c} \frac{\partial p_c}{\partial t} = S' \frac{\partial}{\partial t} (\Phi_g - \Phi_w).$$

(3.3)

Note that S' may depend on whether gas is displacing water, or vice versa, due to the hysteresis effect mentioned earlier.

It is obvious that any attempts to solve equations (3.2) by analytical means are likely to fail unless considerable simplifying assumptions are made. Rather, finite difference approximations to their solution are clearly indicated, and the implicit alternating direction method used by Douglas, Peaceman and Rachford^{3.3}, and also discussed earlier,^{3.1, 3.2, 3.14} is an obvious choice. It is also anticipated that the Dufort and Frankel^{3.4} method may be of utility.

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4. FRACTURING

Literature Survey and Design Calculation

When soil impermeation through application of grouting into porous materials such as sandstone is considered for creation of storage reservoirs the need to induce fractures to provide continuum for grouting materials becomes important. This is why it was pointed out in Chapter 1 that hydraulic fracturing can be of definite assistance in design and development of storage reservoirs. Once an underground formation has been fractured, grout can be injected into the fracture to provide an impervious layer. Grouted horizontal fractures may serve as caprock while grouted vertical fractures will act as walls to provide impervious boundaries around or amidst the permeable sandstone.

Hydraulic fracturing was first introduced to the petroleum industry in 1949 as a method of increasing oil well productivity. Since 1949, many methods and theories concerning fracturing have been proposed. Information dealing with fracturing occurs frequently in the literature, but it appears that no one has summarized the material to the extent that practical and realistic fracture calculations can be made. In order to provide a basis for the design of fractures in the creation of gas storage reservoirs, this paper presents methods of creating fractures, equations to calculate fracture extent, a discussion of fluids and propping agents to be used, along with a complete procedure for design.

Fracture Extent

The basic equation for fracture design was presented by Howard and Fast in 1957.^{1, 2}

$$A = \frac{Q_i W}{4\pi C^2} (e^{x^2} \operatorname{erfc}(x) + \frac{2}{\sqrt{\pi}} x - 1) \quad (4.1)$$

where

$$x = \frac{2C\sqrt{\pi t}}{W}, \text{ dimensionless time}$$

A = total area of one face of the fracture, ft²

Q_i = constant injection rate during treatment, ft³/min,
or (bbl/min)(5.614)

t = total pumping time, min.

W = constant fracture clearance or width, ft.

C = a constant which is a measure of flow resistance
of the fluid leaking off into the formation during
fracturing treatment, ft/(min.)^{0.5}

$\operatorname{erfc}(x)$ = complementary error function of x.

The fracturing fluid coefficient, C, in equation (4.1) is the rate of fluid loss from the fracture to the formation. There are three mechanisms which control rate of fluid flow into a formation. These are:^{1,2}

1. Fracturing fluid viscosity and reservoir permeability.
2. Viscosity and compressibility of reservoir-fluid.
3. Wall building effects.

Coefficients for mechanisms 1, 2, and 3 are calculated and the lowest value is taken as controlling. The coefficient for mechanism 3 is considered only when water loss additives are added in order to control fluid loss into the formation.

Fracturing fluid viscosity and formation permeability coefficient, C_I, is calculated as follows:^{1,2}

$$C_I = 0.0469 \sqrt{\frac{K \phi \Delta P}{\mu_F}}, \quad \frac{ft}{\sqrt{min}} \quad (4.2)$$

where

K = permeability of formation to fracturing fluid,
darcys

ϕ = porosity of formation, fractional quantity

ΔP = difference in pressure between the fluid at the
formation face and the fluid in the formation, psi

μ_F = viscosity of fracturing fluid, CP.

Equation (4.2) can be solved by the nomogram in Figure 4.1.

Reservoir fluid viscosity and compressibility effect, C_{II} ,
can be expressed by:^{1,2}

$$C_{II} = 0.0374 \Delta P \sqrt{\frac{K \phi C_F}{\mu_R}}, \quad \frac{ft}{\sqrt{min}} \quad (4.3)$$

where

C_F = compressibility of reservoir fluid, 1/psi

μ_R = viscosity of reservoir fluid, CP.

Equation (4.3) can be solved by the nomogram in Figure 4.2.

Note: Figure 4.2 has incorporated in it a compressibility of $1 \times 10^{-5} \text{ psi}^{-1}$, an approximate value for crude oils. If the actual compressibility of the reservoir fluid is significantly different from this, the C_{II} value obtained from the nomogram should be multiplied by $\sqrt{\frac{C_F(\text{true value})}{1 \times 10^{-5}}}$.

Wall building effect, C_{III} , is calculated as follows:^{1,2}

$$C_{III} = 0.0164 \frac{m}{a}, \quad \frac{ft}{\sqrt{min}} \quad (4.4)$$

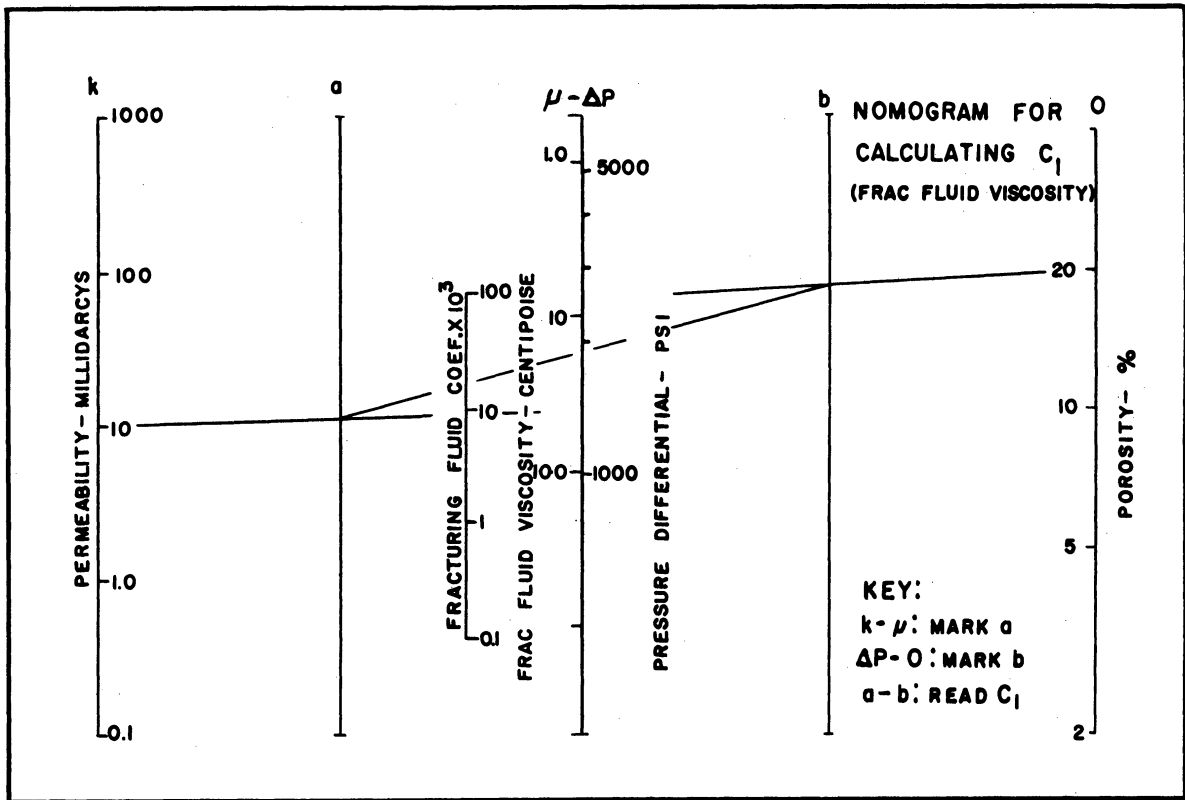


FIG. 4.1. NOMOGRAM FOR DETERMINATION OF C_1

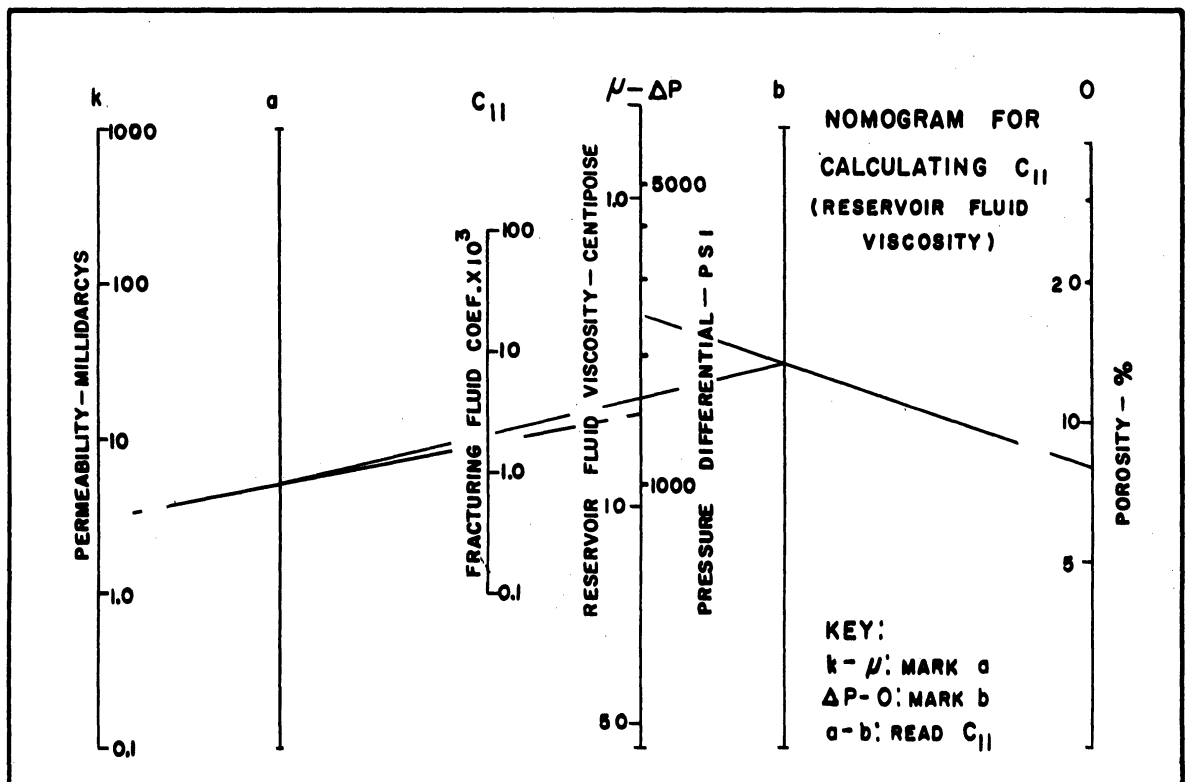


FIG. 4.2. NOMOGRAM FOR DETERMINATION OF C_{II}

where

m = slope of experimental fluid loss line when cm^3
fluid loss is plotted versus $\sqrt{t(\text{time})}$, $\text{cc}/\sqrt{\text{min.}}$
 a = area of filter medium, cm^2 .

