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Development and Testing of Underbalanced Drilling Products

Topical Report
September 1994 - September 1995

George H. Medley, Jr.
William C. Maurer
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Work Performed Under Contract No.: DE-AC21-94MC31197

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Maurer Engineering, Inc.
Houston, Texas

DISCLAIMER

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Table of Contents

Table of Contents

Table of Figures

Table of Figures (Cont'd.)

Table of Figures (Cont'd.)

List of Tables

Abstract

Underbalanced drilling is experiencing growth at a rate that rivals that of horizontal drilling in the mid-1980s. Problems remain, however, for applying underbalanced drilling in a wider range of geological settings and drilling environments. This report addresses the development and testing of two products designed to advance the application of underbalanced drilling techniques.

A user-friendly foam fluid hydraulics model (FOAM) was developed for a PC Windows environment. The program predicts pressure and flow characteristics of foam fluids used in underbalanced drilling operations. FOAM is based on the best available mathematical models, and was validated through comparison to existing models, laboratory test well measurements, and field data. This model does not handle air or mist drilling where the foam quality is above 0.97.

An incompressible drilling fluid was developed that utilizes lightweight solid additives (hollow glass spheres) to reduce the density of the mud to less than that of water. This fluid is designed for underbalanced drilling situations where compressible lightweight fluids are inadequate.

In addition to development of these new products, an analysis was performed to determine the market potential of lightweight fluids, and a forecast of underbalanced drilling in the U.S.A. over the next decade was developed. This analysis indicated that up to 12,000 wells per year (i.e., 30 percent of all wells) will be drilled underbalanced in the U.S.A. within the next ten years.

Executive Summary

INTRODUCTION

Interest in underbalanced drilling is growing worldwide at a rate not seen for a new drilling technology since the introduction of horizontal drilling in the mid-1980s. Reduced formation damage in horizontal wells has been the driving force behind the recent resurgence in underbalanced drilling. Underbalanced drilling has proven very beneficial in areas of the U.S.A. such as the Austin Chalk trend in Texas and Louisiana. The technology has recently spread very rapidly in Canada, as shown in Figure i.

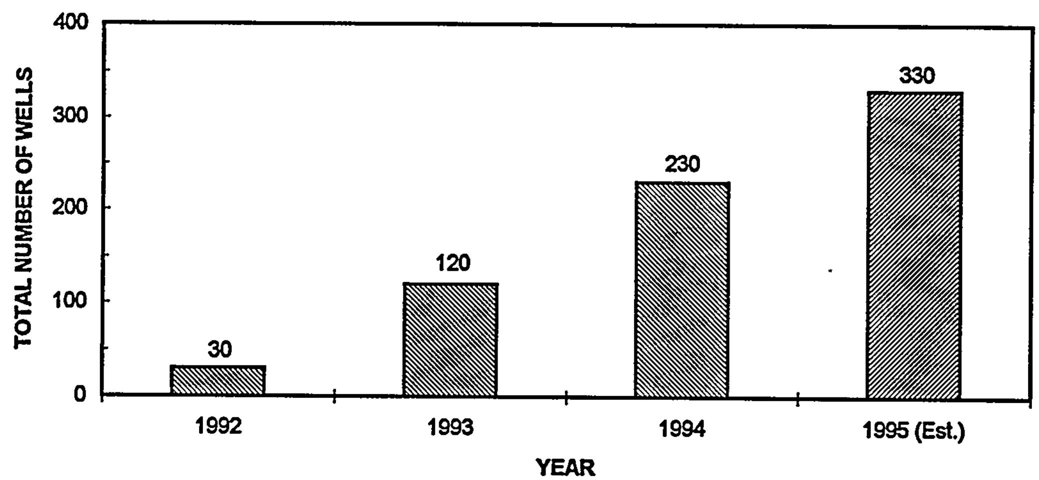

Figure i. Canadian Underbalanced Wells (Knoll, 1995)

Current underbalanced drilling operations in low pressure or depleted reservoirs can be carried out using air, mist or foam. Many operators are reluctant to drill underbalanced with foam because of the difficult hydraulics calculations required and the general lack of information and training relative to underbalanced drilling. The addition of air and gas to the drilling fluid can also cause many other problems.

The DOE sponsored Maurer Engineering Inc. (MEI) to develop a user-friendly PC foam-drilling model that can accurately predict pressure drops, cuttings lifting velocities, foam quality, and other foam drilling variables. The model will allow operators and service companies to easily and accurately predict pressures and required flow rates at the surface and down hole for foam drilling and workover operations.

A second objective of the project was to develop a lightweight drilling fluid that will allow underbalanced drilling in low-pressure reservoirs without the limitations commonly associated with existing lightweight fluids. A new lightweight solid additive was proposed and the initial investigations of its properties as a drilling-fluid additive were conducted during Phase I.

FOAM COMPUTER MODEL (Chapter 3)

A literature search was conducted to identify all available mathematical models related to the pressure and flow characteristics of foam fluids. Additional unpublished laboratory tests and mathematical models provided by Chevron and other sources were reviewed.

A PC foam drilling model was developed using the best available mathematical models. The model runs in a Windows environment and is user-friendly and accurate. Any of three rheology models can be selected, and the model can handle any combination of gases and liquids injected while drilling.

Output is generated in tabular as well as graphical form. Figure ii shows an example "tiled" output screen from the program.

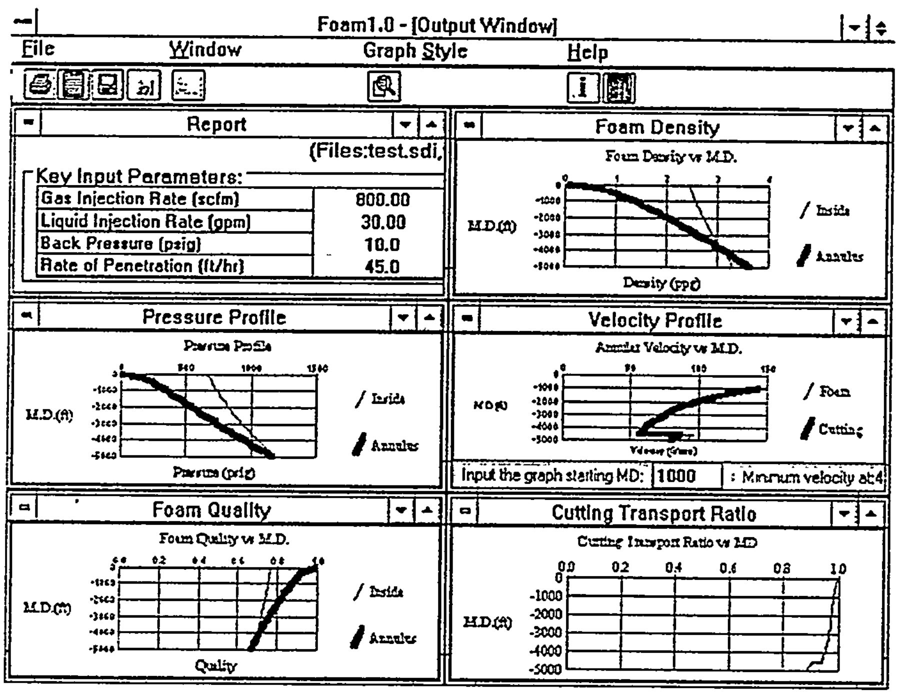

Figure ii. FOAM "Tiled" Output Window

The output from the FOAM model was validated by comparing it to other models, existing laboratory data, and actual field measurements. The FOAM model matched other known models by an average of 8.6%. It matched test well measurements (conducted previously by Chevron) by an average of 10.6%. Figure iii shows that the standpipe pressures predicted by the FOAM model matched field measurements from a well in Kansas within 20 to 40 psi (within 4%).

