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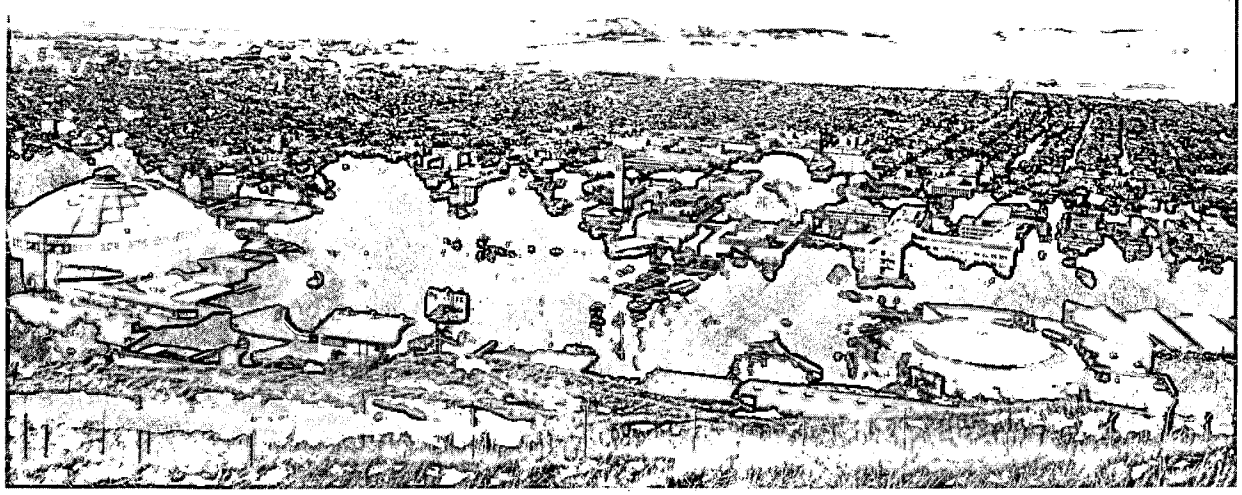

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Feasibility Analysis and Development of a Foam-Protected Underground Natural Gas Storage Facility

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ABSTRACT

Underground storage of natural gas has been practiced for over 40 years as a cost effective means of meeting peak demand. However, the volume of gas that must remain in the storage aquifer (base gas) is typically large compared to the quantity that is available for withdrawal (working gas). One way of improving the efficiency of gas storage operations is to keep the working gas closer to the withdrawal wells, and to create a thicker gas saturated region. To achieve this, the mobility of the injected gas must be controlled. We are investigating the feasibility of using foam as a mobility control agent for gas storage operations. Specific concepts for using foam to improve gas storage operations range from improved injection/withdrawal well performance to the potential for creating isolated underground storage regions. This paper describes the efforts of the first year of a three-year research program that is being sponsored by the Gas Research Institute. Laboratory studies for identifying suitable foams and for improving our knowledge of foam behavior are being carried out. In addition, a mathematical model for simulating "foam-protected" gas storage operations and for designing "foam-protected" storage operations is being developed. Preliminary economic analyses indicate a significant reduction in gas storage costs in a successfully implemented "foam-protected" aquifer gas storage operation.

INTRODUCTION

The transmission and distribution segments of the gas industry share a common interest in gas storage. To meet peak loads and to ensure dependable delivery of gas to all end-users, gas storage has become a vital link in the supply, transport, and distribution network. Of the various forms of natural gas storage technologies being employed to meet different market and application needs, large-scale seasonal storage by utilities in underground formations is perhaps the most prevalent. Since the cost of meeting seasonal and peak demands has increased considerably in recent years, a significant amount of research and development has been carried out by the gas industry to improve storage technologies and methods. These have ranged from methods for increasing reservoir capacity (overpressuring and porosity enhancement) to techniques for reducing base gas requirements (mined hard-rock caverns and salt domes).

The Gas Research Institute (GRI) is currently involved in the development of concepts aimed at an enhancement of natural gas service to the consumer. To maintain the attractiveness of the gas options to industrial customers, and to reinforce the "value-in-use" of natural gas to present and potential residential as well as commercial customers, it is essential to develop efficient, economical, and safe means of reducing the "cost of service," including that of natural gas storage in underground formations.

One specific aspect of underground storage of natural gas merits further research; viz. migration of gas beyond the designated storage area during the gas injection cycle. During the formation of the initial storage volume in an underground aquifer, some of the injected gas will finger away from the main bubble, sometimes for long distances, because of the adverse mobility ratio between water and gas. This migrated gas is often difficult to recover, thus, leading to a reduced percentage of working gas. It is, therefore, important to devise effective means of controlling such migration in underground natural

gas storage facilities. For storage in underground aquifers, gas must displace water from the porous medium. Unfortunately, gas does not invade a water-saturated zone in a uniform piston-like fashion. Rather, the gas front breaks up and "fingers" through the water, leading to a very inefficient displacement mechanism. Also, because of its low density, the gas tends to rise to the top of the system where it migrates as a thin layer (gravity override). More importantly, high mobility of gas compared to that of water, results in formation of thin gas zones far from the main bubble. During gas withdrawal, these far-removed zones can be trapped as off-site and isolated gas which is practically unrecoverable.

Extensive experience of oil recovery practice points out the fact that stable, efficient displacement requires the mobility of the drive fluid to be equal to, or only slightly less than, that of the displaced fluid. In the case of water displacing a more viscous oil, aqueous polymer solutions are used for "mobility control". Because of its exceptional flow properties and its cost, foam is currently undergoing extensive field testing in oil recovery processes, notably steam flooding. A considerable body of information is also growing to aid in detailed understanding of foam flow behavior in porous media.

The economic and market factors which influenced the development of gas storage technologies and methods in the past have changed. The cost of base gas has now become a major cost element, making a high turn-over ratio critically vital. Thus, there exists a need to critically examine relevant research programs in oil recovery processes to assess the feasibility of employing similar technologies and/or techniques to reduce migration of natural gas in underground storage facilities.

One possible solution would be to use a natural gas/water foam as a mobility control agent. Because the foam would contain over 95 percent by volume of natural gas, it would provide a compatible and an easily applied source of mobility control. Specifically, a number of analytic and technical questions must be answered before foam barriers can be applied successfully in the field. These questions include, but are not necessarily limited to, the following:

- What is the applicable "state-of-the-art" as far as the use of foam as a mobility control agent is concerned?

- What are the desirable properties of foam stabilizing chemicals? What are the selection criteria governing the choice of a given foam stabilizer?

- How is the foam generated in the porous media? How does it actually flow? How can this behavior be simulated mathematically?

- Is the foam barrier concept technically feasible? If yes, how can it be verified or validated experimentally?

- What are the preliminary economics of foam-protected natural gas storage reservoirs?

- What criteria should be used to select a field test site?

- What are the initial market penetration opportunities for foam-protected natural gas storage reservoirs?

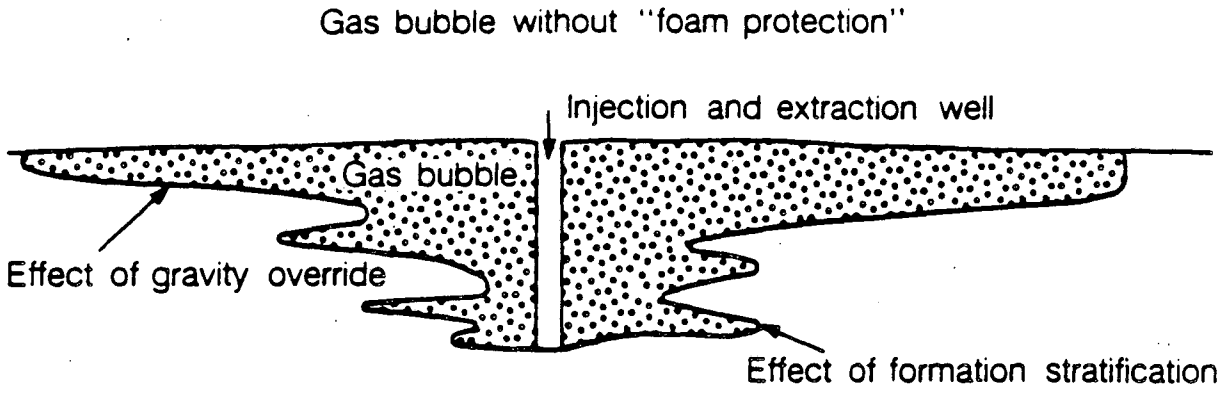
In order to answer these and other pertinent questions, GRI is sponsoring a comprehensive research program at Lawrence Berkeley Laboratory (LBL) to assess technical feasibility and economics of using foam barriers for controlling the migration of natural gas in underground storage facilities; to provide detailed understanding of foam flow behavior in porous media; to develop alternative foams that have long-term stability; and to verify their performance in actual applications via selected field tests in United States.

FOAM PROTECTED STORAGE CONCEPTS

The ability of foam to control the mobility of the injected gas and to block undesired gas flow can be used to improve the efficiency of underground gas storage operations with several different concepts. The earliest documentation of the concept of using foam for this purpose was presented by Bernard (1967), who proposed to take advantage of the ability of foam to block undesired gas flow and to create better closure of the natural structure of the storage aquifer. Later, Bernard and Holm (1970) proposed to take advantage of the ability of foam to block gas flow to seal natural leaks in the storage facility. In the current study, we are investigating the potential for exploiting the ability of foam to achieve mobility control and its ability to block undesired gas flow to improve the efficiency of gas storage operations. The general concepts currently being pursued were outlined by Radke, et al., 1983, and are reviewed briefly below..