The fluid loss test is carried out in a filter press which consists of a pressure cell with one end containing filter paper or a thin core wafer. A standard pressure difference, e.g., 1000 psi, is applied across the cell and the volume of filtrate collected is recorded as a function of time. A sample fluid loss test is shown in Figure 4.3. The test must be corrected to the actual reservoir pressure difference, ΔP . Figure 4.4 is used to make this correction of C_{III} , based upon the relationship that fluid loss through a filter is proportional to the pressure difference. These fluid loss tests almost always give a positive intercept at time equals zero, as indicated in Figure 4.3. A method for including this spurt loss in calculating fracture area will be presented below.

The solution to equation (4.1) can be simplified and put in nomographic form in the following manner. By rearrangement, it is possible to express equation (4.1) in the form:³

$$A = \frac{V}{W} E \quad (4.5)$$

where

A = total area of one face of the fracture, ft^2
 V = volume of fracturing fluid pumped, ft^3
 W = width of fracture, ft
 E = efficiency, the volume of fracture created
expressed as a fraction of the volume of fluid
pumped. E is a function only of x .

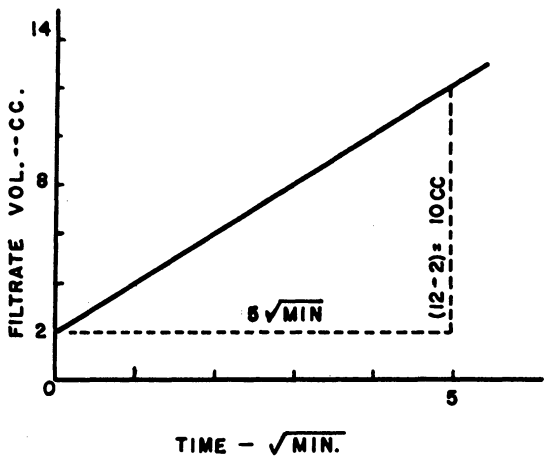


FIG. 4.3 FLUID LOSS TEST RESULTS

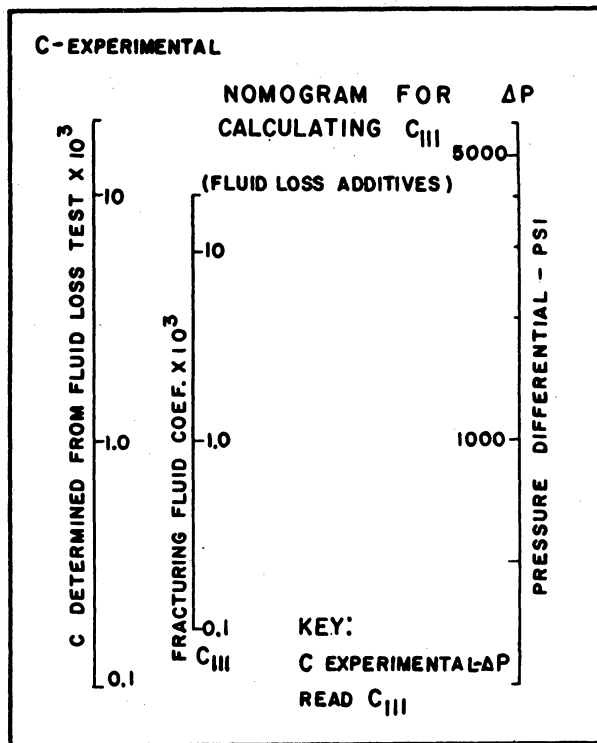


FIG. 4.4 NOMOGRAM FOR DETERMINATION OF C_{III}

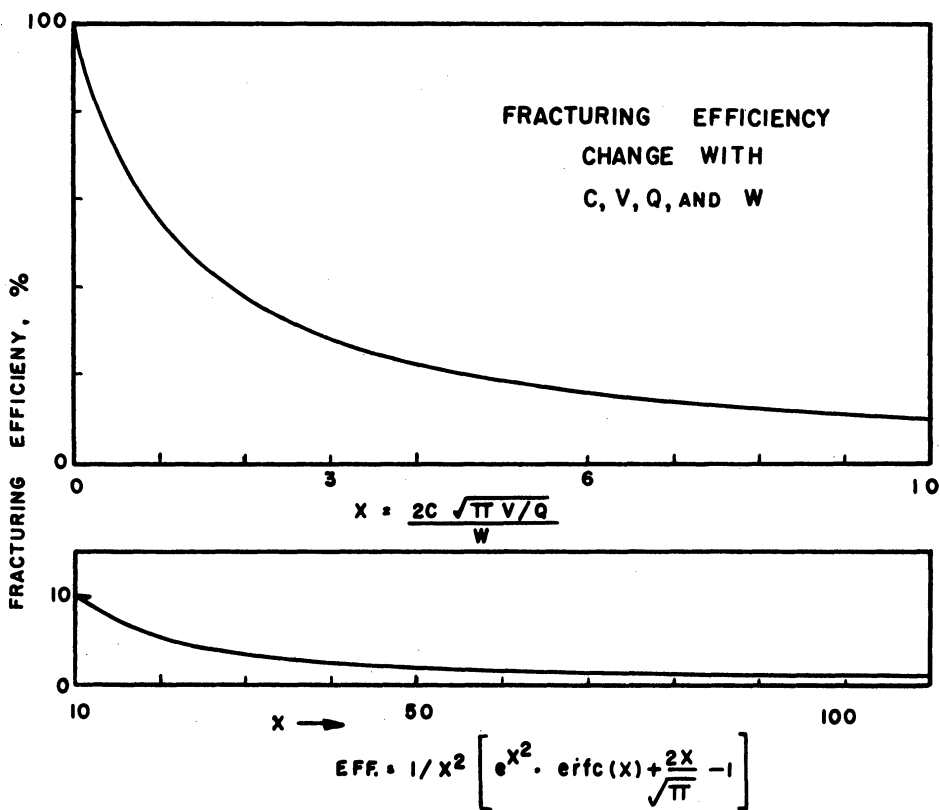


FIG. 4.5 FRACTURING EFFICIENCY VERSUS X

A plot of efficiency versus x is presented in Figure 4.5. Efficiency as a fraction is calculated from the equation:

$$E = \frac{1}{x^2} \left[e^{x^2} \operatorname{erfc}(x) + \frac{2x}{\pi} - 1 \right] \quad (4.6)$$

Figure 4.6 presents a nomographic solution for efficiency and then allows solution of equation (4.5) for fracture area.

Fracture Width

The preceding equations for fracture area depend upon the knowledge of the fracture width. Perkins and Kern⁴ have developed a method for the determination of fracture widths. One case considered by Perkins and Kern was that of a vertical fracture created from Newtonian fluids in laminar flow. The condition for laminar flow exists when the Reynolds number is less than $(7.81 \times 10^3)(0.32) = 2500$, where

$$N_{RE} = 8.70 \times 10^3 \frac{(Q)(\text{SpGr})}{(H)(\mu)} \quad (4.7)$$

It must be noted that in Eq. (4.7) the numerical constant 8.70×10^3 has the dimensions of density (i.e. mass/cubic length).

N_{RE} = Reynolds number

Q = total injection rate, bbl/min.

SpGr = specific gravity of fracturing fluid

H = height of fracture, ft.

μ = viscosity of fracturing fluid, cp.

When the condition for laminar flow is satisfied, equation (4.8) applies.

$$W = 0.38 \left[\frac{(Q)(\mu)(L)}{E} \right]^{1/4} \quad (4.8)$$

where

W = maximum crack width at the well bore, in.