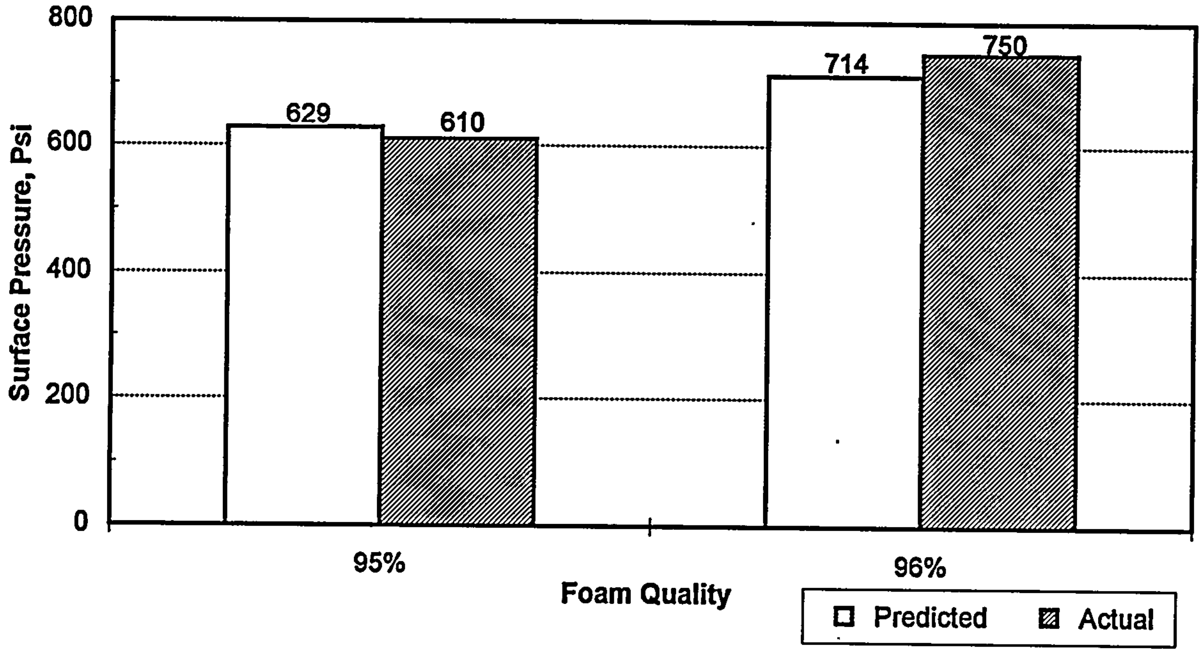

Figure iii. Comparison of FOAM to MEI Field Measurements (Injection Pressure)

LIGHTWEIGHT SOLID ADDITIVE DRILLING FLUID (Chapter 4)

Drilling underbalanced in underpressured and depleted reservoirs requires a fluid with a density lower than that of water (SG<1.0). Hollow glass spheres with a specific gravity of 0.38 were found that can be used effectively to reduce the density of drilling fluids.

Hollow glass spheres, with the capability of decreasing fluid density, have been known to the oil and gas industry for years. Their application has primarily been for lowering the density of cement slurries for combating lost circulation. However, in the early 1970s, they were used in the former Soviet Union to drill wells where lost circulation had previously made conventional drilling impossible.

A 50-percent concentration by volume of hollow glass spheres decreases the density of 8.5 ppg mud to 5.8 ppg as shown in Figure iv. This is sufficient for many field applications.

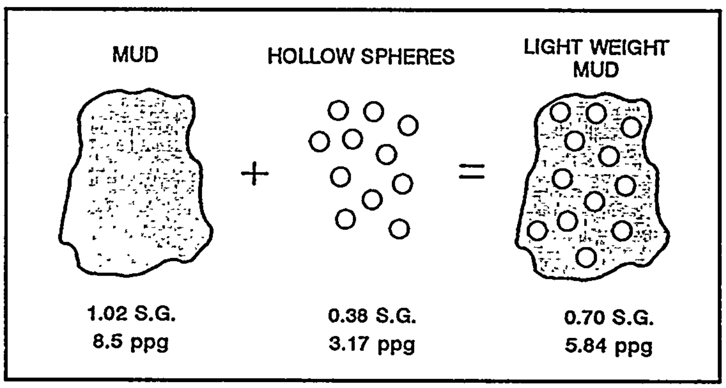

Figure iv. Lightweight Mud

For this study hollow glass spheres were used to build both water- and oil-base muds. The rheological properties of the muds were measured, and the effects of various contaminants, common to the drilling environment, were investigated.

The effects of conventional solids-control equipment on the glass spheres and on the whole mud were measured with regard to sphere damage and recovery. Conventional equipment did not damage the hollow spheres. Hydrocyclones proved to be the most effective equipment in maintaining the mud. Efficient recovery of the spheres for recycling will require dilution of the mud with water and requires effective gravity segregation.

Figure v lists the disadvantages of drilling underbalanced with the aerated fluids previously required to achieve low density.

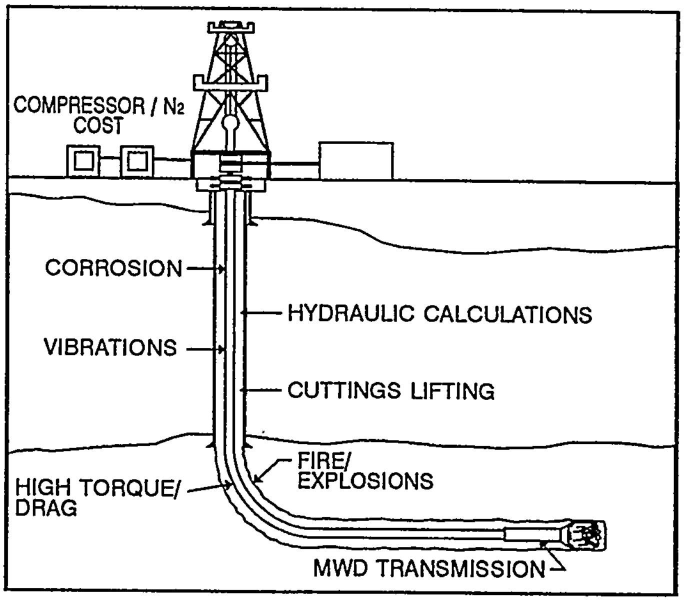

Figure v. Aerated Fluid Problems

These problems could be eliminated or greatly mitigated with a lightweight incompressible fluid. Without the introduction of oxygen, no downhole fires would be started and problems with oxygen corrosion would be eliminated. Since the fluid would no longer be compressible, hydraulics calculations would be simplified, vibrations would be damped, and MWD transmissions should not be attenuated in the fluid. Important cost savings could be achieved through the elimination of these problems.

MARKET POTENTIAL OF LIGHTWEIGHT FLUIDS (Chapter 5)

Lightweight fluid use has historically been confined to specific geographic regions where the conditions favored the use of underbalanced drilling to increase the rate of penetration. In the last few years, the emphasis in underbalanced drilling has shifted from cost reduction and increased drilling rates to reduced formation damage and improved productivity. This has expanded the potential applications of underbalanced drilling techniques.

An environment of hard rocks where conventional drilling techniques produce slow penetration rates is no longer the only application for underbalanced drilling. As reservoirs in the U.S.A. have been depleted by years of oil and gas production, problems with formation damage, lost circulation, and differential sticking while drilling have become more common and more important. Underbalanced drilling with lightweight fluids has the potential to overcome all of these problems.

The potential market for lightweight fluids was evaluated based on current industry drilling levels and expected rates of growth for underbalanced drilling specifically. Data from a broad spectrum of industry sources were considered and incorporated into this study.

The lightweight fluid market is currently demand-driven. All available equipment is being utilized in the U.S.A. The underbalanced drilling market has the potential to grow to 30 percent of all domestic drilling within the next 10 years, according to the results of an industry survey.

Figure vi shows that by the year 2005, nearly 12,000 wells/year may be drilled with lightweight fluids in the U.S.A., according to a recent industry survey.