The first of these concepts, which is illustrated in Figure 1, relies on the ability of foam to achieve mobility control during the injection phase of the storage operation. By injecting a slug of surfactant solution before the gas is injected, a foam blanket is formed between the initially water-filled aquifer and the gas behind it. The foam blanket acts to stabilize the interface between the gas and water during the injection phase, thereby improving the displacement efficiency, minimizing gravity override, and counteracting the effects of geologic heterogeneity. This concept can be used to achieve a deeper, more compact gas bubble around the injection well, which results in improved gas recovery during the withdrawal phase.

A more elaborate version of this concept (illustrated in Figure 2), which provides even better "protection" of the stored gas, could be achieved by creating a permanently emplaced "foam barrier" around the injection well. The barrier would be created by injecting a mixture of gas and surfactant solution into the aquifer until a sufficient volume of foam is emplaced. The barrier is then driven away from the injection well by the working gas. This procedure creates a cylindrical, water-free storage volume that can be used for repeated injection and withdrawal cycles. If sufficiently stable foams are developed, creation of the barrier need only be done once. Otherwise, periodic regeneration of the barrier may be required.



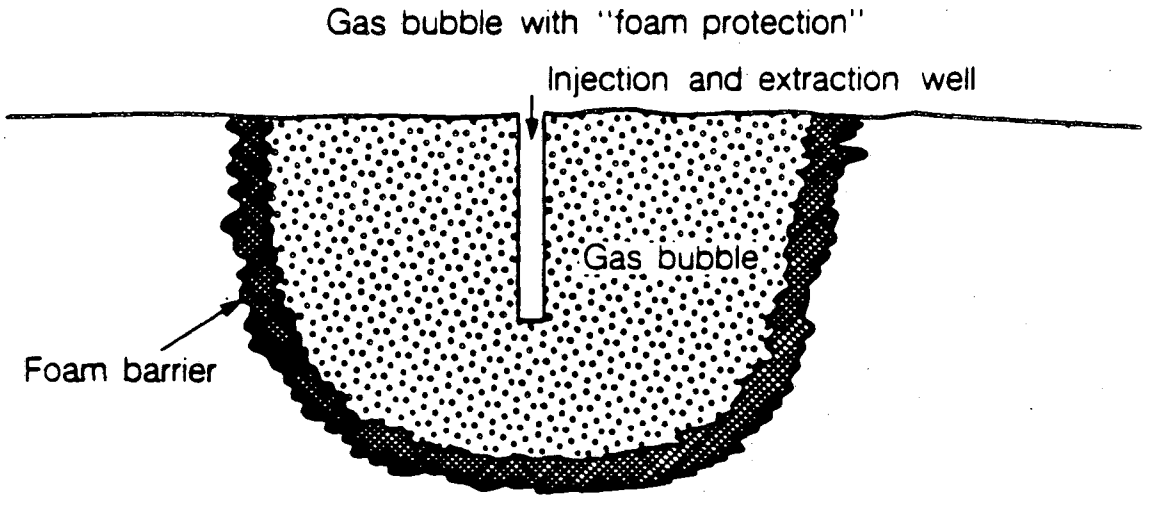


Figure 1. Schematic of gas injection with and without mobility control.

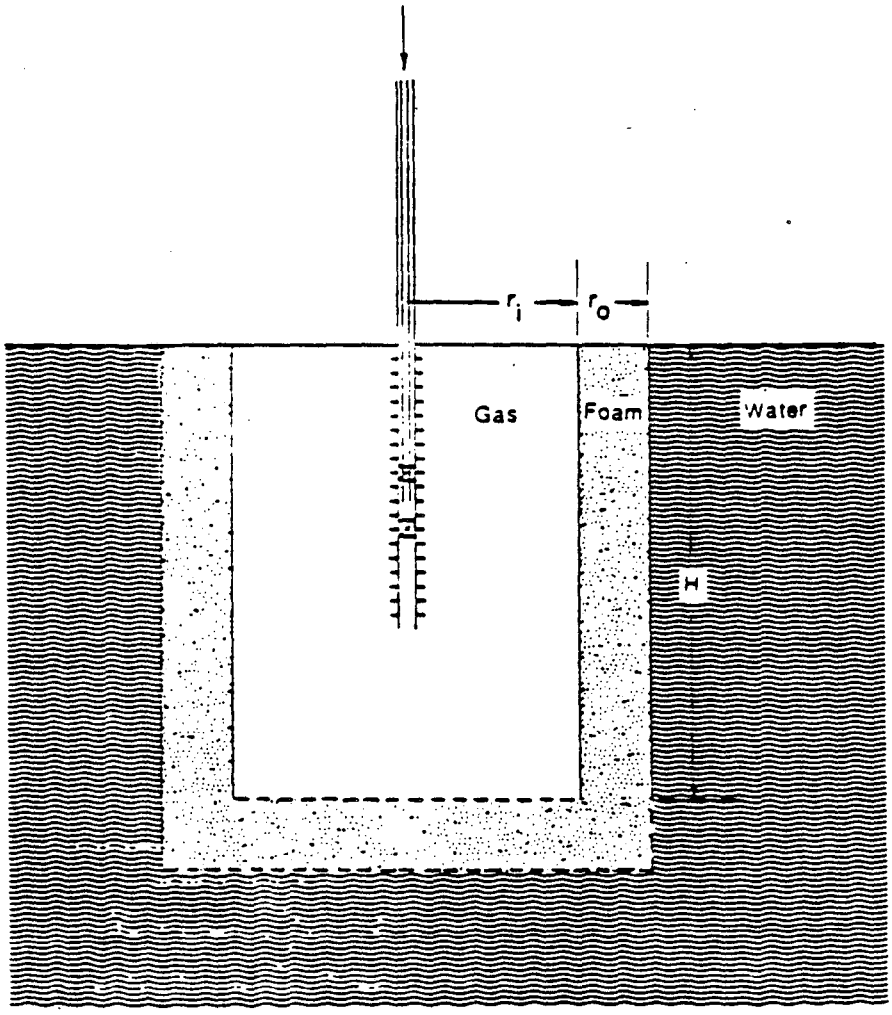


Figure 2. Single well "foam protected" storage facility.

A larger storage volume can be created by the "skirt well" concept illustrated in Figure 3. In this concept, foam is injected through a ring of wells to form a continuous blanket of foam that surrounds the designated storage volume. This technique would allow for creating storage facilities in aquifers that do not have adequate natural closure. The multi-well barrier concept can also be used to lower the "spill point" in an existing storage aquifer, thereby creating a larger storage volume and preventing leakage of gas beyond the designated storage volume. This concept is illustrated in Figure 4.

TECHNOLOGICAL DEVELOPMENT

During an initial survey of the previous studies on the rheological properties and blocking ability of foam, several areas were identified that needed additional development prior to field-scale tests of "foam protected" aquifer gas storage (Radke et al., 1983). These include identification of aquifer-brine compatible surfactants; development of stable foams; improved understanding of foam flow and blocking phenomena; and improved techniques for mathematical simulation of foam behavior. Thus far, we have concentrated our efforts on two areas: laboratory studies and development of a mathematical simulation capability. The results of these efforts, which represent the first year of a three year research program, are presented below.

LABORATORY STUDIES OF FOAM PROPERTIES

Foam has been demonstrated to retard or block the flow of gas in porous media. Most of this previous work in this area has been done to evaluate using foam as a driving fluid for enhanced oil recovery. The use of foam to displace oil from porous media was motivated by observations that it has greater viscosity than either its gas or liquid phase. Fried (1961) found that foam drive could displace oil from sandpacks that remained after alternating gas and water drives. In some tests, when foam was injected at constant pressure, the flow rate decreased and flow eventually was blocked.

The ability of foam to completely block gas flow in porous media was demonstrated by Bernard and Holm (1964) who also conducted additional experiments to measure the duration of the period that permeability was reduced. Foam blocks lasted up to 30 days in 30-ft sandpacks. Reduced permeability lasted longer in longer sandpacks and in less-permeable sandpacks.

Bernard and Holm (1970) conducted a study to evaluate foam for sealing leaks in gas storage reservoirs. Surfactant solution was injected into a partially saturated sandstone slab through which gas was flowing, simulating efforts to seal a leak. In one trial, the permeability to gas was reduced from 294 to 15 mD and maintained at that level for over 1000 hr, suggesting that foam blockage or at least reduced permeability can be maintained for months in low-permeability rocks.