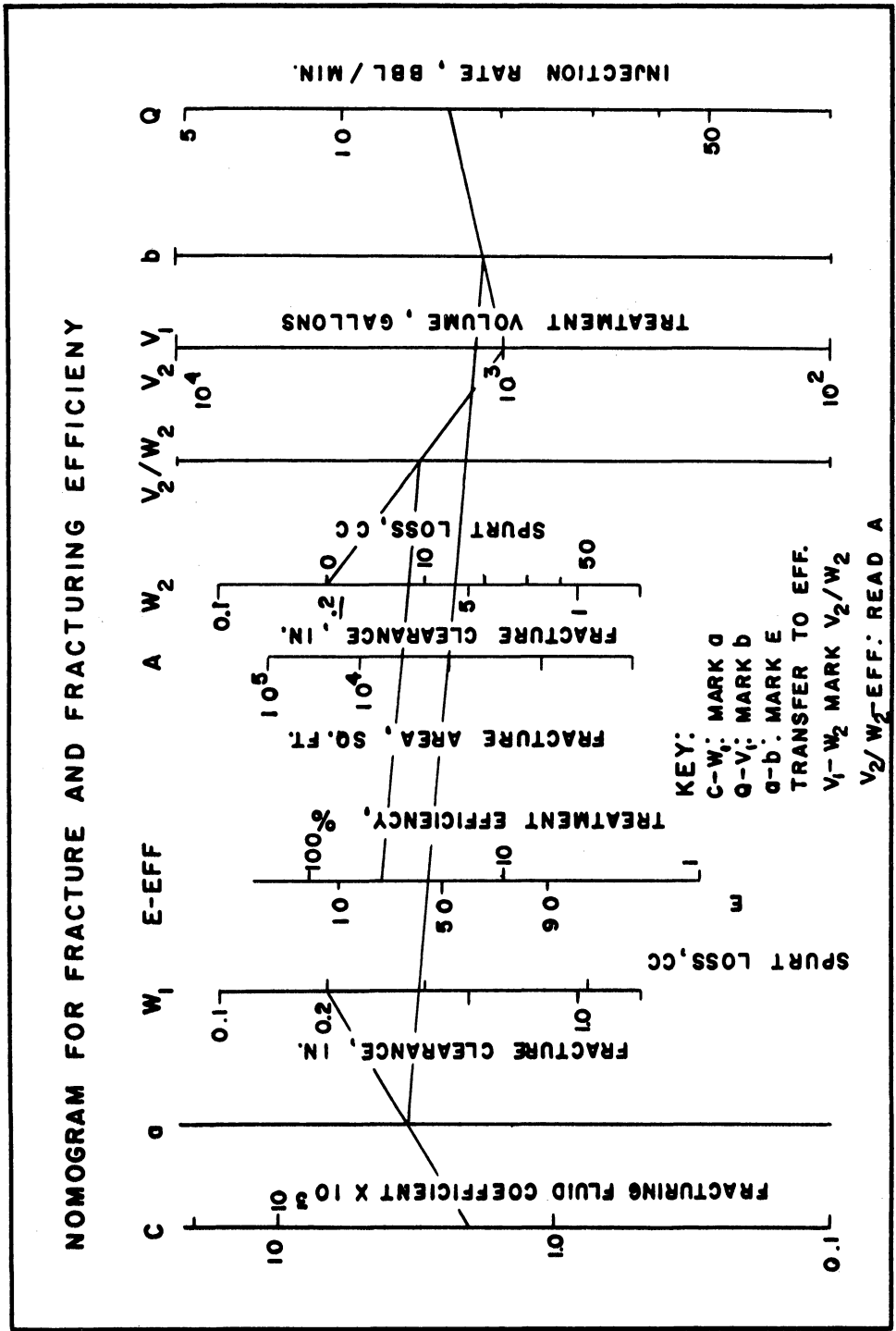


FIG. 4.6 NOMOGRAM FOR DETERMINATION OF FRACTURING EFFICIENCY AND FRACTURE AREA.

Q = total pump rate, bbl/min.

μ = effective fracturing fluid viscosity, cp.

L = length of a vertical fracture measured from the well bore, ft.

E_Y = Young's modulus of formation rock, psi.

(values presented in Table 4.1)

This equation is presented graphically in Figure 4.7. In the case of a homogeneous formation, the crack would take the shape of a disc making $L = 1/2 H$. This is illustrated in Figure 4.15. However, if a very tight layer is within the potential fracture radius, the fracture will be restricted yielding different values for H and L .

If $(Q)(SpGr)/(H)(\mu)$ is greater than 0.32, then the fluid will be in turbulent flow within the fracture. For this case, the width is given by equation (4.9).⁴





$$W = 0.6 \left[\frac{(Q)^2 (SpGr)(L)}{(E_Y)(H)} \right]^{1/4} \quad (4.9)$$

This equation is presented graphically in Figure 4.8.

If non-Newtonian fluids such as gelled oils or emulsions are used, then it is necessary to determine the fluid's flow properties before estimating crack width. From Fann meter (measures shear stress as a function of shear rate) data, two constants, k' and n' , are determined and these constants used in place of viscosity.⁴ Once k' and n' have been determined, crack widths can be estimated from Figure 4.9.

If a fracture is oriented horizontally, crack width may result from two types of rock movement. If the fracture is deep

LEGEND:

-  UNCONSOLIDATED TO LIGHTLY CONSOLIDATED SANDSTONE
-  MEDIUM SANDSTONE
-  HARD SANDSTONE
-  LIMESTONE AND DOLOMITE

USE THIS CHART IF:
 $\frac{(Q_{BPM})(Sp.Gr.)}{(H_{FT.})(\mu_{CP.})} < 0.32$

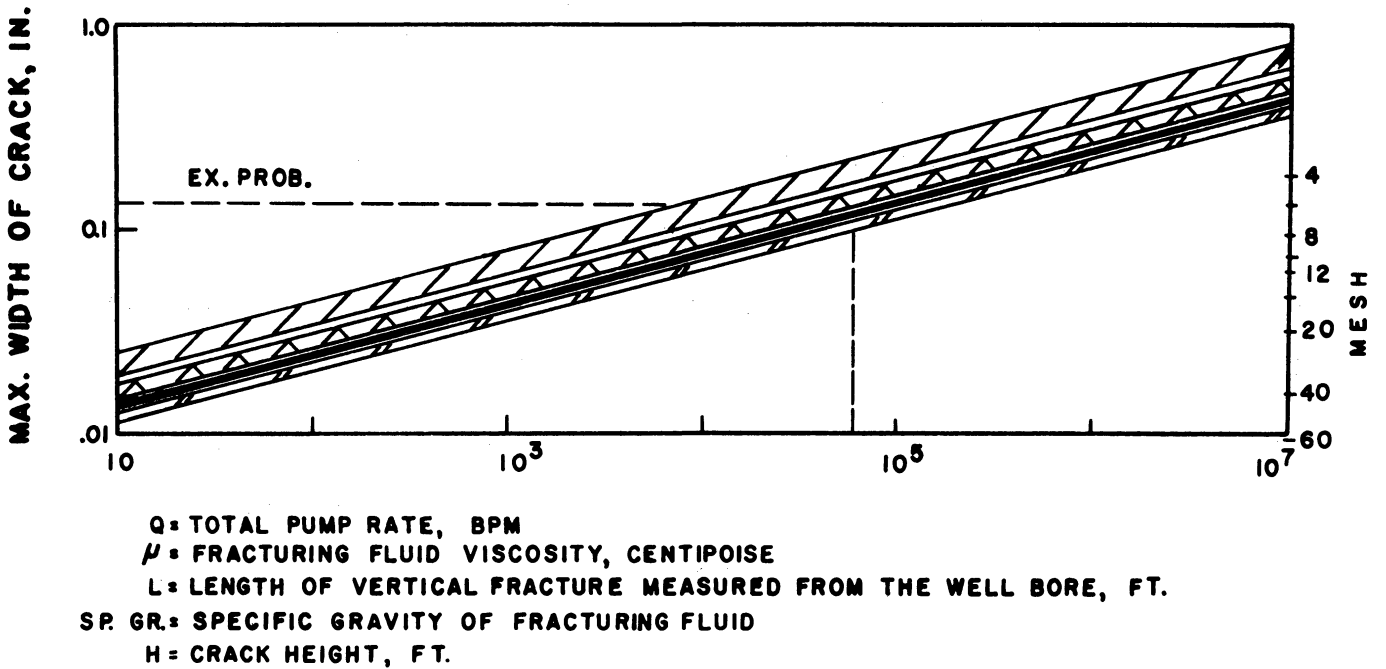


FIG. 4.7-CRACK WIDTHS FOR RESTRICTED VERTICAL FRACTURES RESULTING FROM NEWTONIAN FLUIDS IN LAMINAR FLOW.

LEGEND:

-  UNCONSOLIDATED TO LIGHTLY CONSOLIDATED SANDSTONE
-  MEDIUM SANDSTONE
-  HARD SANDSTONE
-  LIMESTONE AND DOLOMITE

USE THIS CHART IF:
 $\frac{(Q_{BPM})(Sp.Gr.)}{(H_{FT.})(\mu_{CP.})} > 0.32$

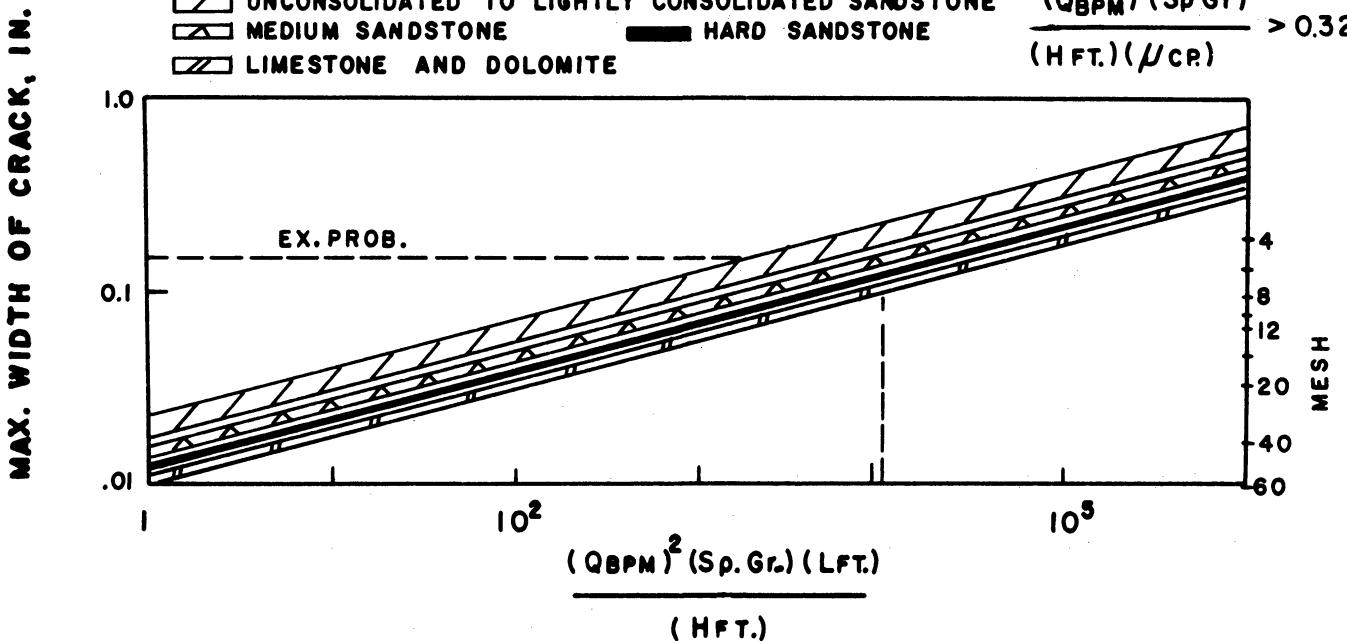
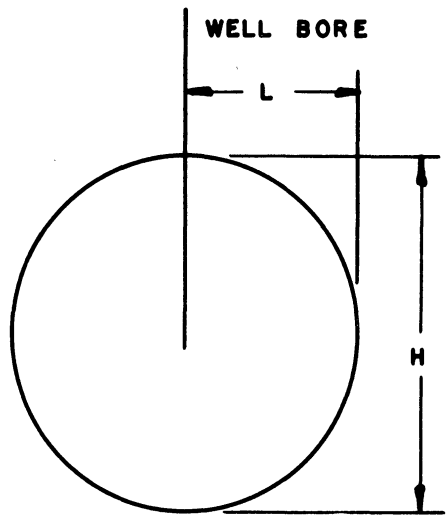
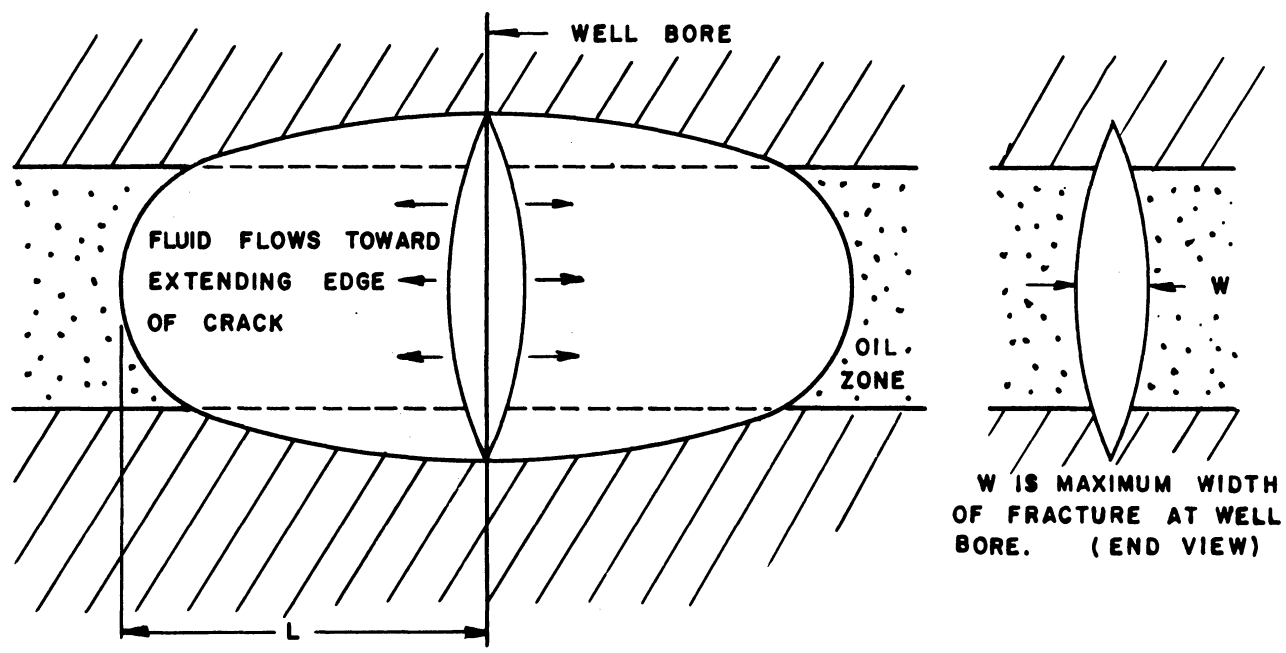


FIG. 4.8-CRACK WIDTHS FOR RESTRICTED VERTICAL FRACTURES RESULTING FROM NEWTONIAN FLUIDS TURBULENT FLOW.



UNRESTRICTED VERTICAL FRACTURE



RESTRICTED VERTICAL FRACTURE

FIG.4.15 RESTRICTED AND UNRESTRICTED VERTICAL FRACTURES.

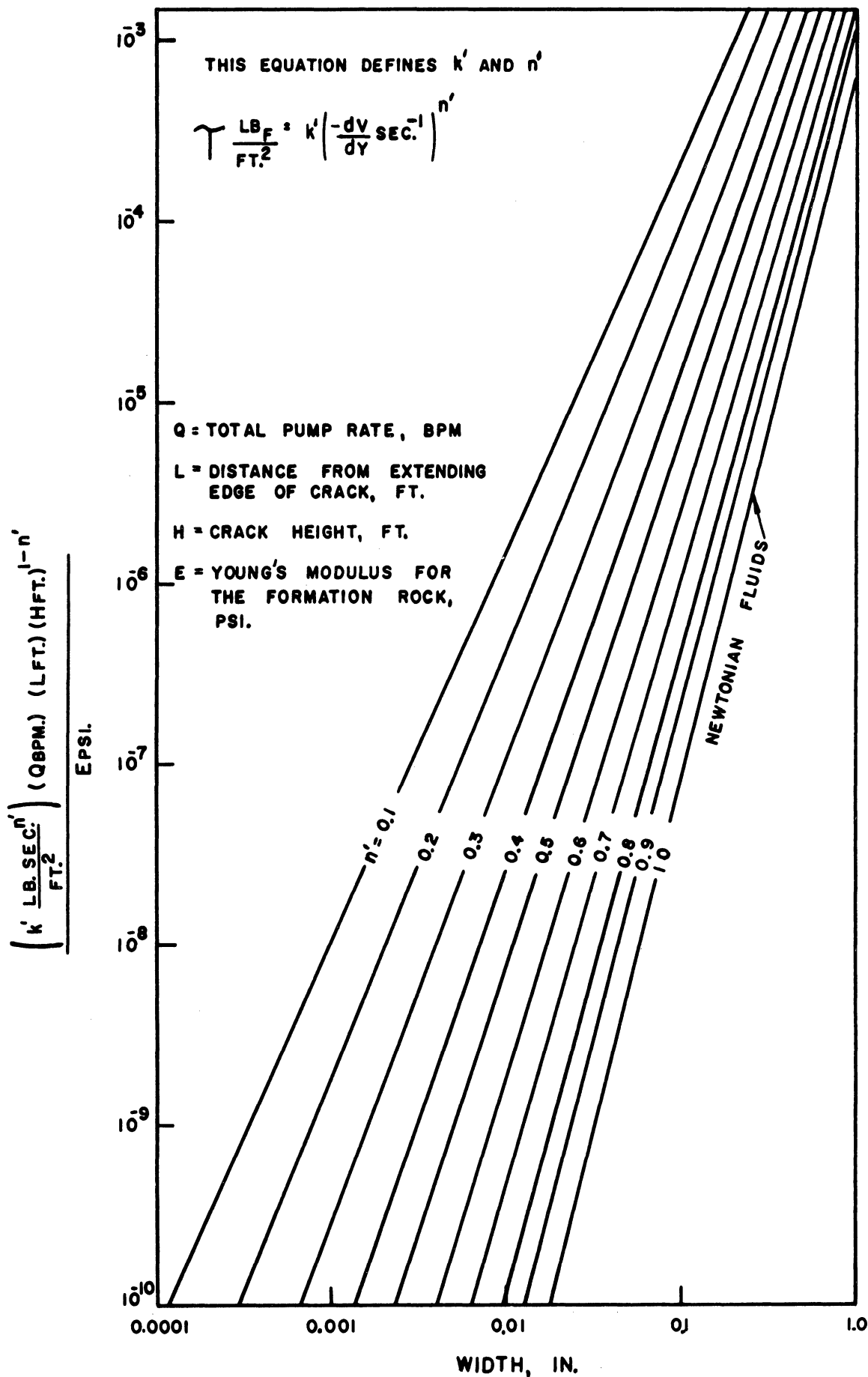


FIG. 4.9 CRACK WIDTHS FOR RESTRICTED VERTICAL FRACTURE RESULTING FROM NON-NEWTONIAN FLUIDS IN LAMINAR FLOW.

within the earth, cracks result principally from compression of rock in the vicinity of the fracture. However, if the fracture is very shallow, crack width may also result from flexing and lifting of the overburden. It has been shown⁴ that compression of surrounding rock is the principal mechanism leading to crack width if the depth is greater than about three-fourths of the fracture radius. Therefore, this is the mechanism that controls during most fracture treatments. For this condition the width is given approximately by equation (4.10).⁴