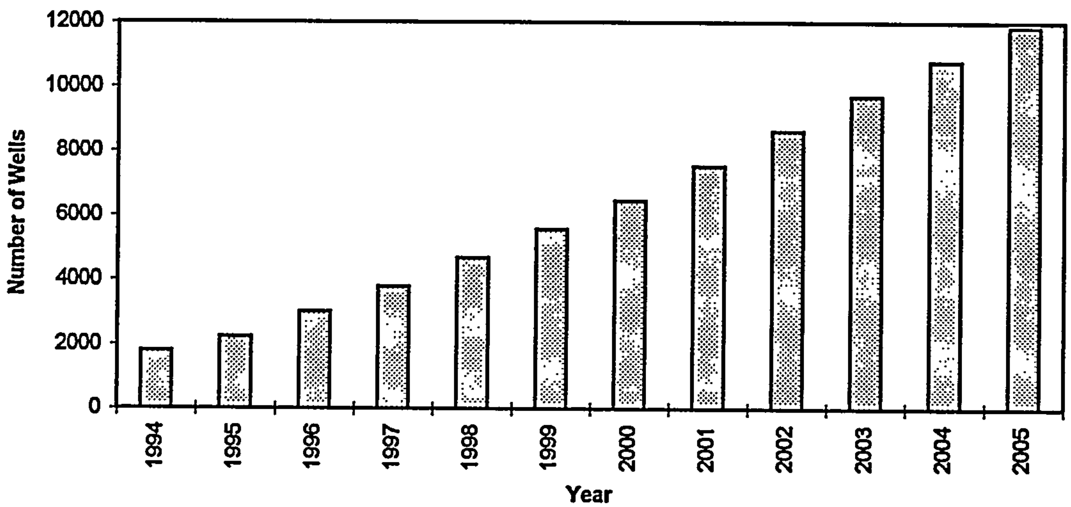

Figure vi. Projected Industry Use of Underbalanced Drilling

1. Conclusions

This study concentrated on the development and testing of a new, user-friendly, foam fluid hydraulics model for personal computers and the use of solid additives to create a new lightweight drilling fluid that will overcome the problems associated with aerated drilling fluids. Many conclusions were reached in the course of the study. The most significant are presented here.

1. A need does exist for an easy to use, personal computer model for foam drilling fluids.
2. The PC model developed in this project for calculating pressure responses and flow behavior of foam drilling fluids has been shown to be accurate by comparison with existing measurements.
3. The FOAM computer model is available for use by the oil and gas drilling industry.
4. An incompressible fluid having a density less than water would overcome many of the problems associated with aerated fluids, opening up many new areas to underbalanced drilling.
5. Lightweight incompressible drilling fluids can be constructed using commercially available hollow glass spheres. At sphere concentrations below 40% by volume, lightweight muds behave similarly to conventional drilling fluids.
6. Laboratory tests show that a hollow glass sphere drilling fluid will significantly decrease casing wear caused by drill-string rotation.
7. Conventional drilling rig solids-control equipment does not damage the hollow glass spheres.
8. The collapse pressure of hollow glass spheres (4000 psi) will allow their use in relatively deep underbalanced wells (i.e., 9,000 to 10,000 ft depth).
9. Drill solids must be removed with large-mesh shale shaker screens and hydrocyclones. Conventional oil-field centrifuges are not effective in removing drill solids or hollow glass spheres from these muds.
10. Low-cost methods of separating spheres from whole mud should be feasible using a combination of gravity segregation, conventional hydrocyclones and shale shakers.
11. The cost of hollow glass sphere muds can be significantly reduced by recovering and recycling the spheres. Hollow sphere muds should be competitive with nitrogen drilling, even without recycling the spheres.
12. Underbalanced drilling has been effective in many different types of reservoirs. The technology is not limited by depth, having been used successfully at depths ranging from 200 to 20,000 ft.
13. Both operating and service companies project large growth rate for underbalanced drilling over the next decade (e.g., up to 37 % of all wells).
14. The most significant non-technical barriers to the growth of underbalanced drilling in the United States are limited equipment availability, lack of familiarity with lightweight fluids, and a perception of high cost.

15. The largest technical barriers to growth in underbalanced drilling are handling formation influxes, the inability to use conventional MWDs with compressible lightweight fluids, and corrosion.
16. Ninety-four percent of all operators surveyed are willing to consider using a lightweight solid additive drilling fluid such as that developed on this project.
17. By the year 2005, underbalanced drilling in the United States is projected to account for 10,000 to 12,000 wells per year, depending on the growth of conventional drilling. From 2,500 to 3,600 gas wells are forecast to be drilled underbalanced per year.

2. Introduction

2.1 BACKGROUND

Oil companies first began drilling wells with air in the late 1940s. Primary motivations to use air were to increase drilling penetration rates through hard formations and to overcome severe lost-circulation problems. Increased drilling rate as a result of reduced differential pressure at the hole bottom (Figure 2-1) was the most important benefit of underbalanced drilling enjoyed by these operators

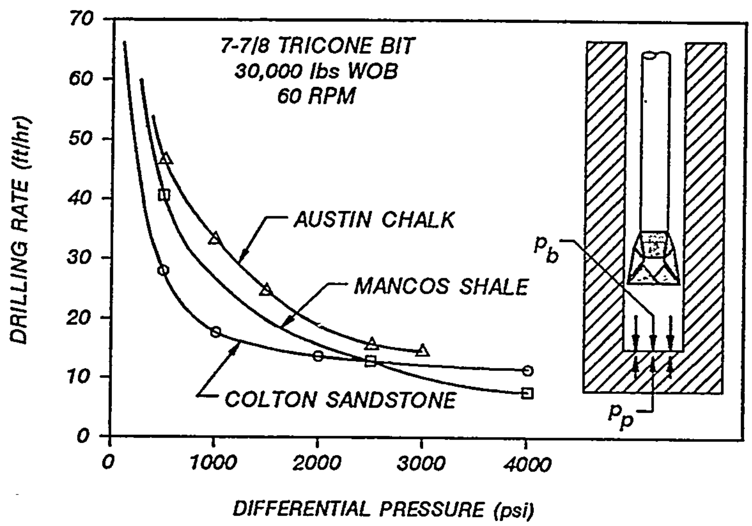

Figure 2-1. Differential Pressure and Drilling Rate (Moffitt, 1991)

The beneficial effects of reduced hydrostatic pressure with regard to increased ROP occurs at all bit weights, as illustrated in Figure 2-2. Other benefits of air drilling include reduced formation damage, reduced lost circulation, and fewer problems with differential sticking.

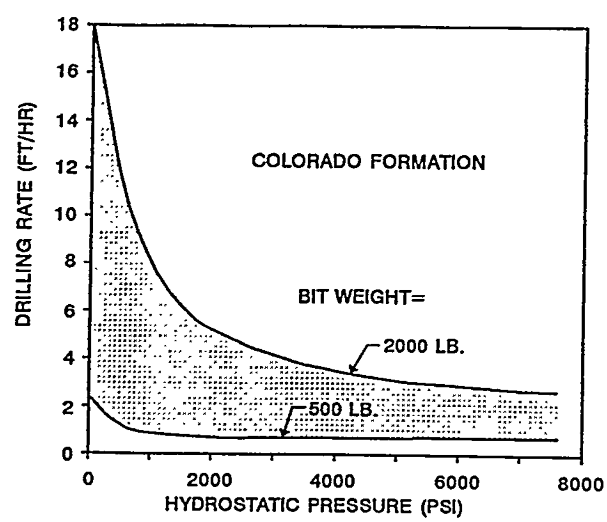

Figure 2-2. Hydrostatic Pressure and Drilling Rate (Murray and Cunningham, 1955)

Many tight gas reservoirs in the United States are attractive targets for underbalanced drilling because they are located in hard-rock country where tight (low-permeability) formations are more susceptible to formation damage from invasion of conventional drilling fluids.

Fluids lighter than water (i.e., specific gravity SG < 1) are also required when drilling underbalanced in underpressured or depleted reservoirs. Many types of fluids systems are used, ranging from 100% air to 100% liquid. All fluids with densities below 6.9 ppg (SG=0.83) used to date contain gas or air in some form (Figure 2-3).