Albrecht and Marsden (1970) formed foam by injecting gas at constant pressure into a porous medium that was initially saturated with a foamer solution. When foam emerged from the porous medium at apparent steady state, they reduced the gas injection pressure and observed that foam flow stopped. With sandpacks (beach sands,

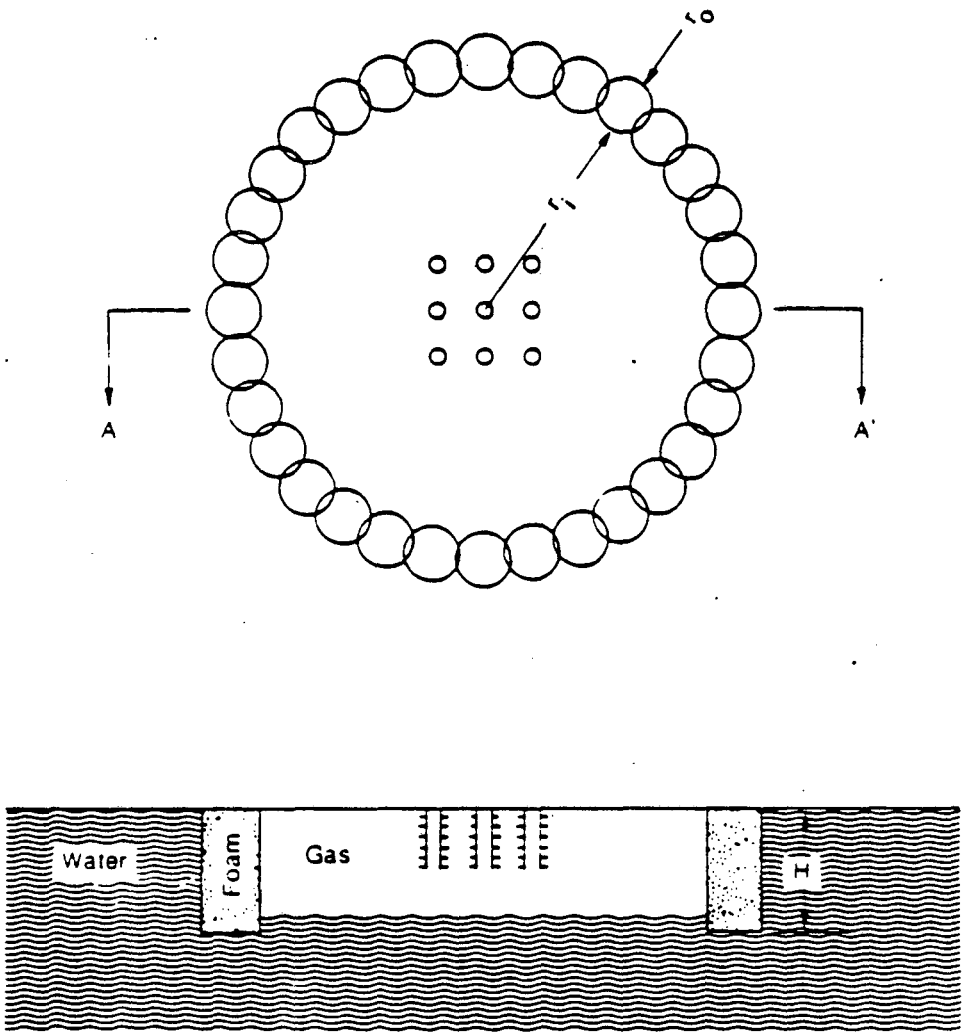


Figure 3. Skirt well "foam protected" storage facility.

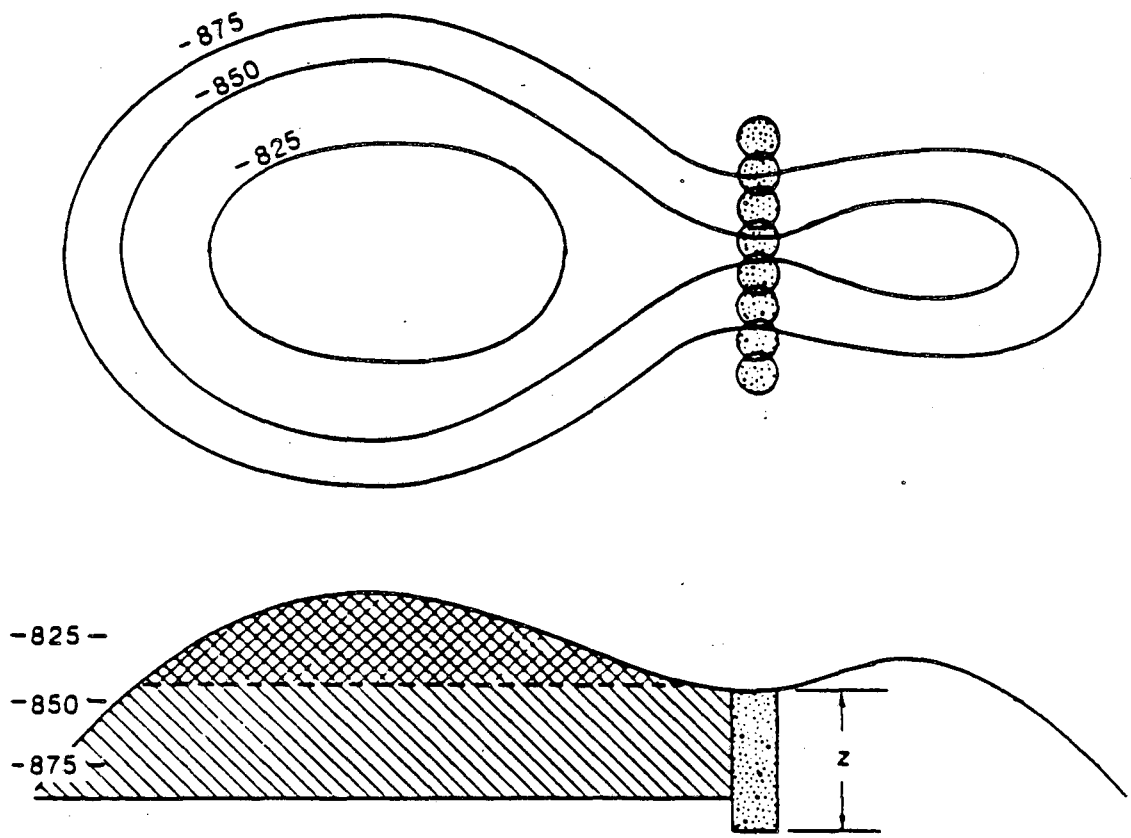


Figure 4. Spill-point lowering with a "foam-barrier".

apparently with a narrow particle size range), only a small decrease in injection pressure was needed to block flow, but in sandstones (presumably with a wider range of pore sizes) a larger decrease in injection pressure was needed to stop the flow of foam. No measurements were reported of how long the blocked condition lasted. The proposed mechanism of blocking is that when gas pressure decreases, the bubbles expand in the pores until the pressure gradient needed to push them through the pore throats exceeds the available gradient.

The above-mentioned studies, amongst others, lead to the conclusion that foam has a good potential for use in aquifer gas storage operations. However, prior to field scale testing, additional investigations are required. During the first year of this research effort, we have concentrated on screening surfactants for aquifer brine compatibility, stabilizing foams with various chemical additives, measuring foam flow behavior, and studying foam blocking. The results of these studies are summarized below.

Surfactant Screening

Brines in gas storage reservoirs commonly have high salinity and hardness. A synthetic brine was used in this work, containing 5410 mg/L Ca; 1260 mg/L Mg; 66700 mg/L total dissolved solids; and 18750 mg/L as $CaCO_3$ hardness. Four classes of oil field surfactants were screened for brine compatibility: Shell Enordet AOS (alpha olefin sulfonate), AE (alcohol ethoxylate), AES (alcohol ethoxysulfate) and Chevron Chaser (alkylsulfonate) products. Of these, the AOS and Chaser products were eliminated because they formed precipitates with the Ca ions. The AES surfactants were selected for further tests because, being anionic, they were expected to be less susceptible to sorption on reservoir rocks than the nonionic AE surfactants.

Measurement and Enhancement of Foam Stability

Previous work has shown foam stability to be a key element in achieving blocking of gas flow, and foam stability would also be necessary to maintain blocked conditions for a period of months during a gas storage cycle. Foam is a collection of gas bubbles separated by liquid lamellae. Foams decay by liquid drainage, which thins the lamellae; by spontaneous rupture of thinned lamellae; and by pressure-driven diffusion of gas from small bubbles to larger ones.

Foam stability is enhanced by stabilizing the lamellae against spontaneous rupture. Lamellae rupture spontaneously when thin spots, which are ever present due to thermal motion of the molecules, deepen and become holes in the lamella instead of being restored. Lamellae are stabilized against spontaneous rupture by forming a dense, coherent layer of surfactant molecules at the gas-liquid interace. Ionic surfactants align themselves like matchsticks at the gas-liquid interface, with their charged ends penetrating the water. These charged ends to repel each other, preventing the formation of a dense, stable surfactant layer. A denser packing of molecules at the interface is possible if a nonionic surfactant is added. The molecules of the nonionic surfactant are hypothesized to pack between the ionic molecules, thus allowing a denser and more stable surfactant layer to form (Figure 5). The surfactant layers at opposite sides of the

lamella are of like charge, so they repel each other, thus preventing the collapse of thin spots.

Nonionic surfactants used for this purpose have included long chain alcohols (Schick and Fowkes 1957, Sharma et al 1984). We evaluated several series of foamer solutions containing various AES surfactants (1% by weight in synthetic brine) and straight chain alcohols (weight concentrations ranging from 0 to 0.8%). These commercially available materials are not single compounds, but contain a range of carbon chain lengths, e.g., C_{12} to C_{15}. The carbon chain lengths of the AES molecules and the alcohols were matched as closely as possible.

Foam stability was evaluated using a variant of the Ross-Miles pour test, in which a volume of liquid is dropped from a pipette through a specified distance into a graduated cylinder. The volume of foam formed is measured initially and at intervals to determine both the foam-forming ability of the solution and the stability of the bulk foam formed in the test. This test does not duplicate the survival of foam in a porous medium, but does discriminate among foamer solutions to select those that form stable lamellae (liquid films).

Results of a typical series of tests are shown in Figure 6. Here the surfactant was AES 1213-6.5S i.e., $CH_3(CH_2)_{11-12}-(O-CH_2CH_2)_{6.5\ ave.}-OSO_3^-\ Na^+$), and the alcohol was Neodol 25 (i.e., $CH_3(CH_2)_{(11-14)}OH$). As shown in Figure 6, without addition of the alcohol, the foam collapsed rapidly, but addition of Neodol 25 up to 0.2 % increased the stability of the foam markedly. Addition of Neodol 25 beyond this level mainly increased the viscosity of the solution and thereby reduced the volume of foam initially formed in the test. Similar results were obtained with other AES surfactants.