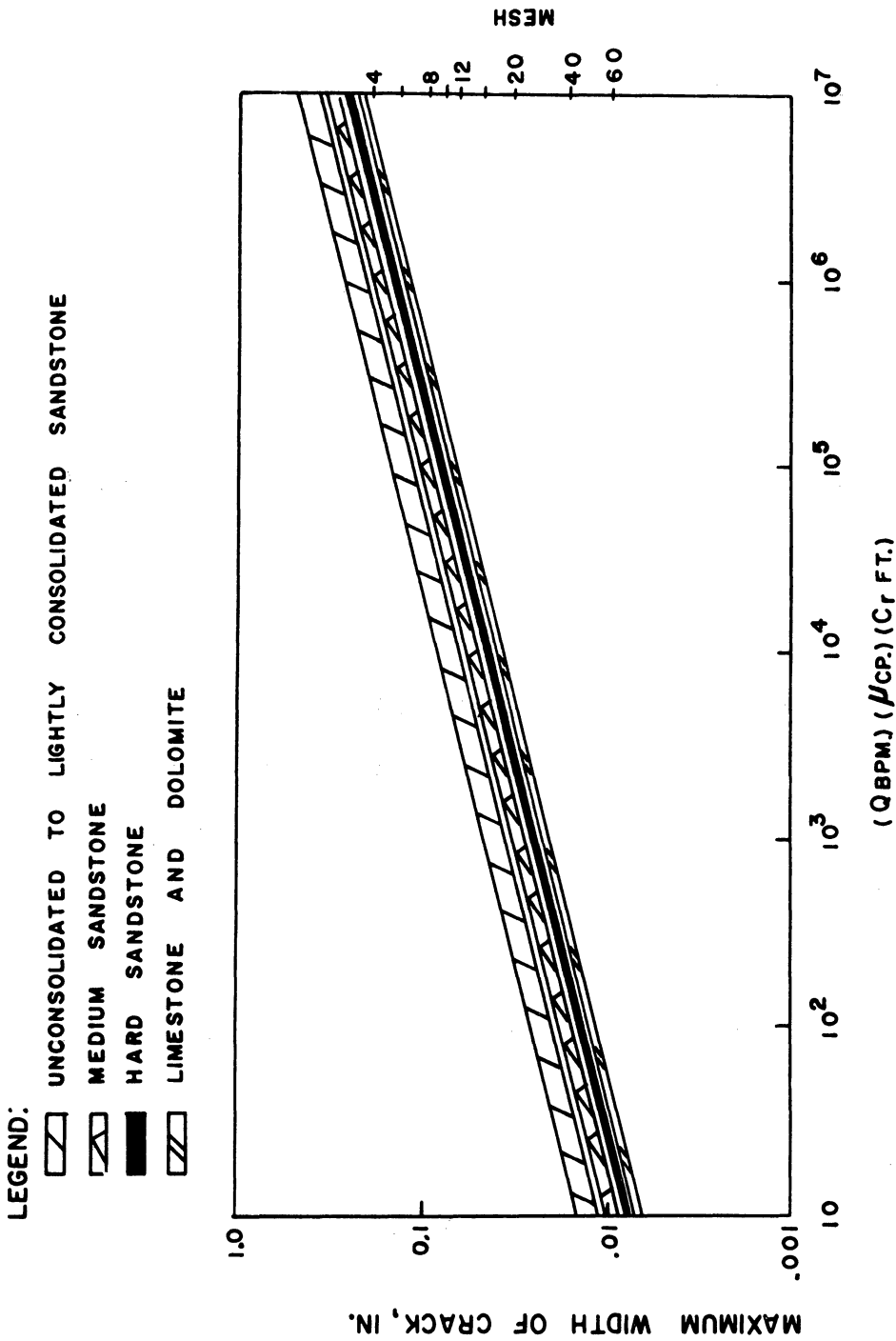
$$W(\text{in.}) = 0.22 \left[\frac{Q(\text{bbl/min})\mu(\text{cp})C_Y(\text{ft})}{E(\text{psi})} \right]^{1/4} \quad (4.10)$$

where

C_Y = radius of fracture, ft.

Figure 4.10 presents this equation graphically. Laminar flow of the fluid at every point in a horizontal fracture is probably encountered only rarely in field operations. Hence, turbulent flow must also be considered before a generally applicable equation can be derived. However, the turbulent zone usually will not extend far from the well bore; therefore, Figure 4.10 is approximately correct in most cases.⁴

The crack widths estimated from Figures 4.7, 4.8, 4.9, and 4.10 apply when pure fluids are being pumped along a fracture. These estimated widths are also valid when there is a sparse distribution of propping agent suspended in the fluid. However, if a large amount of sand is injected as a propping agent, then its presence in the fracture will influence pressure drop and thereby crack width.⁴ The following equation will give the average slurry



Q TOTAL PUMP RATE, BPM

μ = FRACTURING FLUID VISCOSITY, CENTIPOISES

C_r FRACTURE RADIUS, FT.

FIG. 4.10 APPROXIMATE CRACK WIDTHS FOR HORIZONTAL FRACTURES RESULTING FROM NEWTONIAN FLUIDS IN LAMINAR FLOW.

concentration taking into account fluid leak-off.

$$C_S = \frac{V_S}{(W)(A)} \quad (4.11)$$

where

C_S = slurry concentration vol/vol

V_S = volume of sand injected into fracture, ft³

A = fracture area, ft²

W = fracture width, ft.

The average slurry viscosity can then be estimated from Figure 4.11. The crack width is then estimated from Figures 4.7, 4.8, 4.9, or 4.10 using the average slurry viscosity and density rather than the viscosity and density of the pure fracturing fluid. In the actual case, slurry properties vary from point to point in the fracture. Hence, the width calculated as just shown must be interpreted only as an approximate width.

If it is desired to include the spurt loss, V_{Sp} , in the calculation of fracture area, it may be done by including this value as an increased fracture clearance^{1,2} where:

$$W' = W + \frac{V_{Sp}}{15.25 a} \quad (4.12)$$

where

W = fracture width, ft

V_{Sp} = spurt loss in cm³

a = filter area, cm²

A group of Russian engineers⁵ have advanced theories concerning the initiation and development of fractures. However, there appears to be a controversy as to the validity of their

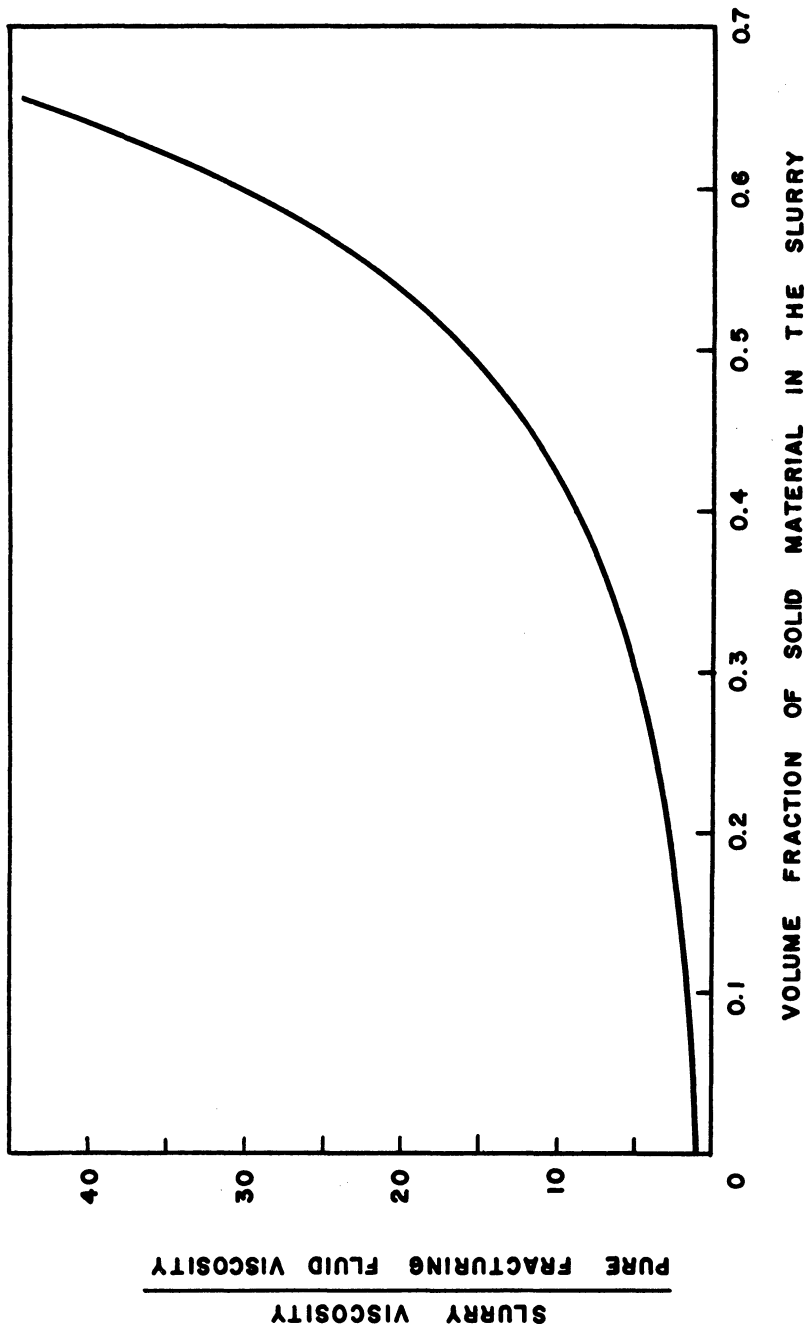


FIG. 4.11 VISCOSITY OF A SLURRY CONTAINING SUSPENDED SOLID MATERIAL COMPARED TO THE VISCOSITY OF THE BASIC FLUID.

approach, and for this reason these equations have been omitted from the discussion.

Pressure and Horsepower Requirements

Other important factors in the design of a fracturing job are the pressure and horsepower requirements. Surface pressure requirements to create and extend a fracture may be divided into two basic categories; breakdown and treating pressure.⁶ The breakdown pressure is dependent on several variables such as formation face contamination (filter cake, cement, etc.), existence or absence of formation fractures, bedding planes, rock strength and type, etc. and generally cannot be predicted accurately. However, since injection rates are not significantly important during breakdown other than insuring that the formation has ruptured, horsepower requirements are normally computed using predicted treating pressures and injection rates.