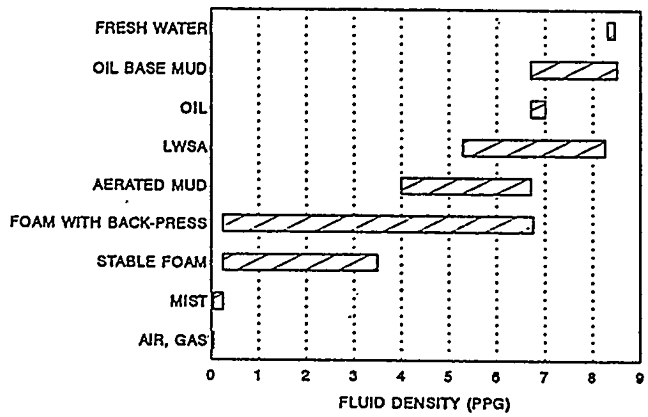

Figure 2-3. Fluid Density

During the 1950s and 1960s, the variety of drilling fluids was expanded to include mist, foam, and aerated fluids. Each of the two-phase systems shown in Figure 2-4 has been used successfully for drilling during the past four decades. However, the introduction of these two-phase fluids was accompanied by significantly increased difficulty in predicting fluid flow parameters with these compressible fluids.

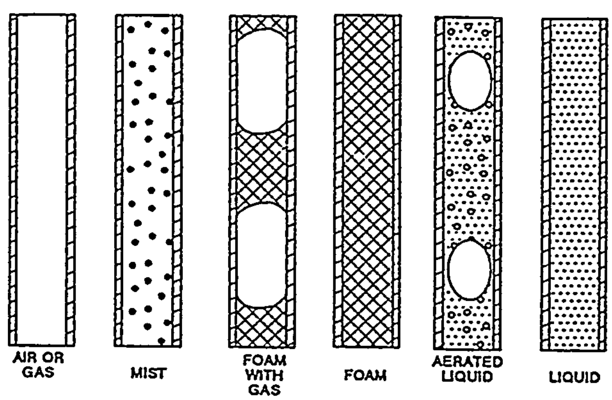

Figure 2-4. Flow Regimes Types (Lorenz, 1980)

The hydraulics for 100% liquid is relatively easy to predict because liquid can normally be assumed as essentially incompressible. One-hundred percent gas is harder to model, even though it is still one continuous phase, due to its compressibility. The hydraulics of mist and foam is the most difficult to model since these fluids are both compressible and two-phase. Foam is generally defined as any two-phase fluid with liquid as the continuous phase (having a gas emulsified in it), while mist is defined as a two-phase fluid having gas as the continuous phase (Figure 2-5). **Gas becomes the continuous phase at gas fractions above 97-98% by volume.**

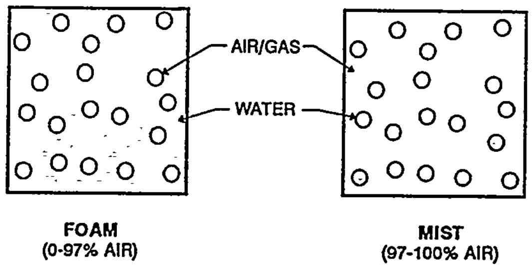

Figure 2-5. Fluid Phase Continuity

The advantages of various lightweight fluids are summarized in Table 2-1. Air, gas, and mist systems are compared to foam and proposed lightweight solid additive (LWSA) systems. As stated previously, the major advantage of using underbalanced fluids is increased drilling rates.

TABLE 2-1. Advantages of Underbalanced Fluids

AIR/GAS/MIST	FOAM/LWSA
HIGH DRILLING RATE	HANDLES WATER INFLUX
LOW CHEMICAL COSTS	IMPROVED HOLE STABILITY
	EXCELLENT HOLE CLEANING
EASY TO USE	REDUCED COMPRESSORS
	NO DOWNHOLE FIRES
REDUCED ENVIRONMENTAL IMPACT	CAN USE MUD PULSE MWD (LWSA)

Fluids having gas or air as the continuous phase have the advantage of simplicity, low costs for additives, and minimal equipment requirements. These fluids also lead to less environmental risk since there is minimal liquid waste disposal. Table 2-2 compares the disadvantages of underbalanced drilling fluids.

TABLE 2-2. Disadvantages of Underbalanced Fluids

AIR/GAS/MIST	FOAM/LWSA
NO WATER INFLUX	COST OF ADDITIVES
HOLE EROSION	MEASUREMENT/CALCULATION COMPLEXITY
DOWNHOLE FIRES	
HOLE INSTABILITY	

The primary disadvantage of air, gas or mist systems is their inability to handle formation fluid influxes. In practice, when an influx becomes too great for air or mist to handle, the fluid system must usually be switched to foam, aerated fluid, or 100% liquid.

Foams and the proposed LWSA muds (liquid muds with hollow glass spheres added) eliminate many of the problems associated with air, gas, and mist drilling fluids including borehole stability problems, extensive compressor requirements, and downhole fires and explosions. The greatest advantage of foam and LWSA mud is the ability to safely handle large influxes of oil or water from the formation.

Foam has the additional advantage of increased cuttings-carrying capacity. Figure 2-6 shows that, as the foam quality increases (i.e., the percent air increases), the lifting force increases. The maximum lifting force is achieved with 2 to 5% liquid, just within the region defined as a foam. As a foam becomes wetter, its viscosity decreases along with its ability to carry cuttings. As the fluid crosses over into a gas-continuous phase, it continues to effectively lift cuttings, but its ability to hold cuttings in suspension disappears at low velocities.

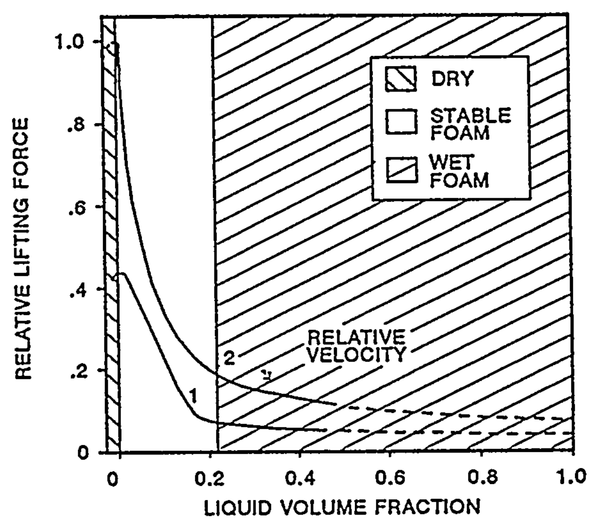

Figure 2-6. Foam Lifting Capacity (Beyer et al., 1972)

Aerated fluid can either be circulated down the drill pipe from the surface, or injected at some point in the drill-string casing annulus through a "parasite" string strapped to the outside of the casing (Figure 2-7). Air can also be injected down the annulus of dual-wall drill pipe. The injected air reduces pump pressure at the surface and lowers the hydrostatic head in the annulus.

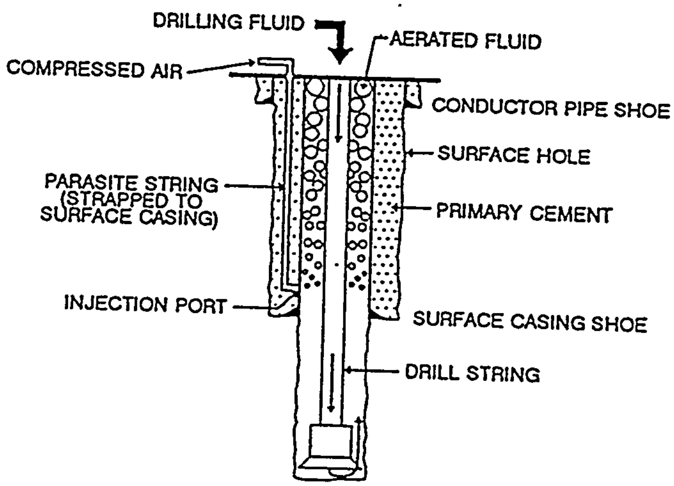

Figure 2-7. Parasite Injection String

Downhole fires and explosions are a problem when drilling with air, especially in long horizontal wells where days or weeks are spent drilling in oil or gas pay zones. If a flammable mixture of oxygen and natural gas or oil exists downhole, ignition can occur due to heat generated by friction or by sparks generated by the drill bit.