Rheological properties of foam in porous media.

Rheological properties of foam in porous media are needed to design the emplacement of a foam barrier. The apparent viscosity of foam flowing in a sandpack was measured using the apparatus shown in Figure 7. For this experiment, a low-stability foam (1% Triton X-100 in distilled water) was used, because this reduced the flow history effects and permitted repetition of measurements without excessive waiting for steady-state conditions. The sandpack was Ottawa flint shot 3.0 sand, with a permeability of 92.6 darcy. Gas was injected at constant pressure and liquid at constant flow rate. The flow rates of gas and liquid were measured by timing and weighing the flow of foam existing the sandpack into a pre-weighed graduated cylinder. Results of this experiment are shown in Figures 8 and 9. The results in Figure 8 are counterintuitive. Ordinarily, relative permeability relationships require that at a constant injection pressure, when the flow of one phase is increased, the flow of the other decreases. In the presence of foam, however, as the liquid flow rate was increased, the gas flow rate also increased. The ratio of gas to liquid flow rate was almost completely determined by the gas injection pressure.

The volumetric flow rate of gas varied through the length of the sandpack as the pressure decreased from injection to exit. The sum of the volumetric flow rates of gas and liquid is defined as the volumetric flow rate of foam (also varying through the length

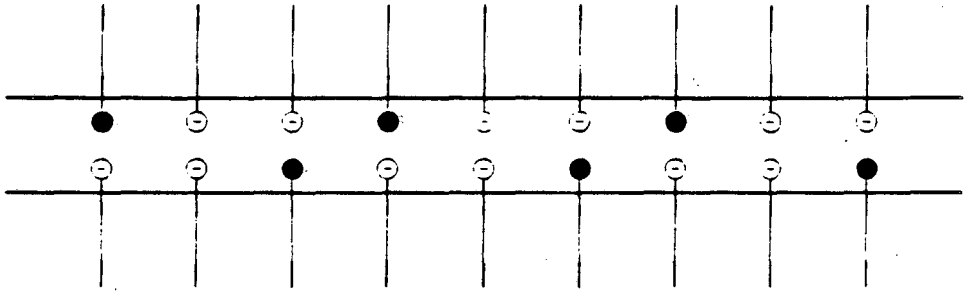


Figure 5. Anionic and nonionic surfactant molecules aligned at opposite gas-liquid interfaces of a lamella.

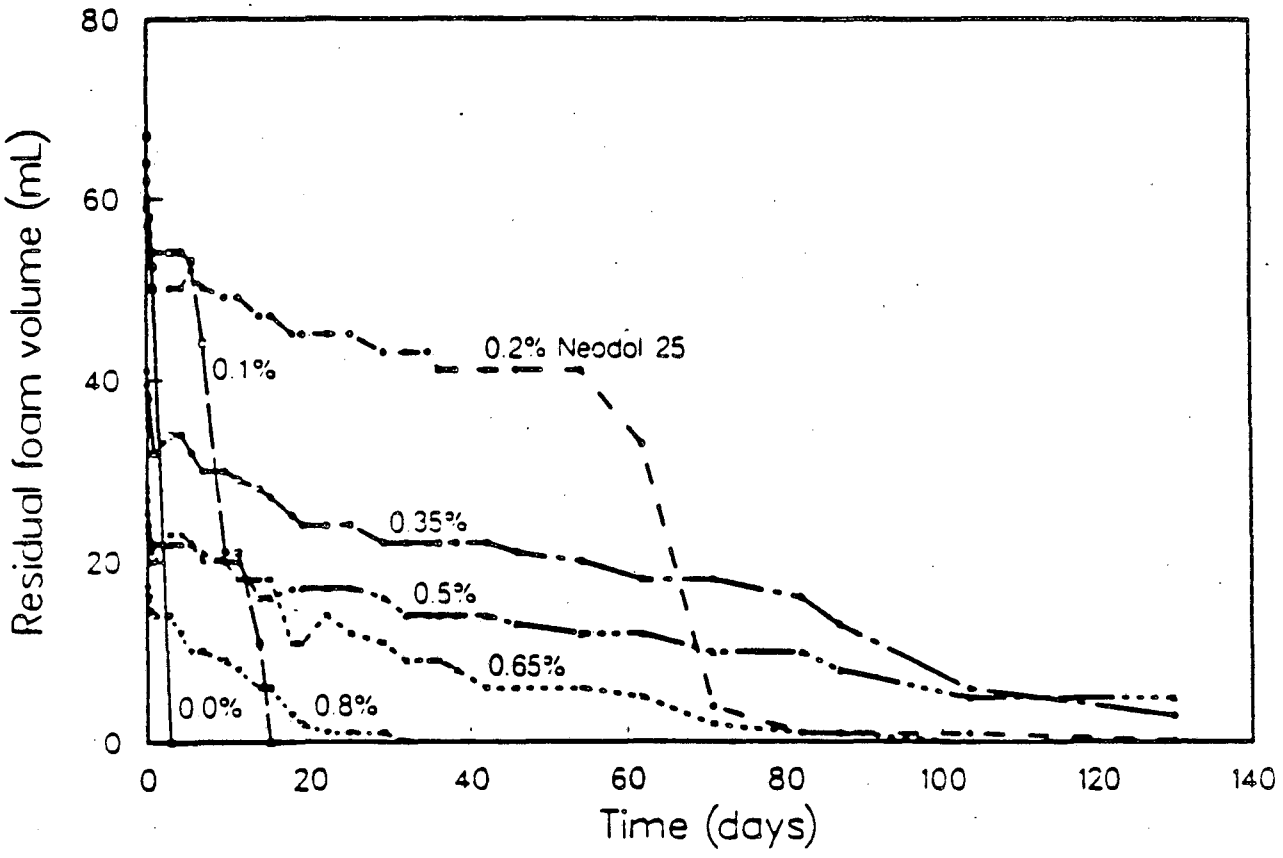


Figure 6. Static foam longevity measured in drop tests, 1% Shell Enordet AES 1213-6.5S in synthetic Mt. Simon brine, with varying amounts of Neodol 25.

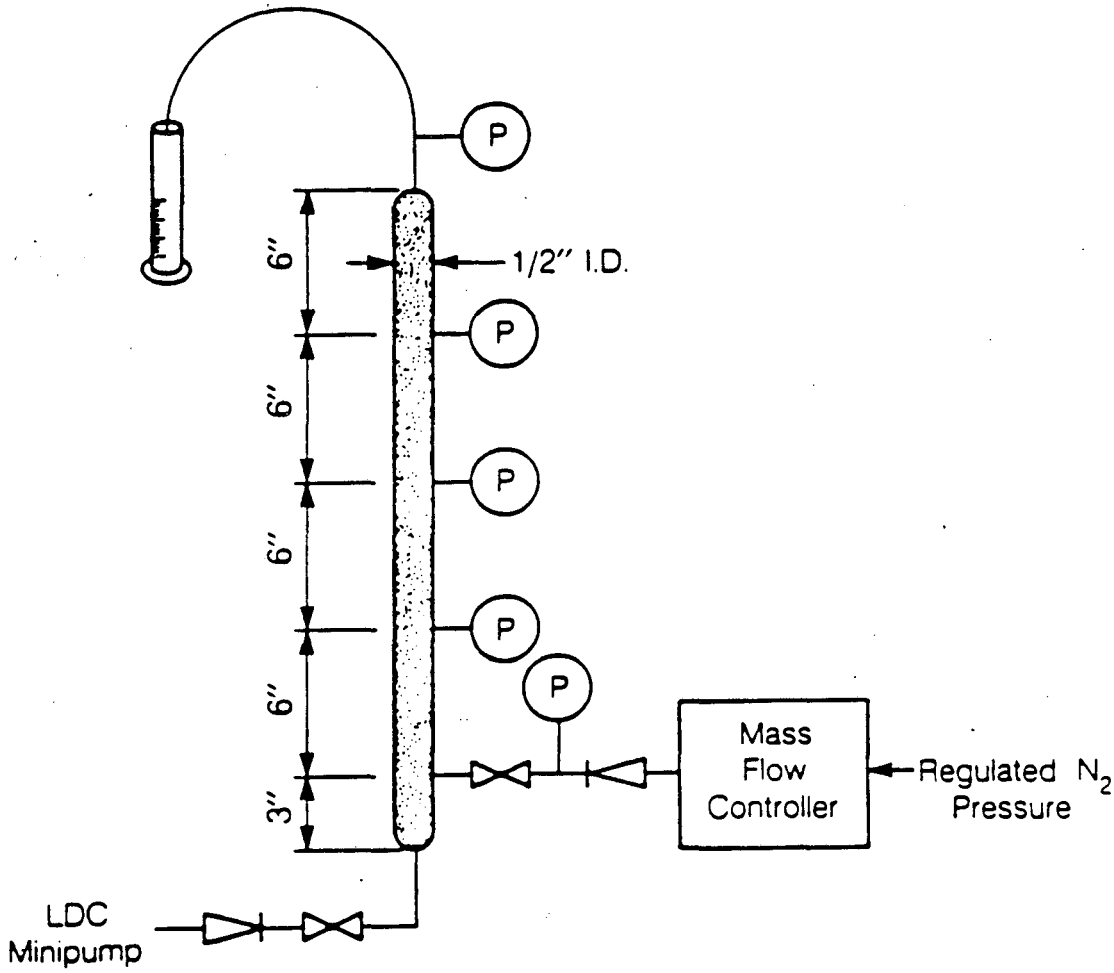


Figure 7. Apparatus for foam rheology study in sandpacks, schematic.