Treating pressure or pump pressure (P_s) requirement is equal to the sum of the hydraulic pressure (P_r) required to maintain fracture parting plus fluid friction losses (P_f) minus the hydrostatic fluid head (P_h), or

$$P_s = P_r + P_f - P_h \quad (4.13)$$

The pressure required to maintain fracture parting and extension (P_r) may be estimated as 1 psi/foot of depth to approximately 5,000 feet and 0.7 psi/foot of depth for deeper formations. A minimum pressure requirement of 0.6 psi/foot of depth may be estimated for all depths. Pressure losses due to friction (P_f) in the conductor pipe and through the perforations (if any) are dependent on fluid viscosity, injection rate, sand concentration and size of conductor pipe and may be estimated from charts

available from fluid supplies such as those appearing in Figure 4.12. Many fluid friction charts do not account for the sand content of the fluid and an approximate correction for sand can be made by increasing friction losses of sand-laden fluids by 8.0%/lb of sand per gallon.⁶ Static fluid head may then be obtained from Figure 4.13. P_s can then be calculated from equation (4.13).

The choice of a good injection rate is also important for a successful fracture treatment. Recommended injection rates for various sized tubing are given in Table 4.2.

After the injection pressure and the injection rate have been determined, equation (4.14) can be used to give the hydraulic horsepower requirement.

$$\text{HHP} = 0.0245 P_s V_i \quad (4.14)$$

where

P_s = injection surface pressure in psi.

V_i = injection rate in bbl/min.

Fracturing Fluids

Another important factor in the design of fracture treatments is the selection of a good fracturing fluid. Some basic requirements for a fluid are as follows:⁶

1. Must be able to physically open and extend a fracture.
2. Must be capable of carrying a "propping" agent which can be left in the formation to prevent "healing" of the fracture.
3. Should be easily back-flushed from the formation.
4. Should be compatible with native formation fluids.
5. Should create a minimum of permeability damage within the formation.
6. Should have low friction-loss properties and be easily pumped.

Fracturing fluids may be divided into three basic categories,

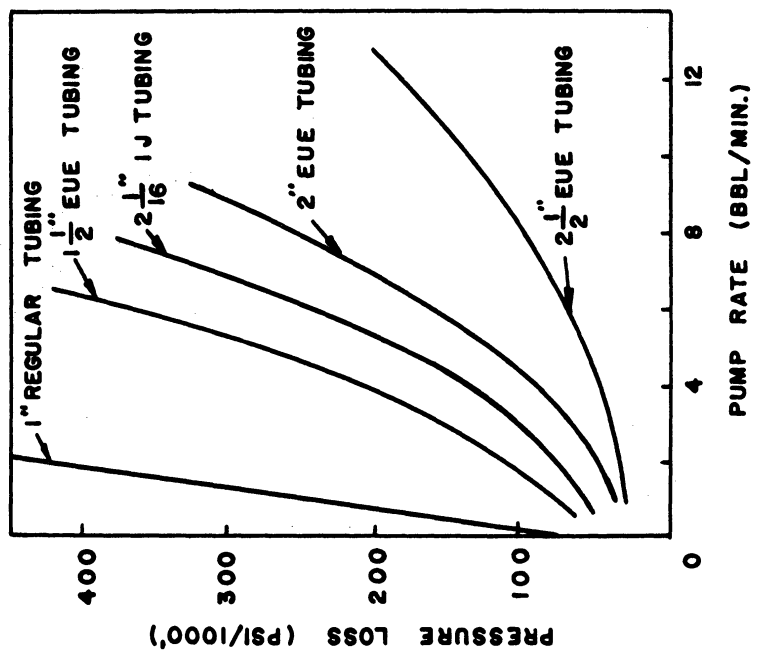
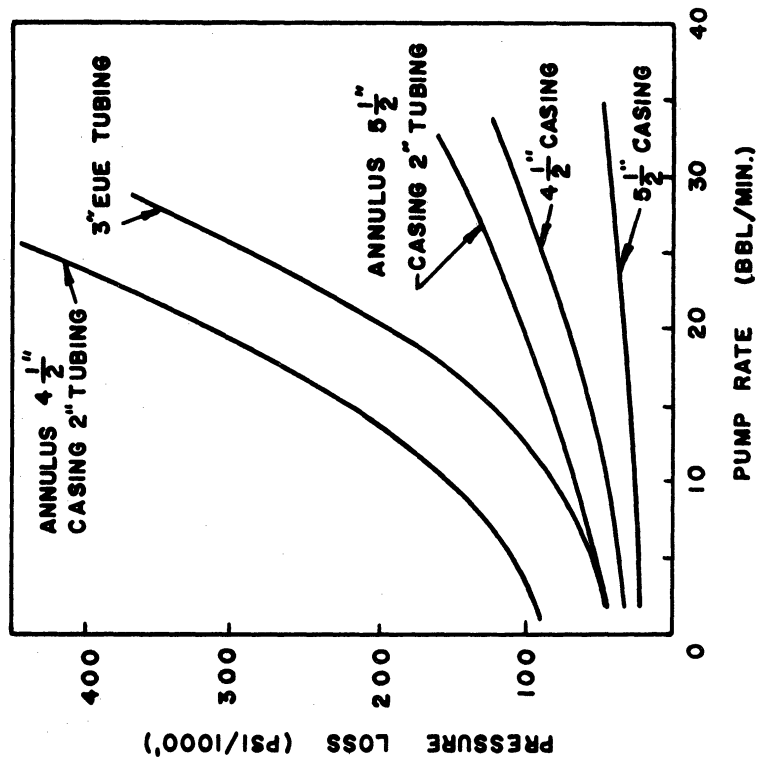


FIG. 4.12 PRESSURE LOSS DUE TO FLOW OF DOWELL'S WATERFRAC 60 THROUGH VARIOUS CONDUITS.

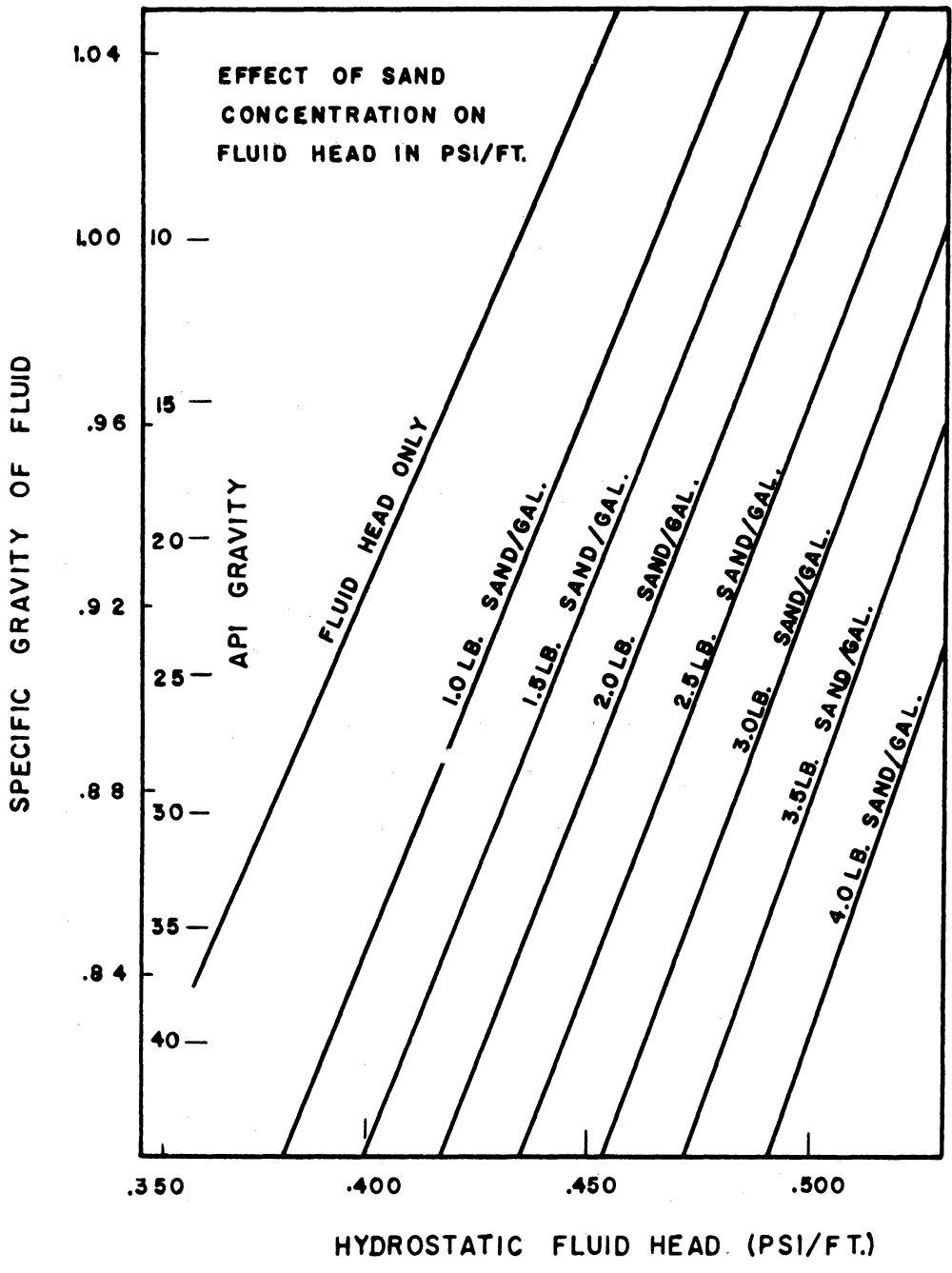


FIG. 4.13

water, oil, and acid.

Although water is the cheapest of the fracturing fluids, its use usually is restricted to treatments where emulsions or swelling clay minerals are not considered to be a problem. Even if swelling is not a problem, use of unmodified water should be restricted to treatments in which high injection rates are obtainable.⁶

One method to modify water is to add fluid loss control additives to inhibit fluid loss from the fractures formed and thereby increase the efficiency of the hydraulic fluid as a "prying" agent in opening and extending a fracture. Water may also be gelled to increase sand suspension ability without increasing effective viscosity.⁶ Gels usually exhibit high apparent viscosities when measured in a laboratory; however, their effective viscosity decreases rapidly with increased flow rates. Special chemicals such as surfactants, bentonite and clay swelling inhibitors, emulsion breakers, precipitate solvents, etc., are sometimes added to gelled and ungelled water and are used if laboratory tests justify the additional expense.