Although foam or aerated muds eliminate the potential for fires and explosions, their use is hindered by the increasingly complex hydraulics calculations and the high cost of foam chemicals. Prior to the availability of computers, it was nearly impossible to accurately calculate circulating pressures for compressible fluids. The tedious process of manually calculating hydraulics for foam systems was reduced by the development of nomographs and charts (Figure 2-8), rules-of-thumb, and correction factors that gave approximate answers. While these short-cut approaches allowed more broad application of foam drilling techniques, accuracy was decreased as was the engineers' ability to scientifically control these fluids.

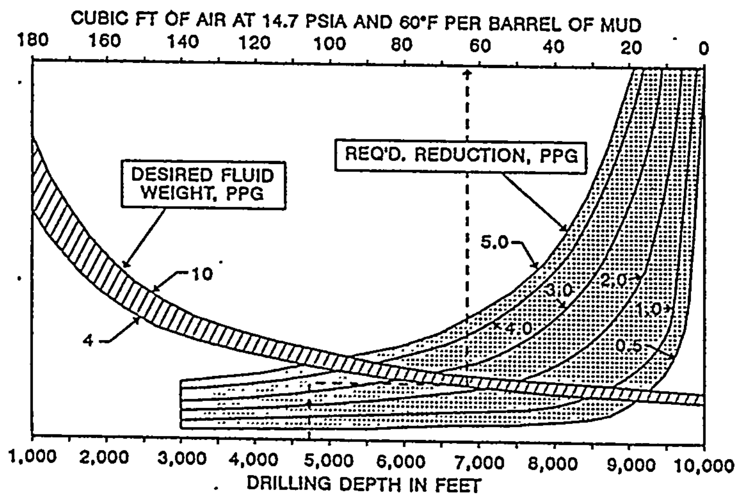

Figure 2-8. Volume Requirement Chart (Poettman and Begman, 1955)

An accurate hydraulics computer model is needed for foam drilling to allow engineers to better plan and drill wells. Chevron developed a mainframe computer model for foam circulation in the early 1970s that was state-of-the-art at that time, but its availability to the industry is limited.

Similarly, there is a need for incompressible drilling fluids that use solid additives (e.g., hollow glass spheres) to lighten the fluid. This type of fluid would overcome the severe fire, explosion, and corrosion risks associated with aerated drilling fluids. Fluids successfully incorporating lightweight solid additives (SG=0.3 to 0.6) would have many advantages over conventional aerated fluids including:

- Allow use of MWD tools
- Eliminate expensive compressors
- Reduce corrosion problems
- Eliminate downhole fires
- Eliminate the need for nitrogen
- Improve motor performance
- Improve hole stability
- Simplify pressure calculations
- Reduce drill-string vibrations

In the late 1960s, Russian scientists tested lightweight fluids that used hollow glass spheres to reduce fluid density. Data available on the spheres used in the Russian development are presented in Table 2-3.

TABLE 2-3. Russian Hollow Spheres

FIRST MANUFACTURED	—	1968
FIRST USE IN DRILLING	—	1970-71
MATERIAL	—	GLASS
COMPRESSIVE STRENGTH	—	2500-3600 PSI
SPECIFIC GRAVITY	—	0.35-0.40
AVERAGE DIAMETER	—	50-70 MICRONS

Oil-field service companies have used hollow glass spheres and other lightweight additives for years to reduce the density of cements and to decrease hydrostatic head in lost-circulation situations. Hollow glass spheres have not been used in lightweight drilling fluids outside of Russia until this DOE project.

2.2 OBJECTIVES

The first objective of this project is to develop a user-friendly PC foam drilling model, FOAM, that will accurately predict frictional pressure drops, cuttings-lifting velocity, foam quality, and other drilling variables. The model will allow operators and service companies to accurately predict pressures and flow rates required at the surface and downhole to efficiently drill oil and gas wells with foam systems.

The second objective of this project is to develop a lightweight drilling fluid using hollow glass spheres to reduce the density of the fluid and allow underbalanced drilling in low-pressure reservoirs. Since the resulting fluid will be incompressible, hydraulics calculations are greatly simplified, and expensive air compressors and boosters are eliminated. This lightweight fluid will also eliminate corrosion and the potential for downhole fires encountered with aerated fluids.

2.3 TASK SUMMARY

Phase I of the project "Development and Testing of Underbalanced Drilling Products" includes development of 1) a foam hydraulics model, FOAM, that will accurately calculate circulating pressures, cuttings lifting velocities, and compressor requirements, and 2) lightweight drilling fluids that utilize hollow glass spheres to reduce fluid density. The Contractor developed and began the verification process of an advanced computer model that will allow operators and service companies to accurately calculate and predict bottom-hole pressure changes resulting from foam quality variations. The model takes into account pressure, temperature, and the influence of foam quality on rheological parameters. The Contractor also researched and tested lightweight solid additives (LWSA) that can be added to conventional muds (using conventional equipment) to allow underbalanced drilling in low-pressure and other formations.

Tasks performed during the Phase I effort included identifying the most appropriate published mathematics related to the calculation of foam fluid hydraulics and incorporating them into the FOAM computer model. The model was then validated using existing measured data.

Phase I tasks performed to accomplish the second major objective included a determination of the potential market base for underbalanced drilling fluids, identification and laboratory testing of lightweight solid additives (LWSA), and yard testing of the LWSA using drilling-rig compatible equipment.

Phase II of the development will include field testing of both the foam drilling computer model and lightweight drilling fluids based on hollow glass spheres additives.

3. FOAM Model

3.1 BACKGROUND

A major hindrance to the increased application of underbalanced drilling is the lack of accurate and easy-to-use computer programs to predict wellbore hydraulics for drilling operations with air, mist, foam, and aerated mud. A user-friendly PC foam hydraulics program (FOAM) was developed as part of the Phase I effort. The initial version of FOAM handles foam circulation. It does not handle air and mist circulation in its current configuration.

A literature search (see references in Section 6) was used to identify all available mathematic models related to the pressure and flow characteristics of foam fluids, including predicting downhole pressures, flow rates, volumes, foam quality, foam rheology and cuttings carrying capacity. In addition, unpublished laboratory tests and mathematical models provided by Chevron and other sources were reviewed. The Chevron data and information were of significant value since Chevron spent many man-years and many millions of dollars developing foam computer models in the 1970s.

A PC Windows foam drilling model was developed for this project using the best mathematical models in the industry. The model was designed to be accurate, user-friendly, and in a format compatible with rugged well-site usage.

During Phase I, after initial software development, results generated by the FOAM program were validated by comparison with other foam models (e.g., Chevron's model) and available laboratory and field data. These results are presented in Section 3.4.

During Phase II, at least two extensive tests of the computer model will be conducted during foam drilling operations in the field. Surface and downhole data (e.g., pressures and temperatures) will be collected for comparison with the model's output.

3.2 FOAM THEORY

3.2.1 Rheological Models

Foam can be treated as a homogeneous fluid with both variable density and viscosity. During a foam operation, foam quality is dependent on the pressure and temperature along the tubing and annulus. The pressure has to be determined through the mechanical energy balance equation in which the frictional pressure drop term is impacted by the foam rheological model. It is therefore very important to have an accurate rheological model describing foam behavior.

The models most commonly used in the drilling industry to describe fluid behavior of non-Newtonian fluids are the Bingham plastic and power-law models. The equations to calculate the frictional pressure drop are listed in Bourgoyne et al. (1986) and API SPEC 10 (Beyer et al., 1972). The Bingham plastic model is defined in Eq. 3-1 and is illustrated in Figure 3-1. This type of fluid is characterized by a minimum shear stress, τ_y, that must be exceeded before the fluid will flow. Above this point, shear stress is proportional to shear rate.

$$\begin{aligned} \tau &= \mu_p\dot{\gamma} + \tau_y \quad ; \quad \tau > \tau_y \\ \dot{\gamma} &= 0 \qquad\qquad ; \quad \tau_y \geq \tau \geq -\tau_y \\ \tau &= \mu_p\dot{\gamma} - \tau_y \quad ; \quad \tau < -\tau_y \end{aligned} \tag{3-1}$$

Where:

τ = Shear stress
τ_y = Yield stress
μ_p = Fluid viscosity
$\dot{\gamma}$ = Shear rate