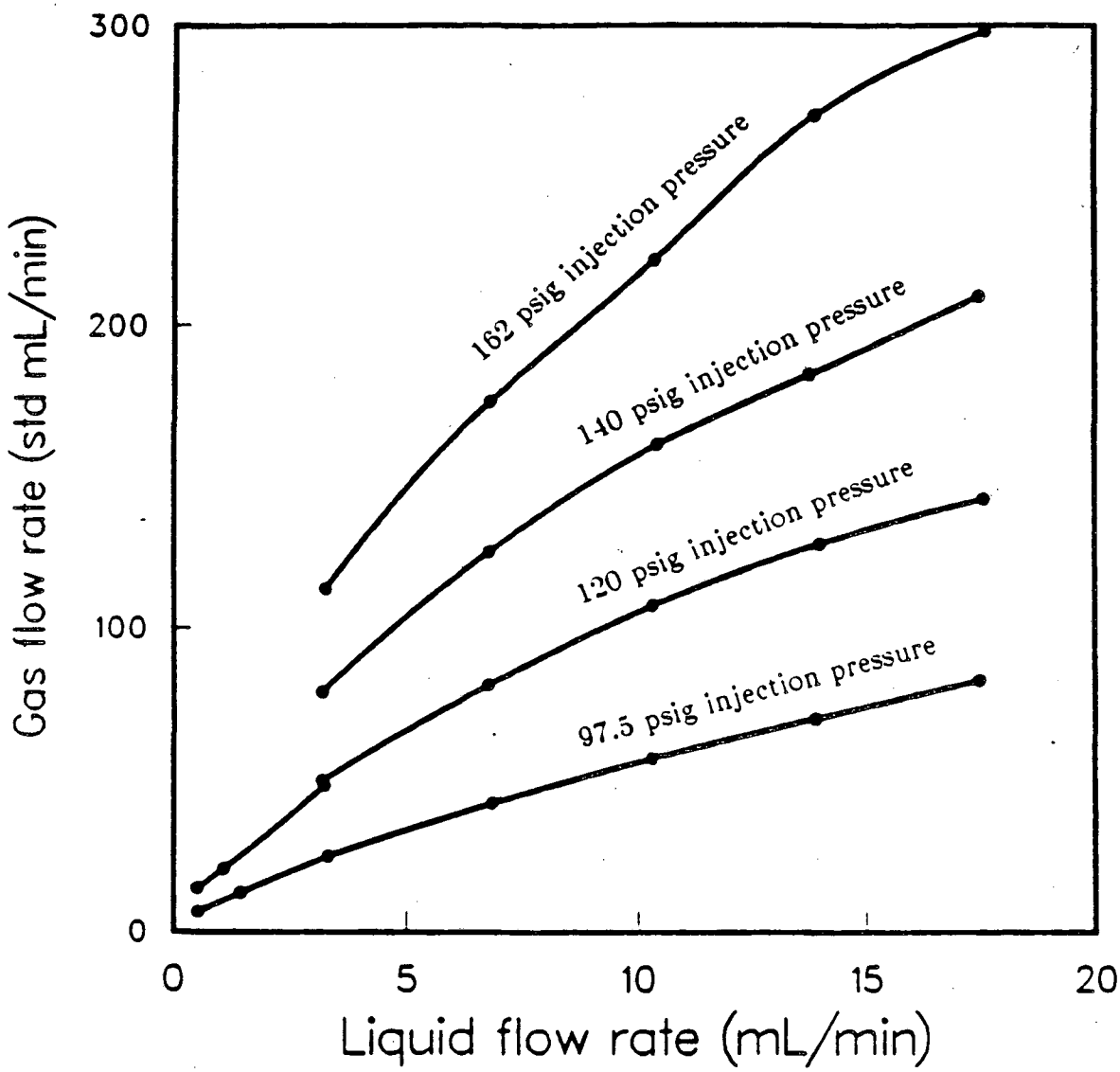


Figure 8. Foam rheology in sandpack. Plot of gas and liquid flow rates, gas injected at controlled pressure and liquid at controlled flow rate.

of the sandpack), and these data were used with the measured pressures and permeability to calculate the apparent viscosity of foam. The calculated apparent viscosity varied with the foam flow rate as shown in Figure 9. This non-Newtonian flow behavior has been observed for foam both in porous media (Treinen 1985) and in bulk foams (Fried 1961 and many since; see review by Persoff et al 1987). Description of foam flow in terms of apparent viscosity is a convenience for macroscopic modeling of foam flow in porous media and does not imply that foam flows as foam through pores. Rather, liquid is believed to flow through smaller channels while gas bubbles separated by liquid lamellae flow through larger pores. No continuous gas phase is believed to exist. The gas bubbles and liquid continually recombine to form the observed foam.

Blockage of Gas Flow by Foam

Laboratory demonstrations of gas flow blocking by foam in sandpacks were conducted to obtain greater understanding of the blocking mechanism and to measure the durability of blocked conditions. For these experiments, a stable foamer solution consisting of 1.0% AES 1213-6.5S and 0.2% Neodol 25 in brine was used. The apparatus was similar to that shown in Figure 7, but with only one pressure gauge at the inlet. Foam was formed by injecting gas at constant pressure and liquid at constant flow rate. After steady state conditions were reached, the gas flow was blocked by stopping the liquid flow and rapidly reducing the gas injection pressure from the "injection" pressure to the "holding" pressure. When this was done, flow of foam and gas through the sandpack stopped. Complete blocking of gas flow was obtained in all experiments in which the absolute holding pressure was less than 74% of the absolute injection pressure. An explanation of this observed blocking phenomenon is that when the gas injection pressure is reduced, gas bubbles throughout the sandpack expand. Trapped bubbles expand laterally, forming new lamellae which cut off continuous gas paths, blocking the flow of gas. The duration of the blocked condition in 93 darcy sand was highly variable in these experiments, ranging from less than 1 day to 48 days. Such variability apparently results from the difficulty of reproducing the same conditions at blocking (number and location of lamellae) and the spontaneous rupture of the metastable lamellae, which is a random process.

Previous work has shown that foam blocks last longer in less permeable media, therefore, additional experiments were done using Ottawa F-75 sand, which has a permeability of 20 D. In these experiments the stability of the foam was further enhanced by addition of 0.5% guar (Galactasol 253, Henkel Corp., Houston TX). This increases the viscosity of the liquid phase, retarding thinning of the lamellae. It is also suspected that the guar strengthens the lamellae by forming a network or gel-like structure in the liquid phase. Two foam blocks have now supported a pressure gradient of 5 psi/ft with no gas flow for 50 and 70 days. A similar test in 93-D flint shot 3.0 sand lasted for 5 days, so the greater longevity of the blocked condition appears to have resulted from the lower permeability of the sand. In less-permeable media, the lamellae which block gas flow are smaller, and smaller lamellae are less vulnerable to spontaneous rupture.

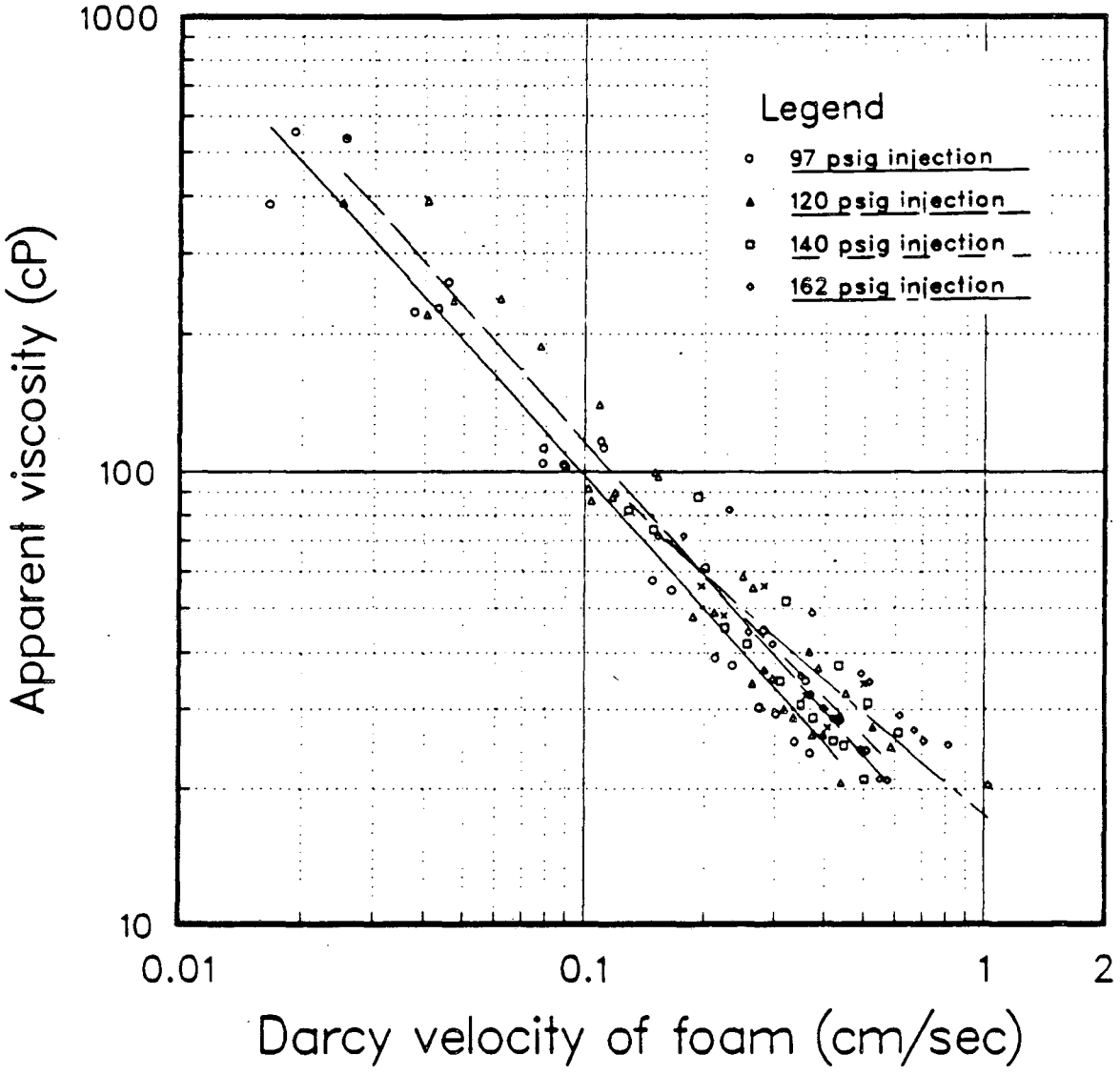


Figure 9. Foam rheology in sandpack. Plot of calculated apparent viscosity against Darcy velocity.