Oil is the most common fluid used in fracturing operations because of its compatibility with most reservoir fluids and good sand-carrying ability. Both refined oil and lease crudes are used and are modified in the same manner as water. Figure 14 illustrates the effect of water loss additives on lease crude fluid loss.

Gelled or ungelled acid is a common fracturing fluid in some areas for hydraulically fracturing carbonate reservoirs or carbonate bearing sandstones. One technique⁷ involves the addition

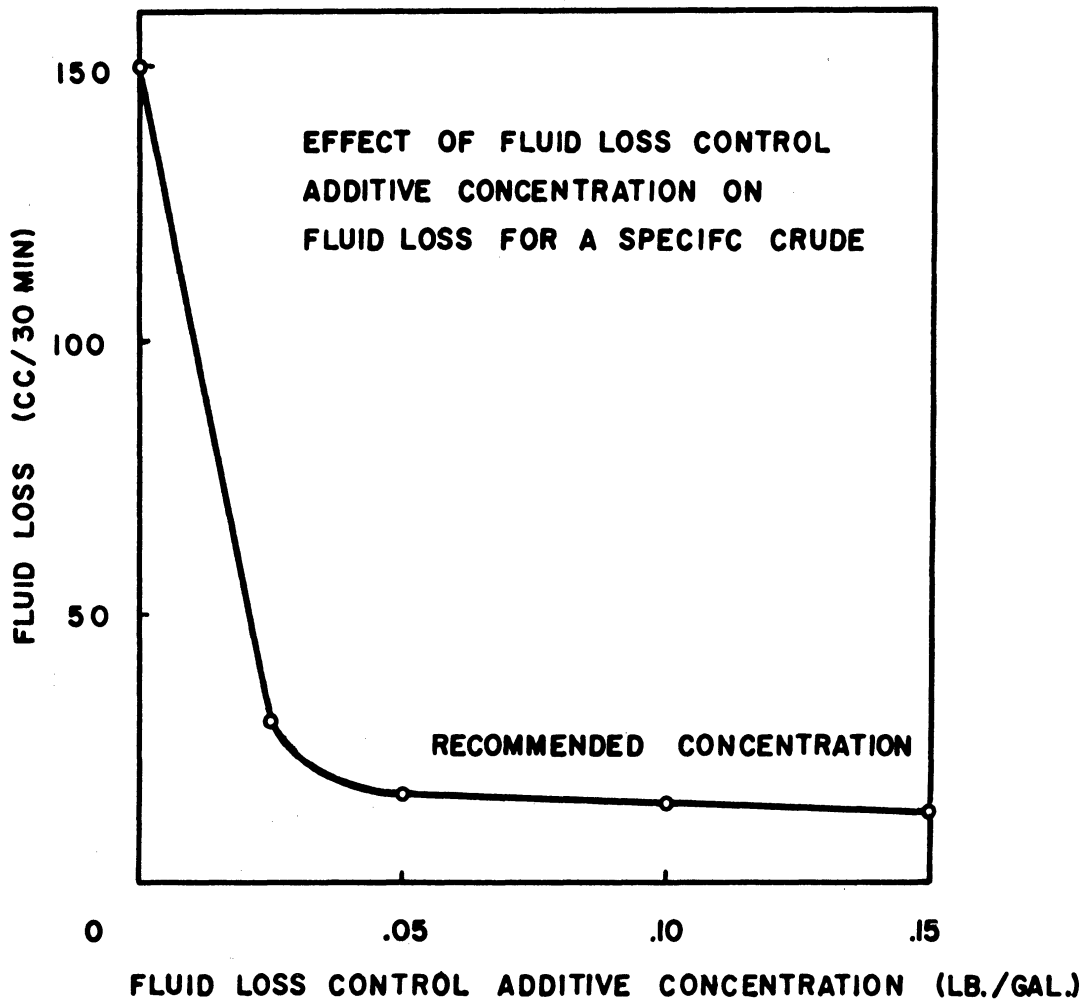


FIG.4.14

of dry crystals of sulfanic acid to the fracturing fluid. Because of the additional expense involved, acid treatment is not normally used if other fluids can be satisfactorily applied.

In fracturing to create a gas storage reservoir, it may be more expedient to use chemical grout as the fracturing fluid. Then, after the fracture has been opened and propped, the grout would set to provide an impervious boundary. The addition of water loss additives to a viscous chemical grout would probably be sufficient to give the added properties necessary to make the solution a fracturing fluid as well as a grouting material.

Propping Agent

The evaluation and selection of the fracture propping agent is also an important part of fracture treatment design. The main propping agent is sand although aluminum pellets^{10,12} and crushed walnut shells^{8,11} are used occasionally and have proved satisfactory. Most of the papers presented on propping agent selection, however, have been concerned with the propping agent concentration for maximum fracture flow capacity in oil well stimulation.¹³ However, in the creation of an underground storage reservoir, this evaluation probably would be less important. For the purpose of this investigation, the amount of sand needed can be taken as 4.4 lb sand/gal. of fracture volume created.³ In deep wells with high overburden pressure and/or soft formations, it may be desirable to use more sand. The maximum amount that can be added is that which will fill the entire volume of fracture created. The amount of sand necessary to "sand pack" the fracture is obtained by multiplying the recommended value by 2.7.³ When and if a fracture field test is made, a method exists for determining the injection schedule for a fracture treatment⁹ (i.e.,

the time and amount of fluid and propping agent injection).

The conventional well bore preparation for fracturing has been to use a perforated pipe, thus creating many small fractures on application of pressure. The method, however, probably would not provide satisfactory control of the location of the fracture in creating fractures for soil impermeation through grouting. Several new techniques, however, allow selective fracturing. One method involves the use of high velocity projectiles¹⁴ to start the fracture, thus providing a weak point for the hydraulic pressure to initiate the fracture. Another method involves the use of an evacuated cylinder that implodes under the hydraulic pressure¹⁵, and thus causes a sudden burst of very high pressure as the fluid in the pipe accelerates to fill the volume previously occupied by the cylinder. Still another method consists of notching the well bore to allow single-point entry.¹⁶ Another method involves the injection of small rubber balls into the well.¹⁷ As pressure is applied, the balls are pushed into the perforations thus preventing a fracture in that section of the well.

Some data have been published in the literature¹⁸ to aid in the calculation of the cost for a fracturing job. Table 4.3 gives the cost of oil fracturing fluid with water loss additives (C_{III} values are also listed for the oils). One dollar per hydraulic horsepower can be assumed for pumping cost.¹⁸

Design Procedure

1. Select propping agent, fracturing fluid, tubing size, pumping time.
2. Run a fluid loss test and use the results to plot filtrate volume versus $\sqrt{\text{time}}$.
3. Use the recommended injection rate, V_i , from Table 4.2.
4. Knowing the depth, calculate P_r (1 psi/ft at depths less than 5,000 ft).
5. Obtain friction loss, P_f , from a graph such as Figure 4.12 (also can be calculated via Reynolds Number and friction factor).
6. Obtain static fluid head, P_h , from Figure 4.13.
7. Calculate P_s from equation 4.13.
8. Calculate horsepower requirement by equation 4.14.
9. Calculate ΔP . ($\Delta P = P_r - P_g$ where $P_g = \frac{\rho}{\rho_c} h$ = formation pressure).
10. Calculate C_I by Figure 4.1.
11. Calculate C_{II} by Figure 4.2.
12. Calculate C_{III} by equation 4.4 and Figure 4.4.
13. Select the lowest of these (C_I , C_{II} , or C_{III}) as the controlling mechanism.
14. Compute the total volume pumped ($V = V_i t$).
15. Guess a fracture width (probably in the range 0.1 - 0.4 in.).
16. Correct the width for spurt loss by equation 4.12.
17. Use Figure 4.6 to determine the fracture area.
18. Calculate the fracture radius from the area.
19. Calculate N_{RE} (Reynolds Number) from equation 4.7 if the fracture is to be vertical.
20. Calculate W from Figures 4.7, 4.8, 4.9, or 4.10 using the slurry properties determined using equation 4.11 and Figure 4.11.

21. If the calculated width varies significantly from the assumed width, guess a new width and repeat steps 13 -17.
22. Compute the cost using Table 4.3 and using one dollar per hydraulic horsepower.