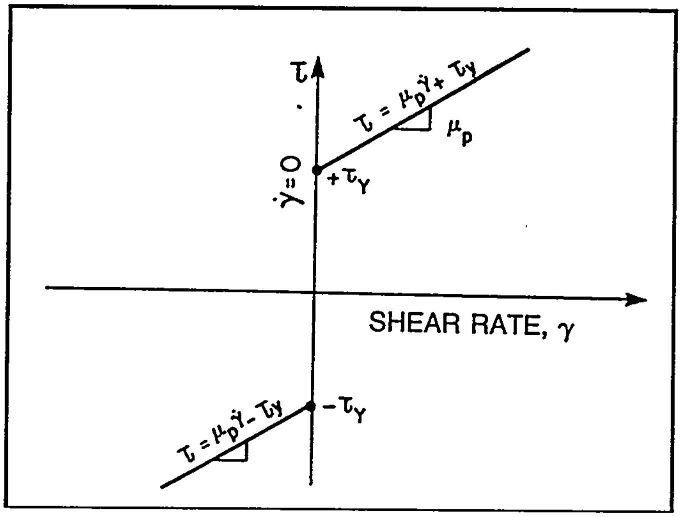

Figure 3-1. Shear Stress and Shear Rate for a Bingham Plastic Fluid (Bourgoyne et al., 1986)

The power-law model is defined in Eq. 3-2 and illustrated in Figure 3-2. Shear stress is not linearly related to shear rate for this type of fluid.

$$\tau = K\dot{\gamma}^n \tag{3-2}$$

Where: K = Consistency index, equivalent centipoise (see Bourgoyne et al., 1986)
n = Flow behavior index, dimensionless

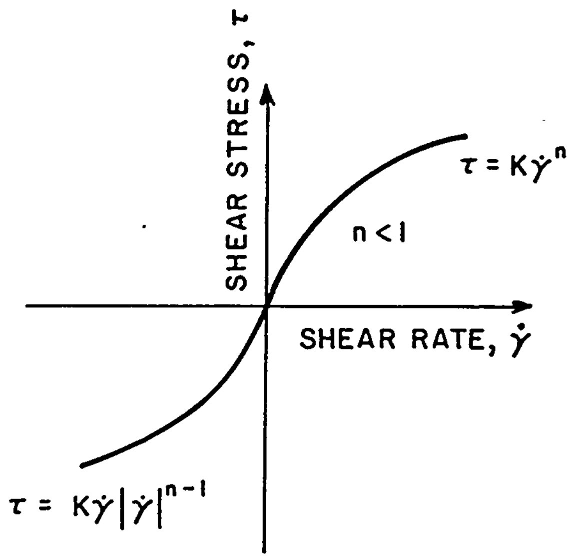

Figure 3-2. Shear Stress Vs. Shear Rate for a Power-Law Fluid (Bourgoyne et al., 1986)

Due to the unique complexity of foam flow, the above two rheology models cannot be readily applied to foam. This has motivated many investigators to apply traditional non-Newtonian continuum rheological approaches with modifications to describe the flow behavior of foams. Both theoretical treatment and experiment study are ongoing.

One theoretical approach to the rheology of foam was presented by Einstein (1906). His foam viscosity equation for foam quality between 0 and 54% is:

$$\mu_f = \mu(1.0 + 2.5\Gamma)$$

Where: μ_f = Viscosity of foam
μ = Viscosity of base liquid
Γ = Foam quality (fraction)

Hatschek's (1910A & B) equation for viscosity of bubble-interference foam for foam quality between 0 and 74% is:

$$\mu_f = \mu(1.0 + 4.5\Gamma)$$

His next theory describes the viscosity of foam caused by shear of the fluid between parallelepiped gas bubbles. The foam quality range for his second theory is from 75% to 100%. Foam viscosity in this range is expressed as follows:

$$\mu_f = \mu\left(\frac{1}{1 - \Gamma^{1/3}}\right)$$

It should be noted that the above equation does not apply at the limiting case of 100% foam quality.

Mitchell (1969) demonstrated that foam behaves as Bingham plastic fluid based on his experimental work in capillary tubes and empirically derived equations for foam viscosity.

$$\mu_f = \mu(1.0 + 3.6\Gamma) \quad , \quad 0 \le \Gamma \le 54\%$$

$$\mu_f = \mu\left(\frac{1}{1 - \Gamma^{0.49}}\right) \quad , \quad 54\% \le \Gamma \le 100\%$$

Again, this equation does not apply for pure gas flow.

Krug presented plastic viscosities and yield strengths of a sample foam as a function of foam quality (Table 3-1).

TABLE 3-1. Plastic Viscosity and Yield Strength of Sample Foam (Krug 1971)

QUALITY (%)	PLASTIC VISCOSITY (cp)	YIELD STRENGTH (Lbf/100 ft^2)
0	1.02	0
0-25	1.25	0
25-30	1.58	0
30-35	1.60	0
35-45	2.40	0
45-55	2.88	0
55-60	3.36	0
60-65	3.70	14
65-70	4.30	23
70-75	5.00	40
75-80	5.76	48
80-86	7.21	68
86-90	9.58	100
90-96	14.38	250

Beyer et al. (1972) first formulated a foam rheological model from laboratory and pilot-scale experimental data. Their observations suggested that foam behaves like a Bingham plastic fluid. Their study did not demonstrate a dependence of τ_y (shear stress yield) on liquid volume fraction or foam quality.

Sanghani and Ikoku (1983) experimentally studied foam rheology with a concentric annular viscometer that closely simulated actual hole conditions. They concluded that foam is a power-law pseudoplastic fluid with both flow behavior index n and flow consistency K, which are both functions of foam quality. Fluid properties of another sample foam for different foam qualities are listed in Table 3-2.

TABLE 3-2. Flow Properties for Sample Foam (Okpobiri and Ikoku 1986)

Quality		K'_g	Flow Consistency Index, K	
Γ Range	Γ Average	(lbf sec$^{n'}$/sq ft)	(lbm sec$^{n'-2}$/ft)	n'
0.96 to 0.977	0.97	0.0946	2.566	0.326
0.94 to 0.96	0.95	0.1228	3.323	0.290
0.91 to 0.92	0.915	0.2262	6.155	0.187
0.89 to 0.91	0.90	0.2079	5.647	0.200
0.84 to 0.86	0.85	0.1828	4.958	0.214
0.79 to 0.81	0.80	0.1344	3.635	0.262
0.77 to 0.78	0.775	0.1236	3.343	0.273
0.74 to 0.76	0.75	0.1078	2.918	0.295
0.72 to 0.73	0.715	0.1061	2.8716	0.293
0.69 to 0.71	0.70	0.1026	2.777	0.295
0.65 to 0.69	0.67	0.1022	2.766	0.290

From a review of the literature, some researchers found that the power-law model was statistically superior to the Bingham plastic model in correlating data. Others' experiments showed that foam more closely obeys the Bingham plastic model. The computer program developed for this project includes both rheological models for foam and allows the user to choose which one to use. Measured laboratory data available for program validation matches the Chevron rheology model best.

3.2.2 Foam Flow Equations

In this section, the theoretical background on equations of state and flow equations for compressible foam flow are presented. In the special case of a two-phase system, such as foam, in which one phase (gas) is finely and uniformly dispersed in the other (liquid), homogeneous fluid can be assumed and no equation is required for the phase interface. Foam consists of a compressible component (gas) and imcompressible component (liquid). The incompressible component is relatively easier to handle because of its constant density. The compressible gas requires much more attention, since its density depends on temperature and pressure. Pressure is coupled with both liquid and gas volume fractions. An improved version of Lord's (1981) pressure drop equation and Spoerker et al.'s (1991) method is used in the following equation derivation. Friction factor is calculated along the wellbore rather than assumed to be constant.