MATHEMATICAL MODELING

Foam is a discontinuous fluid, comprised of gas bubbles separated by thin liquid lamellae. The flow and behavior of foam in permeable media involves complex gas-liquid-solid interactions on the pore level. The quantitative aspects of these are incompletely understood at the present time, although considerable progress has been made in recent years (Hirasaki and Lawson, 1985; Falls et al., 1986a,b; Ransohoff and Radke, 1986).

While a detailed pore-level understanding of foam behavior in permeable media would be desirable, it is not necessarily a prerequisite for the formulation of quantitative models for foam flow on a continuum macroscopic scale. We propose to describe the porous flow of gas, water, and foam in a phenomenological way, using established concepts of multi-phase flow (Peaceman, 1977). In analogy to "black oil" models used in the petroleum industry (Fanchi et al., 1982) we write mass balances for the gas, water, and foam "components" as follows (symbols defined at end of paper):

$$\frac{d}{dt}\int_{V_n} M^{(\kappa)}\, dV = \int_{\Gamma_n} \underset{\sim}{F}^{(\kappa)} \cdot \underset{\sim}{n}\, d\Gamma + \int_{V_n} q^{(\kappa)}\, dV \tag{1}$$

where $\kappa = 1$ - gas, 2 - water, 3 - foam

The accumulation terms represent the mass of the components present per unit formation volume and are given by

$$M^{(\kappa)} = \phi \sum_{\beta} S_\beta\, \rho_\beta\, X_\beta^{(\kappa)} \tag{2}$$

The sum in Equation (5) extends over all phases, β, and in general the components may be present in more than one phase. However, a reasonable first approximation may be obtained by setting $X_\beta^{(\kappa)} = \delta_{\beta\kappa}$, i.e., by assuming a one-to-one correspondence between components and phases. Mass flux is given by the multi-phase extension of Darcy's law

$$\underset{\sim}{F}_\beta = -\, k\, \frac{k_{r\beta}}{\mu_\beta}\, \rho_\beta\, (\nabla P_\beta - \rho_\beta \underset{\sim}{g}) \tag{3a}$$

so that

$$\underset{\sim}{F}^{(\kappa)} = \sum_{\beta} X_\beta^{(\kappa)}\, \underset{\sim}{F}_\beta \tag{3b}$$

The equations given above are applicable to the simultaneous flow of several phases (in the thermodynamic sense; Lewis and Randall, 1961). The peculiar flow properties of foam in porous media can be represented by appropriate constitutive relationships. It has been observed experimentally that foam will flow in a porous medium only if the applied pressure gradient exceeds a certain threshold value, the magnitude of which depends on the medium and the flow history (Albrecht and Marsden, 1970). Furthermore, the resistance of foam to flow tends to diminish with increasing pressure gradient (or flow velocity; Treinen et al., 1985; Falls et al., 1986b). Following the recent work by

Hirasaki and Lawson (1985) and Falls et al. (1986b), this effect is represented by an effective viscosity that depends on pressure gradient:

$$\mu = \mu_\infty + \frac{\alpha}{[\max(0, \mid \nabla P_F \mid - P_b' \,)]^\beta + \delta} \tag{4}$$

Here μ_∞ is the asymptotic viscosity for large gradients, α and β are rheological constants, and P_b' is the threshold or blocking pressure gradient which must be exceeded for foam to start flowing. δ is a very small number introduced to avoid a singularity in effective viscosity at small gradients. We have expressed effective foam viscosity as a function of pressure gradient rather than flow velocity because this makes it possible to describe the transition from blocked to flowing condition. Our model presently does not account for hysteresis.

The pressure-density relationship for foam has been investigated by Ross (1969), Lord (1981), and Morrison and Ross (1983). Based on this work we use the real gas law to describe foam compressibility

$$PV = ZnRT \tag{5}$$

With suitable dependence of the compressibility factor Z on pressure and temperature, Equation (5) can describe a great variety of fluid behavior. However, it appears that by neglecting all contributions to foam compressibility except for that of the gas a satisfactory description can be made for a wide range of conditions.

No information is presently available on the relative permeability behavior of gas-water-foam systems. Based on wettability properties of the different phases, one might expect that the relative permeability characteristics of gas-foam flow may be very similar to those of gas-water flow, and that foam-water may behave similarly to gas-water. An important issue in multi-phase flow involving foam, which is intimately related to relative permeability as well as capillary pressure effects, is the nature of the displacement process (piston-like versus broad transition zones). If foam displacement is piston-like, as it well may be, special numerical techniques will be needed for an adequate description of the process.

Numerical Model

The governing equations given above are nonlinear and strongly coupled. For purposes of numerical solution we discretize these equations using integral finite differences in space (Narasimhan and Witherspoon, 1976) and first-order finite differences in time. For stability all flux terms are evaluated implicitly, and all discretized equations are solved simultaneously using Newton-Raphson iteration. The linear equations arising at each iteration step are solved with a sparse version of LU-decomposition (Duff, 1977).

The numerical model has been applied to aid in the design of the laboratory experiments, and for exploratory calculations of foam injection into aquifers. Of major interest are the space- and time-scales that would be involved in the emplacement of foam plumes or banks in a foam-protected gas storage scheme. An important operational constraint for foam injection is that overpressures at the injection well need to be limited to 300 - 500 psi so that formation fracturing will be avoided. As an example, Figure 10

shows predictions for the growth of a foam plume and the time-dependence of foam injection rate for foam injection at constant pressure of 1800 psi into an aquifer initially at 1500 psi. Problem parameters are given in Table 1, and Figure 11 shows the simulated pressure profile and the pattern of effective foam viscosity after 388.3 days of injection. Additional studies are underway to examine gas storage reservoir performance (injection and production rates and pressures, water coning) in the presence of hypothetical foam banks.

Analytical Model

Simplified versions of the governing flow equations were studied with a view on obtaining approximate analytical solutions in closed form. Such solutions can be useful for showing overall trends, and for verifying complex numerical simulators.

Using a somewhat simplified form for the relationship between effective viscosity and pressure gradient (setting $\mu_\infty = P_b' = \delta = 0$ in Equation (4)), we have applied an integral technique (Ozisik, 1980) to obtain approximate analytical solutions for one-dimensional linear and radial flow of foam (with no other phases present). The pressure solution for constant rate mass injection into a semi-infinite medium with 1-D linear flow is:

$$P(x,t) = P_i + \frac{1}{3}\left(\frac{Q_m\alpha}{Ak\rho_o}\right)^{\frac{1}{\beta+1}} \delta(t)\left(1 - \frac{x}{\delta(t)}\right)^3 \tag{6}$$

The function $\delta(t)$ has the meaning of a pressure disturbance penetration length and is given by

$$\delta(t) = \sqrt{\frac{12Q_m t}{A\phi\rho c}\left(\frac{AK\rho_o}{Q_m\alpha}\right)^{\frac{1}{\beta+1}}} \tag{7}$$

PRELIMINARY ECONOMIC ANALYSIS

We have attempted to carry out a preliminary analysis of the economics of foam-protected gas storage. The benefits should result from the increased recoverability of the total gas in storage, that is, an improvement in the ratio of working gas to base gas. Another possible benefit is the more efficient use of existing storage reservoirs by limiting the migration so as to avoid certain parts of a structure. To illustrate the possible economic benefits that might be realized, two examples are presented: (a) a foam-protected storage reservoir created by using a ring of "skirt wells" to develop a continuous curtain of foam (Figure 3), and (b) a storage reservoir with a lowered spill point created by injecting foam through a line of wells at an intermediate spill point (Figure 4).