Example Problem

Data:

- | | |
|---------------------------------------------------------------------------------------------------------------------------|-------------|
| Depth of zone to be treated | 2000 feet |
| Formation permeability | .050 darcys |
| Formation porosity | 0.15 |
| Formation Fluid Viscosity | 1 cp |
| Fracture Type Desired | horizontal |
| | |
| 1. Frac. Fluid - Lease Oil | |
| Gravity | 35 ° API |
| Viscosity | 500 cp |
| Propping agent - sand | |
| Concentration | 1.5 lbm/gal |
| Pumping Time | 60 min. |
| Pack casing to allow single point horizontal entry | |
| Casing Size | 5½ in. |
| | |
| 2. Assume that a fluid loss test gives the curve of Figure 4.3 (area of filter = 20 cm ²). | |
| | |
| 3. From Table 4.2, $V_i = 25$ bbl/min. | |
| | |
| 4. $P_r = (2000 \text{ ft})(1 \text{ psi/ft}) = 2000$ psig. | |
| | |
| 5. Since a friction loss graph such as Figure 4.12 was not available for this fluid, P_k was assumed equal to 250 psig. | |
| | |
| 6. From Figure 4.13, fluid head = 0.420 psi/ft. | |
| $P_h = (0.420)(2000 \text{ ft}) = 840$ psig. | |

$$7. \quad P_s = P_r + P_f - P_h \quad (4.13)$$

$$P_s = 2000 + 250 - 840$$

$$P_s = 1410 \text{ psig}$$

$$8. \quad \text{HHP} = 0.0245 P_s V_i \quad (4.14)$$

$$\text{HHP} = (0.0245)(1410)(25)$$

$$\text{HHP} = 863 \text{ horsepower.}$$

$$9. \quad P_G = (62.4)(2000)\left(\frac{1}{144}\right)\left(\frac{32.2}{32.2}\right)$$

$$P_G = 865 \text{ psig}$$

$$\Delta P = P_r - P_g$$

$$\Delta P = 2000 - 865$$

$$\Delta P = 1135 \text{ psi.}$$

$$10. \quad \text{From Figure 1, } C_I = 6 \times 10^{-3} \text{ ft}/\sqrt{\text{min.}}$$

$$11. \quad \text{From Figure 2, } C_{II} = (11 \times 10^{-3} \text{ ft}/\sqrt{\text{min}}) \left(\sqrt{\frac{3.6 \times 10^{-6}}{1 \times 10^{-5}}} \right)$$

$$= 6.6 \times 10^{-3} \text{ ft}/\sqrt{\text{min.}}$$

$$12. \quad C_{III} = 0.0164 \frac{\text{m}}{\text{a}} \quad (4.4)$$

$$C_{III} = 0.0164 \frac{2}{20}$$

$$C_{III} = 1.64 \times 10^{-3} \text{ ft}/\sqrt{\text{min.}}$$

$$\text{From Figure 4, } C_{III}^{\text{corrected}} = 1.7 \times 10^{-3} \text{ ft}/\sqrt{\text{min.}}$$

$$13. \quad C = C_{III} = 1.7 \times 10^{-3} \text{ ft}/\sqrt{\text{min.}}$$

$$14. \quad V = V_i t$$

$$V = (25 \text{ bbl}/\text{min.})(60 \text{ min})(42 \text{ gal}/\text{bbl}).$$

$$V = 63,000 \text{ gal.}$$

$$15. \quad \text{Guess } W = 0.15 \text{ in.}$$

$$16. \quad W' = W + \frac{V_{Sp}}{15.24 a}, \quad V_{Sp} = 2 \text{ cc (from Figure 4.3)} \quad (4.12)$$

$$W' = \frac{0.15}{12} + \frac{2}{(15.24)(20)}$$

$$W' = 0.0125 + 0.00656$$

$$W' = 0.01906 \text{ ft.}$$

$$W' = 0.228 \text{ in.}$$

$$17. \quad \text{From Figure 4.6, } A = 150,000 \text{ ft}^2.$$

$$18. \quad C_r = \sqrt{\frac{A}{\pi}} = \sqrt{\frac{150,000}{3.14}} = 218 \text{ ft.}$$

19. Not needed.

$$20. \quad V_s = (1.5 \frac{\text{lbm.}}{\text{gal.}})(63,000 \text{ gal.}) \left(\frac{\text{ft}^3}{(3.44)(62.4) \text{ lbm.}} \right) = 441 \text{ ft}^3 \quad (4.11)$$

$$C_s = V_s / WA$$

$$C_s = (441 \text{ ft}^3)(12 \text{ in/ft}) / (0.228 \text{ in})(150,000 \text{ ft}^3)$$

$$C_s = 0.154$$

From Figure 4.11, slurry visc./pure frac. fluid visc. = 2

$$\text{Slurry visc.} = (2)(500) = 1000 \text{ cp.}$$

$$Q \mu C_r = (25)(1000)(218) = 5,450,000$$

From Figure 4.10, $W = 0.285 \text{ in.}$

Second Trial

15. Guess $W = 0.20$

$$16. \quad W' = \frac{0.20}{12} + 0.00656$$

$$W' = 0.01667 + 0.00656$$

$$W' = 0.0232 \text{ ft.}$$

$$W' = 0.281 \text{ in.}$$

17. From Figure 4.6, $A = 165,000 \text{ ft}^2.$

18. $C_r = \sqrt{\frac{A}{\pi}} = \sqrt{\frac{165,000}{3.14}} = 229 \text{ ft.}$

19. Not needed.

20. $V_s = 441 \text{ ft}^3.$

$$C_s = (441)(12)/(0.281)(165,000)$$

$$C_s = 0.114$$

From Figure 4.11, slurry visc./pure frac. fluid visc. = 1.7.

$$\text{Slurry visc.} = (1.7)(500) = 850 \text{ cp.}$$

$$Q\mu C_r = (25)(850)(229) = 4.87 \times 10^6.$$

From Figure 4.10, $W' = 0.280 \text{ in.}$ (assumed satisfactory within the accuracy of graphs). (Assumed corrected width was 0.281).

21. Fluid cost from Table III; assume fluid is of average cost = 0.04 cents/gal.

$$\text{Cost} = (0.04)(63,000 \text{ gal.}) + (8636)(\$1.00/\text{hp})$$

$$\text{Cost} = 2520 + 8636$$

$$\text{Cost} = \$3383.00$$

Nomenclature

- A = total area of one face of fracture, ft^2 .
- a = area of filter medium, cm^2 .
- C = a constant which is a measure of the flow resistance of the fluid leaking off into the formation during fracture treatment, $\text{ft}/\sqrt{\text{min}}$.
- C_I = constant C for fracturing fluid viscosity and relative permeability effect, $\text{ft}/\sqrt{\text{min}}$.
- C_{II} = constant C for reservoir fluid viscosity and compressibility effect, $\text{ft}/\sqrt{\text{min}}$.
- C_{III} = constant C for fluid loss additives effect, $\text{ft}/\sqrt{\text{min}}$.
- C_F = compressibility of reservoir fluid, $1/\text{psi}$.
- C_R = radius of a horizontal fracture, ft .
- E = efficiency, the volume of fracture created expressed as a function of the volume of fluid pumped.
- E_Y = Young's modulus of formation rock, psi .
- H = height of a vertical fracture, ft .
- h = depth of formation, ft .
- HHP = hydraulic horsepower requirement, horsepower.
- K = permeability of formation to fracturing fluid, darcys.
- L = length of a vertical fracture measured from the well bore, ft .
- m = slope of experimental fluid loss line when cm^3 fluid loss is plotted versus $\sqrt{t(\text{time})}$, $\text{cc}/\sqrt{\text{min}}$.
- N_{RE} = Reynold's Number.
- ΔP = difference in pressure between the fluid at the formation face and the fluid in the formation, psi .

Nomenclature, Continued

- P_f = fluid friction loss in pipe, psi.
- P_g = formation pressure, psig.
- P_h = hydrostatic fluid head of fracturing fluid in pipe, psig.
- P_r = hydraulic pressure required to maintain fracture parting, psig.
- P_s = surface pump pressure, psig.
- Q, Q_i, V_i = constant injection rate during treatment, bbl/min, ft³/min, bbl/min.
- SpGr = specific gravity of fracturing fluid, dimensionless.
- t = total pumping time, min.
- V = volume of fracturing fluid pumped, ft³.
- V_s = volume of sand injected into fracture, ft³.
- V_{Sp} = spurt loss in fluid loss test, cm³.
- W = fracture width, ft. or in.
- W' = corrected fracture width, ft. or in.
- x = $\frac{2C\sqrt{\pi t}}{W}$.
- μ, μ_F = viscosity of fracturing fluid, cp.
- μ_R = viscosity of reservoir fluid, cp.
- ϕ = porosity of formation.
- ρ = density of water, lbm./ft³.

TABLE 4.1

Estimates of Young's Moduli of Formation Rocks^{4.4*}

<u>Type of Rock</u>	<u>Probable Value of E (psi)</u>
Porous, Unconsolidated to Lightly Consolidated (Friable) Sands	0.5 to 1.5×10^6
Medium-Hardness Sandstone	2 to 4×10^6
Hard, Dense Sandstone	5 to 7.5×10^6
Limestone and Dolomite	8 to 13×10^6

TABLE 4.2

Injection Rates (Recommended) For Various Tubing Sizes^{4.6}

<u>Tubing Size (in.) (Nominal Diam.)</u>	<u>Injection Rate (bbl./min.)</u>
$2\frac{1}{2}$	10
3	15
$5\frac{1}{2}$	25

* Superscripts refer to reference from which graph or table was taken.

TABLE 4.3

Fracturing-treatment Cost Comparisons for Fluids of Various
Fracturing-fluid Coefficients Pumped at Different Injection Rates ^{4.18}

Injection Rate, Bbl/Min	C*	Treatment, Gallons	Hydraulic Horsepower, ⁺ Dollars	Fracturing Fluid, ⁺⁺ Dollars	Total, Dollars
For a 50,000 sq. ft. fracture:+++					
10	10 X 10 ⁻³	Impossible	\$	\$	\$
10	5 X 10 ⁻³	88,000	735	2,640	3,375
10	1 X 10 ⁻³	8,000	735	400	1,135
20	10 X 10 ⁻³	Impossible			
20	5 X 10 ⁻³	47,000	1,470	1,410	2,880
20	1 X 10 ⁻³	5,000	1,470	250	1,720
30	10 X 10 ⁻³	110,000	2,205	1,100	3,305
30	5 X 10 ⁻³	30,000	2,205	900	3,105
30	1 X 10 ⁻³	2,000	2,205	100	2,305

For a 100,000 sq. ft. fracture:+++

10	10 X 10 ⁻³	Impossible			
10	5 X 10 ⁻³	Impossible			
10	1 X 10 ⁻³	23,000	735	690	1,425
20	10 X 10 ⁻³	Impossible			
20	5 X 10 ⁻³	Impossible			
20	1 X 10 ⁻³	15,000	1,470	750	2,220

* Assume \$0.01 for fluid with C = 10 x 10⁻³
 \$0.03 C = 5 x 10⁻³
 \$0.05 C = 1 x 10⁻³

+ 3,000 psi surface pressure and \$1.00 per hydraulic horsepower.

++ Fracturing-fluid cost.

+++Average width of 0.1 in.

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