(1) *Equations of State*

The relationship between the variation in density of a fluid with pressure and temperature is termed the equation of state. For engineering purposes, the most practical form of the equation of state for a real gas is given by (Grovier and Aziz 1987):

$$V_g = \frac{ZRT}{M_g P} \tag{3-3}$$

Where V_g = Specific volume of gas
Z = Gas compressibility factor
M_g = Molecular weight of gas (lbm/lb-mole)

R = Gas constant, 10.73 $\frac{(\text{psia})\cdot(\text{ft}^3)}{(\text{lb-mole})(°\text{R})}$

T = Absolute temperature, (°R)

P = Absolute pressure, (psia)

Another equation of state for gas is the Virial equation truncated after the second term (Reid et al. 1987).

$$V_g = \frac{RT}{M_g}\left(\frac{1}{P+P^e} + B'\ldots\right) \tag{3-4}$$

Where P^e = Excess pressure due to surface tension

$= \frac{4\sigma}{r}$ (σ = surface tension, r = bubble radius)

B' = Modified second Virial coefficient

$$= \left(\frac{1}{RT}\right)\cdot \lim_{\frac{1}{v}\to 0}\left(\frac{\partial z}{\partial \frac{1}{v}}\right)_T$$

The excess pressure can be neglected for engineering calculations. This yields:

$$V_g = \frac{RT}{M_g}\left(\frac{1}{P} + B'\right) \tag{3-5}$$

For downward flow inside tubing, assume that at inlet the mass rate of gas is m_g and that of liquid is m_l. The mass fraction of gas is defined as:

$$W_g = \frac{m_g}{m_g + m_l} \tag{3-6}$$

Then the specific volume of foam mixture can be expressed as

$$V = W_g V_g + (1 - W_g)V_l \tag{3-7}$$

Where: V = Specific volume of foam

V_l= Specific volume of liquid

Combining equation (3-3) or (3-5) and (3-7) will lead to the equation of state for downward foam flow inside tubing:

$$V = \frac{a}{P} + b \tag{3-8}$$

The coefficients a and b are defined in Table 3-3.

TABLE 3-3. Coefficients in Equation of State for Downward Foam Flow

GAS EQUATIONS	a	b
Engineering Gas Law	$\frac{W_g ZRT}{M_g}$	$(1 - W_g)V_l$
Virial Equation	$\frac{W_g RT}{M_g}$	$\frac{W_g RTB'}{M_g} + (1 - W_g)V_l$

For upward flow in the annulus, the foam is mixed with rock cuttings. There are three phases in the mixture. Liquid and cuttings are incompressible, while the gas phase is compressible. The equation of state for gas remains the same as Eq. (3-3) or (3-5).

In addition to liquid and gas injection at the top of the tubing, the mass rate of solid cuttings is not negligible. The mass rate of cuttings can be estimated using the following equation.

$$m_s = 1.33 \times 10^{-5} D_h^2 \cdot ROP \cdot \rho_s \qquad \text{(lbm/s)} \qquad (3\text{-}9)$$

Where:

D_h = Open-hole diameter (in.)
ROP = Rate of penetration (ft/hr)
ρ_s = Rock density (ppg)

The mass fractions of the three components are:

$$W_g = \frac{m_g}{m_g + m_l + m_s}$$

$$W_l = \frac{m_l}{m_g + m_l + m_s} \qquad (3\text{-}10)$$

$$W_s = \frac{m_s}{m_g + m_l + m_s}$$

The specific volume of foam and cuttings mixture can be expressed as

$$V = W_g V_g + W_l V_l + W_s V_s \qquad (3\text{-}11)$$

Combining Eq. (3-3) or (3-5) with (3-11) will lead to the equation of state for the upward foam flow in the annulus:

$$V = \frac{a}{P} + b \qquad (3\text{-}12)$$

The coefficients a and b are defined in Table 3-4.

TABLE 3-4. Coefficients in Equation of State for Annular Upward Foam Flow

GAS EQUATIONS	a	b
Engineering Gas Law	$\frac{W_g ZRT}{M_g}$	$W_l V_l + W_s V_s$
Virial Equation	$\frac{W_g ZRT}{M_g}$	$\frac{W_g RTB'}{M_g} + W_l V_l + W_s V_s$

Note that if rate of penetration is zero, W_s will be equal to zero, and a and b in equation (3-12) are identical to those in Table 3-3.

(2) *Mechanical Energy Equations*

Once the equations of state for foam have been established, the next step is to use the momentum and energy equations to analyze the dynamic foam behavior. The mechanical energy equation may be considered either a consequence of the momentum equation or a reduced form of the total energy equation.

For downward flow inside tubing, the differential mechanical energy balance equation is

$$\frac{u\,du}{g_c} - \frac{g\,d(VD)}{g_c} + V\,dp + \frac{2u^2 f\,d(MD)}{g_c D} = 0 \tag{3-13}$$

where
- u = Average velocity of the foam, ft/s
- f = Fanning friction factor
- g = Acceleration due to gravity
- g_c = 32.2 (ft-lbm)/(lbf-s^2)
- MD = Measured Depth, ft
- VD = Vertical Depth, ft
- D = Tubing ID, in.

The average velocity of the foam, u, can be obtained through the continuity equation. In terms of specific volume, it can be expressed as:

$$u = CV = \frac{ac}{p} + bc \tag{3-14}$$

where $$C = \frac{4}{\pi D^2}(m_g + m_l) \tag{3-15}$$

After substituting Eq. (3-14) into Eq. (3-13), the differential mechanical energy balance takes the form

$$\frac{dp}{d(MD)} = F_p(MD, p) \tag{3-16}$$

For upward flow in the annulus, the differential mechanical energy balance equation takes the form

$$\frac{u\ du}{g_c} - \frac{g\ d(VD)}{g_c} + V\ dp - \frac{2u^2 f\ d(MD)}{g_c(D_h - D_p)} = 0 \tag{3-17}$$

where D_h = Open-hole diameter, in.
D_p = Drill-pipe O.D., in.

The average velocity of the foam in the annulus is also described by Eq. (3-14). However, the variable C for upward annular flow is

$$C = \frac{4}{\pi(D_h^2 - D_p^2)}(m_g + m_l + M_s) \tag{3-18}$$

Similar substitution will yield the following differential mechanical energy balance in the upward annular flow:

$$\frac{dp}{d(MD)} = F_A(MD, p) \tag{3-19}$$

Equations (3-16) and (3-19) can be solved numerically. The back pressure, which is known, serves as a boundary condition for Eq. (3-19). Numerical techniques are used to calculate a sequence of pressure values corresponding to discrete measured depths.

(3) Pressure Drop Across Nozzles

To calculate the pressure drop through a short constriction, such as a bit nozzle (Figure 3-3), it generally is assumed that (1) the change in elevation is negligible, (2) the velocity upstream of the nozzle is negligible, and (3) the frictional pressure loss across the nozzle is negligible. Thus, Eq. 3-13 becomes

$$\frac{u\ du}{g_c} + V\ dp = 0 \tag{3-20}$$

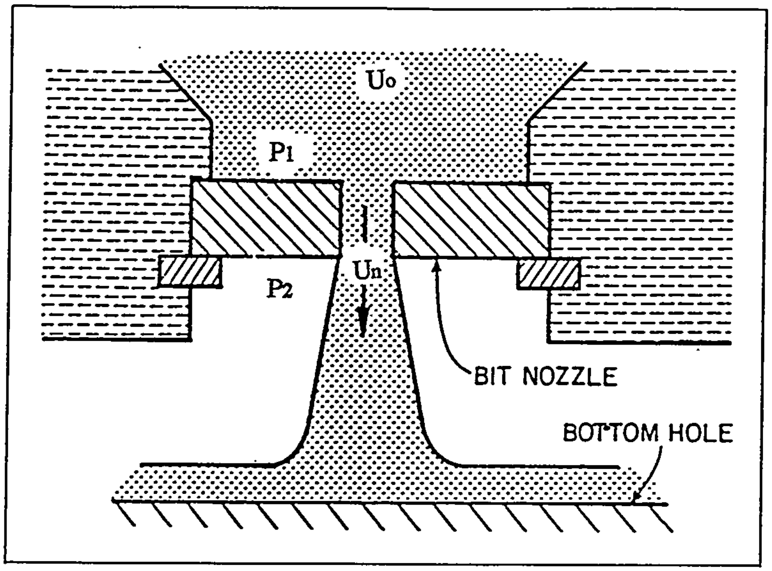

Figure 3-3. Flow Through a Bit Nozzle (Okpobiri and Ikoku, 1986)

Expressing this equation in practical field units of pounds per square inch, pounds per gallon and feet per second gives

$$dp + 0.00162 \frac{u\,du}{V} = 0 \qquad (3\text{-}21)$$

Substituting Eq. 3-14 and integrating yields

$$\frac{1}{b}(P_2 - P_1) - \frac{a}{b^2} \ln \frac{\left(P_2 + \frac{a}{b}\right)}{\left(P_1 + \frac{a}{b}\right)} + 8.1 \times 10^{-4}\, U_n^2 = 0 \qquad (3\text{-}22)$$

where P_1 = Pressure upstream of the nozzle
P_2 = Bottom-hole pressure
U_n = Nozzle velocity

Nozzle velocity U_n is defined as

$$U_n = \frac{ac'}{P_2} + bC' \qquad (3\text{-}23)$$

where

$$C' = \frac{m_g + m_l}{\text{Total Flow Area of Nozzles}} \qquad (3\text{-}24)$$

Eq. (3-22) can be solved numerically to obtain the pressure upstream of nozzle P_1. The bottom-hole pressure P_2 is calculated from Eq. (3-19) beforehand.