Table 2 summarizes the assumptions that were adopted in developing the economics of a foam-protected storage reservoir using "skirt wells". The basic assumption was

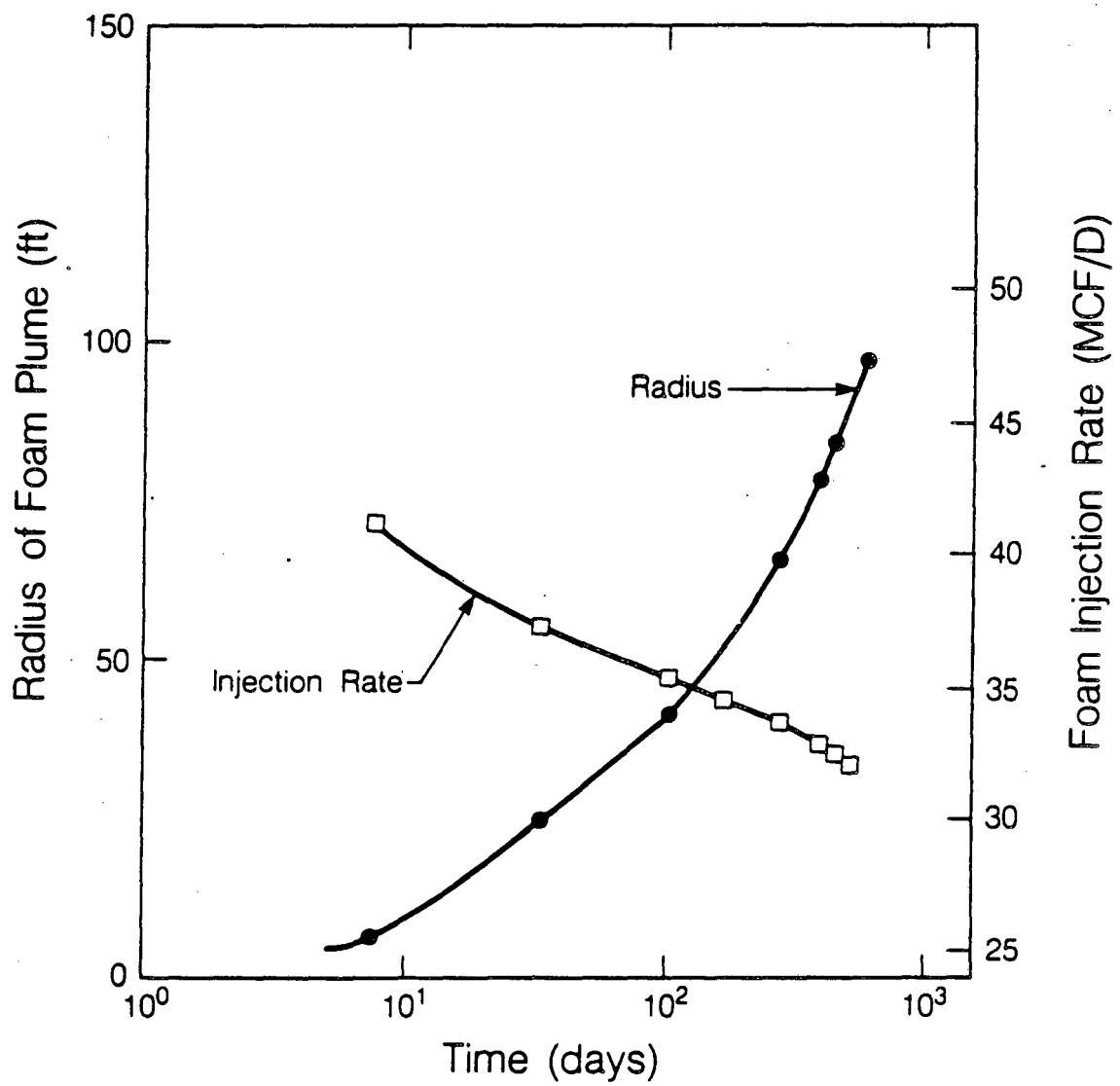


Figure 10. Foam injection rate and the radial distance to the foam "front" as a function of time.

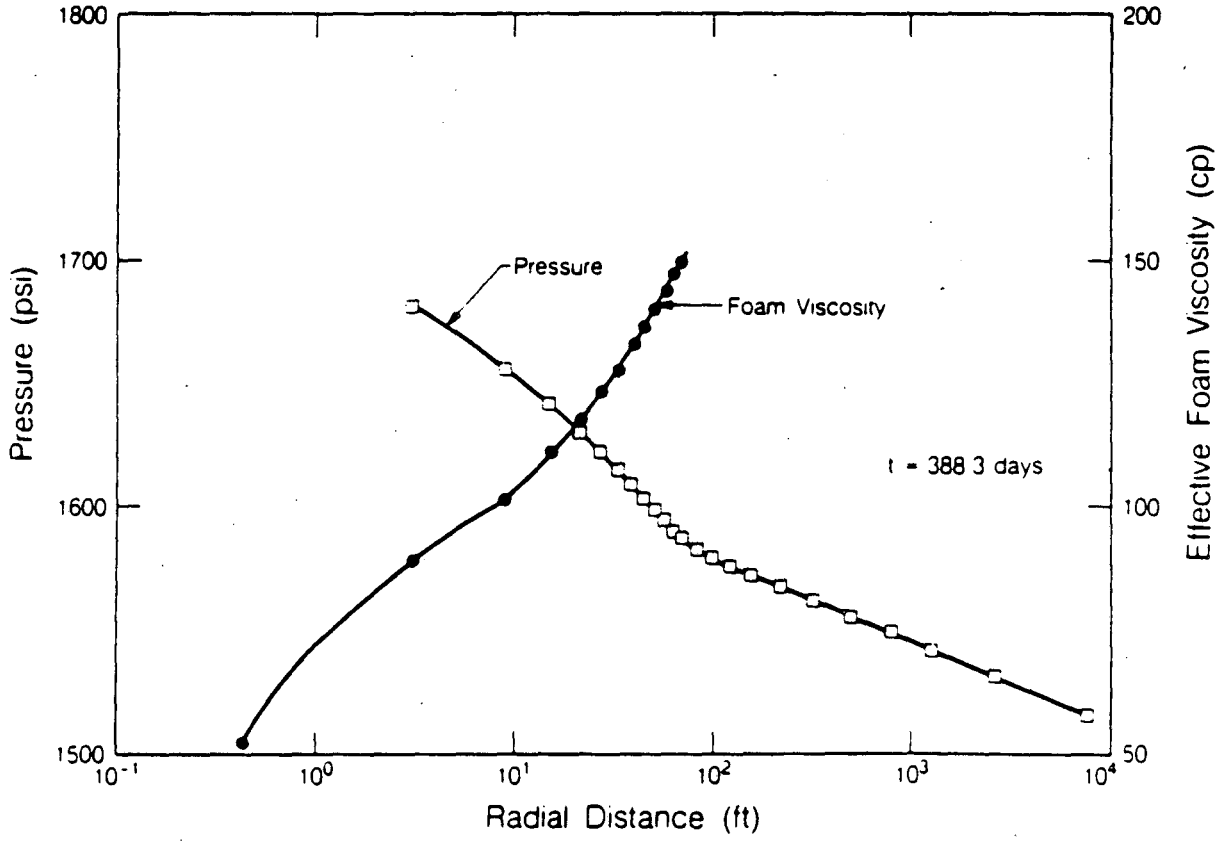


Figure 11. Formation pressure and foam viscosity as a function of distance from the foam injection well.

Table 1. Parameters for foam injection problem with 1-D radial flow.

Aquifer		
	thickness	$H = 100$ ft
	outer radius	$r = 25{,}000$ ft
	porosity	$\phi = 10\ \%$
	permeability	$k = 400$ md
	formation compressibility	$c = 5.e\text{-}6\ \text{psi}^{-1}$
	initial pressure	$P = 1{,}500$ psi
	initial temperature	$T = 86\,^{\circ}\text{F}$
Well		
	fully penetrating	
	wellbore diameter	$d = .667$ ft
	skin factor	$s = 0$
Foam		
	density at standard temperature and pressure	$\rho_F = 0.4173\ \text{lb/ft}^3$
	quality at standard temperature and pressure	$Q = 99.4\%$ gas by volume
	rheological parameters:	$P_b' = 0$ psi/ft
		$\mu_\infty = 20$ cp
		$\alpha = 110$ cp $(\text{psi/ft})^{1/3}$
		$\beta = .333$
		$\delta = 1.e\text{-}10\ (\text{psi/ft})^{1/3}$

made that the storage project should be capable of withdrawing 10 BCF working gas per season, and it was further assumed that this would require 40 BCF base gas in a conventional aquifer project. Since the costs of wells, pipelines, compressors, etc. will not change significantly, these items can be excluded, and the investment costs were therefore estimated to be $120 million.

By comparison, a foam-protected storage reservoir would be created using 50 wells to form a barrier with an internal diameter of 1500 ft, that is 200 ft wide, and has a vertical height of 300 ft. Since this would create a very large gas volume around the well field, the system should be capable of recovering a much higher fraction of the total gas in storage. We assumed that the base gas requirement could be reduced to 10 BCF, and on this basis the investment cost for 10 BCF working gas would be $72.5 million. This is almost $50 million less than the cost of the conventional approach and serves to illustrate the possibilities.

Table 3 summarizes the assumptions that were adopted in expanding the use of a conventional storage aquifer by lowering the spill point using a foam barrier as shown in Figure 12. In this case, it is desired to limit the migration of gas past the intermediate spill point at -3110 ft. As is shown in Table 3, conventional use of the structure would be limited to -3080 ft and 28.5 BCF. If one assumes 20% working gas, the seasonal withdrawal would be 5.7 BCF and would require 40 injection-withdrawal wells.

By comparison, the use of 32 wells to create a foam barrier as shown in Figure 12, could lower the spill point by 50 feet, allowing storage of an additional 43.1 BCF within the same structure. The greater thickness of the gas saturated region is assumed to improve the working gas as a percent of total gas from 20% to 30%. Due to the larger size of storage facility, and the increased rate of gas withdrawal, we estimate new costs associated with the lowered spill point facility include a 46% increase in the cost of land, injection-withdrawal wells, compressors, pipelines, etc. As a basis of comparison, we have evaluated the cost of storage per BCF of working gas, for the two cases. As shown in Table 3, lowering the spill point of the structure decreases the cost per BCF of gas from $18.5 to $10.2 million. An additional benefit from spill point lowering is the possibility of increasing the storage capacity of an existing facility, rather than having to develop new ones.

SUMMARY AND FUTURE WORK

This paper summarizes the results of the first year of a three year research program for evaluating the feasibility of using surfactant-gas foams for improving the efficiency of underground natural gas storage facilities. To date, we have concentrated on investigating the behavior of foam in the laboratory and on developing a suitable mathematical model for simulating a "foam-protected" aquifer gas storage operation. During the second year of this project we will conduct a series of laboratory experiments to study the behavior of foam in a typical aquifer sandstone, at realistic aquifer pressures. These data, along with mathematical predictions of the dynamics of the foam emplacement process, will allow us to a design a suitable demonstration project, where one or more of the "storage concepts" can be tested. During the final year of the project, after choosing a suitable field test site, we plan to carry out a field demonstration.

Table 2. Assumptions and costs for the preliminary economic comparison between a 10 BCF "foam-protected" storage facility and a conventional storage project.

I. CONVENTIONAL STORAGE		
A. Assumptions		
1. Nominal depth	3,000	ft
2. Porosity	11	%
3. Residual water saturation	20	%
4. Storage pressure	1,400	psig
5. Total gas required	50	BCF
6. Cost of gas	$3.00	per MCF
B. Costs Excluding Working Gas		
1. Base gas, 40 BCF	$120.0	M
2. Other costs*		
Total	$120.0	M
II. SKIRT WELL FOAM STORAGE		
A. Assumptions		
1. Nominal depth	3,000	ft
2. Porosity	11	%
3. Residual water saturation	20	%
4. Storage pressure	1,400	psi
5. Total gas required	20	BCF
6. Cost of gas	$3.00	per MCF
7. Skirt thickness	200	ft
8. Skirt height	300	ft
9. Skirt inner radius	1500	ft
10. Foam quality	90	% gas
11. Surfactant concentration	1	%
12. Cost surfactant	$2.00	per pound
13. Cost per well	$400	K
14. Well spacing	200	ft
B. Costs Excluding Working Gas		
1. Base gas, 10 BCF	$30.0	M
2. Foam gas, 5.3 BCF	15.9	
3. Surfactant, 3.3 M pounds	6.6	
4. Skirt wells, 50	20.0	
5. Other costs*		
Total	$72.5	M

Note: * Costs of land, injection-withdrawal wells, compressors, pipelines, etc. assumed to be approximately the same for either method.

Table 3. Data, assumptions, and costs for the preliminary economic comparison between a conventional storage project and one with a foam-blocked spill point.

CONVENTIONAL STORAGE

A. Assumptions

1. Surface elevation	620	ft above MSL
2. Depth	3080	ft below MSL
3. Porosity	11	%
4. Residual water saturation	20	%
5. Storage pressure	1600	psig
6. Total gas	28.5	BCF
7. Working gas, 20%	5.7	BCF

B. Costs Excluding Working Gas

1. Base gas, 22.8 BCF	$68.4	M
2. Other costs *	37.5	
Total cost	$105.9	
Total cost per BCF working gas	$ 18.5	M

LOWERED SPILL POINT

A. Assumptions

1. Depth	3130	
2. Porosity	11	%
3. Residual water saturation	20	%
4. Storage pressure	1600	psig
5. Total gas	71.6	BCF
6. Working gas, 30%	21.5	BCF
7. Cut off dimensions (ft) L × W × H	6400 × 200 × 25 ave.	
8. Foam quality	90	% gas
9. Surfactant concentration	1	%
10. Cost of surfactant	$2	per pound
11. Cost per well	$400	K
12. Well spacing	200	ft

B. Costs Excluding Working Gas

1. Base gas, 50.1 BCF	$150.3	M
2. Surfactant, 0.17 Million lb	0.3	
3. Cut-off wells, 32	12.8	
4. Foam gas, 0.36 BCF	1.1	
5. Other costs *	54.6	
Total cost	$219.1	M
Total cost per BCF working gas	$10.2	M

* Costs of land, injection-withdrawal wells, compressors, pipelines increased 46% to allow for increased area and increased withdrawal rate.

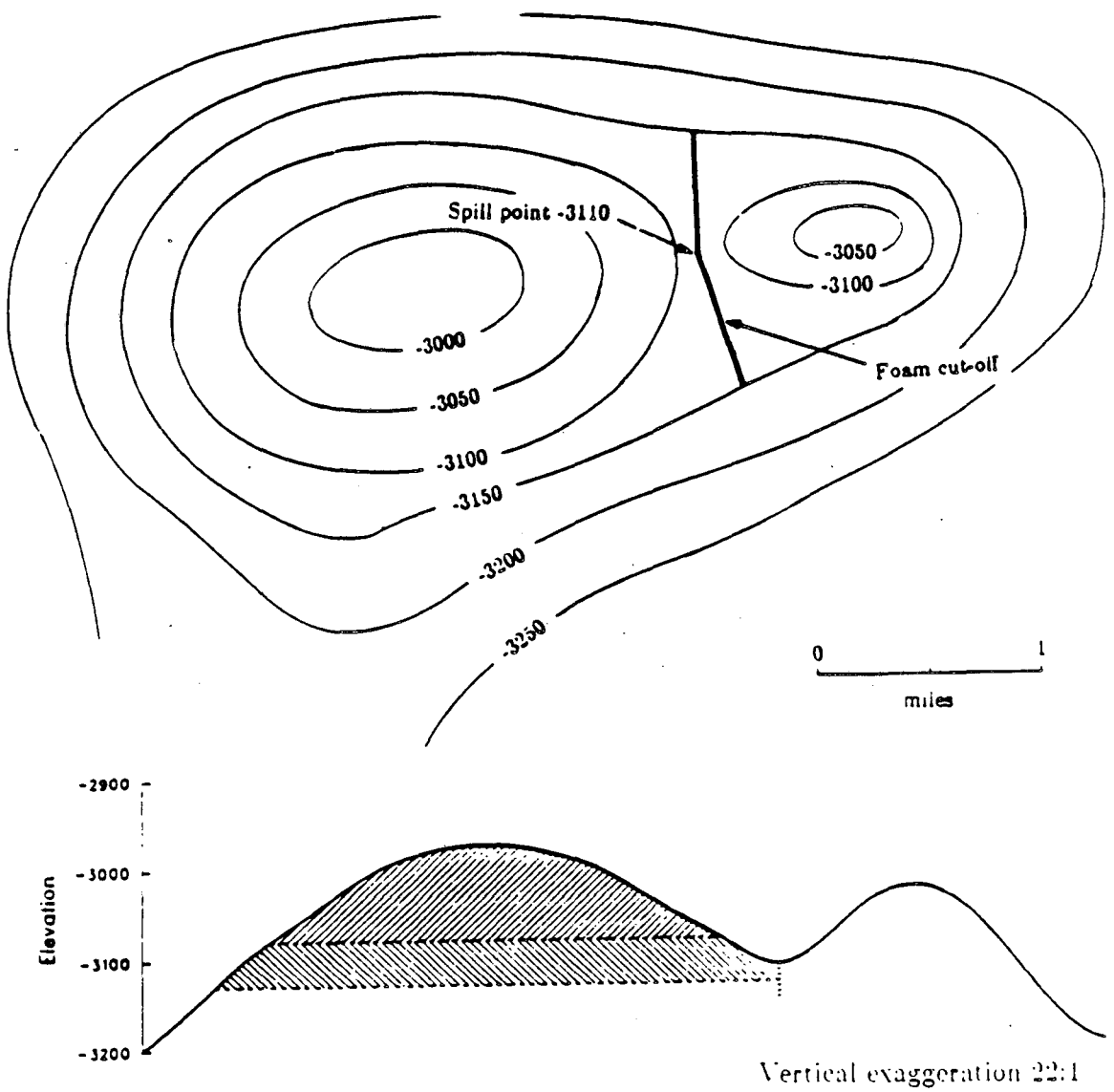


Figure 12. A schematic of the dome structure used for economic analysis of the spill-point lowering concept.

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NOMENCLATURE

A	Area (L^2)
c	Total compressibility (LT^2/M)
d	Well diameter (L)
$\underset{\sim}{F}_\beta$	Mass flux of β-phase (β - gas, water or foam)
$\underset{\sim}{g}$	Acceleration of gravity (L/T^2)
H	Formation thickness (L)
k	Absolute permeability (L^2)
$M^{(\kappa)}$	Mass of κ component (κ = gas, water or foam) present per unit formation volume (M/L^3)
n	Number of moles
$\underset{\sim}{n}$	Normal inward unit vector
$\tilde{P}$	Pressure (M/LT^2)
P_b'	Blocking pressure gradient (M/L^2T^2)
q	Source rate (M/L^3T)
Q	Foam quality (gas volume/foam volume)
Q_m	Foam mass injection rate (M/T)
q	source rate (M/L^3T)
r	Radial distance (L)
R	Universal gas constant
S	Saturation
t	Time (T)
T	Temperature ($^\circ$K)
V	Volume (L^3)
x	Length coordinate (L)
$X_\beta^{(\kappa)}$	Mass fraction of component κ in phase β
Z	Compressibility factor
α	Rheological constant of foam $\left[(M/L^2T^2)^\beta\right]$
β	Rheological exponent of foam
δ	Small number
$\delta(t)$	Pressure disturbance penetration length (L)
$\delta_{\beta\kappa}$	1 if $\beta=\kappa$; 0 if $\beta\neq\kappa$
μ	Viscosity (M/LT)
μ_∞	Foam viscosity at large pressure gradient (M/LT)
ρ	Mass density (M/L^3)

ϕ	Porosity
Γ_n	Surface of volume element n

Subscripts:

F	foam
i	Initial
m	Mass
n	For volume element n
o	Standard temperature and pressure
r	Relative
β	Phase (gas, water or foam)

Superscript:

κ	Component (1-gas, 2-water, 3-foam)

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