3.2.3 Influx Modeling

One of the advantages of foam drilling is the low bottom-hole pressure, which increases the rate of penetration. However, influxes of gas, water or oil can occur as a result of low bottom-hole pressure. Gas, water or oil flowing into wellbore will change the existing foam system, resulting in a change of the pressure profile inside the tubing as well as in the annulus.

The total liquid density may be calculated from the rates and densities of injected liquid and those of water/oil influxes.

$$\rho_L = \rho_o f_o + \sum_{i}^{N} \rho_i f_i \tag{3-25}$$

where ρ_o = Density of inlet liquid

$$f_o = \frac{q_o}{q_o + \sum_{i=1}^{N} q_i} \tag{3-26}$$

$$f_i = \frac{q_i}{q_o + \sum_{i=1}^{N} q_i} \tag{3-27}$$

q_o = Liquid injection rate

q_i = Water/oil influx rate

N = Number of water/oil influxes

The final liquid viscosity can be calculated in a similar fashion.

Molecular weight of the mixture of injected gas and influx gas can be calculated using weighting factors similar to those used for calculating liquid density and viscosity. That is

$$Mg = Mg_o f_o + \sum_{i=1}^{M} Mg_i f_i \tag{3-28}$$

Where Mg_o = Molecular weight of inlet gas

$$f_o = \frac{mg_o}{mg_o + \sum_{i=1}^{M} mg_i} \tag{3-29}$$

$$f_i = \frac{mg_i}{mg_o + \sum_{i=1}^{M} mg_i} \tag{3-30}$$

mg_o = Mass rate of inlet gas
mg_i = Mass rate of influx gas
M = Number of gas influxes

Equations of state for gas and foam flow equations for annular upward flow should use these adjusted parameters from influx point above.

3.2.4 Cuttings Carrying Capacity

Another advantage of foam drilling is its high cuttings carrying capacity. For example, both the yield point and plastic viscosity of Bingham plastic foam will increase as the foam quality increases. This will increase the effective viscosity of foam and enhance the cuttings carrying capacity. The particle slip velocity, which defines the rate at which a cutting of a given diameter and specific gravity settles out of the fluid, is a concern to the drilling engineer. The FOAM program utilizes the Moore's (Bourgoyne et al. 1986) correlation to determine the slip velocity through a foam system.

Moore's correlation involves obtaining the apparent Newtonian viscosity as follows:

$$\mu_a = \frac{K}{144}\left(\frac{D_h - D_p}{U_a}\right)^{1-n}\left(\frac{2+\frac{1}{n}}{0.0208}\right)^{n} \tag{3-31}$$

where U_a = Mean annular velocity

The particle Reynolds number is:

$$N_{Re} = \frac{928\rho_f V_{sl} d_s}{\mu_a} \tag{3-32}$$

Where ρ_f = Foam weight, lb/gal
d_s = Particle diameter, in.
V_{sl} = Slip velocity, ft/s

In Eq. (3-32) the slip velocity V_{sl} is undetermined and is obtained by iteration. For Reynolds numbers greater than 300, the slip velocity is:

$$V_{sl} = 1.54\sqrt{d_s\frac{\rho_s - \rho_f}{\rho_f}} \tag{3-33}$$

where ρ_s = Solid density, lb/gal

For Reynolds numbers of 3 or less, the slip velocity becomes:

$$V_{sl} = 82.87 \frac{d_s^2}{\mu_a} (\rho_s - \rho_f) \tag{3-34}$$

For Reynolds numbers between 3 and 300, the slip velocity approximation is given by:

$$V_{sl} = \frac{2.90\, d_s\, (\rho_s - \rho_f)^{0.667}}{\rho_f^{0.333}\ \mu_a^{0.333}} \tag{3-35}$$

Cuttings transport ratio is defined by the following equation:

$$F_t = 1 - \frac{V_{sl}}{U_a} \tag{3-36}$$

For positive cuttings transport ratios, the cuttings will be transported to the surface with more or less transport efficiency. For negative cuttings transport ratios, cuttings will become concentrated in the annulus. Therefore, this is an excellent measure of the carrying capacity of a particular drilling mud.

3.3 PROGRAM OPERATION

The FOAM program is written for use under Microsoft Windows for ease of use by drilling engineers and field personnel. Published and field-tested mathematical models are used in the hydraulics model (see Section 3.2). The program calculates compressor requirements, pressure drops, pressure gradients, bottom-hole pressures, annular velocities, ECDs, cuttings lifting velocities, and other wellbore parameters as a function of gas and liquid properties and injection rates.

The user can also observe changes in critical drilling parameters as a function of changes in liquid and gas injection rates and choke pressures. This is useful when troubleshooting field wells (e.g., poor hole cleaning). Real-time use of the model in the field will allow drillers and engineers to detect, evaluate, and correct problems before they escalate into major catastrophes (e.g., stuck pipe, twistoffs, and blowouts).

Example input and output screens from FOAM are presented in this section to demonstrate program operation. The first program screen (Figure 3-4) is the Project Window, which also serves as the main window for program operation. Within this window, the user specifies the data files to be used for the calculations. The FOAM model uses four sets of input data to better organize well, drilling and rheological parameters. Data can be stored and retrieved as a single Project, or as four separate input data files retrieved in any combination. Program calculation (Run) is initiated from this window.

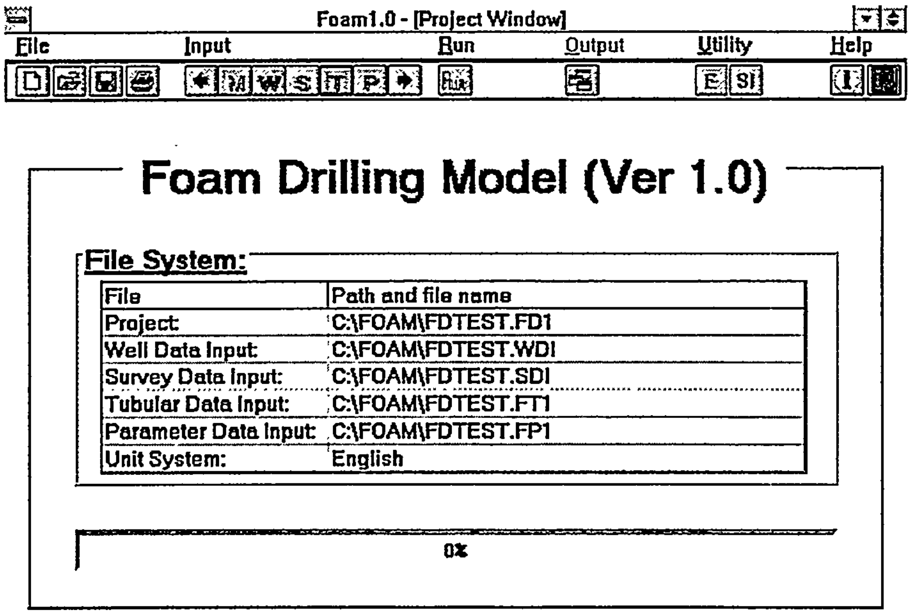

Figure 3-4. FOAM Project Window

Each of the four sets of input data is stored in a separate file. The first input file is the Well Data Input (Figure 3-5). This window stores well and field names, and other documentation to identify the specific case being calculated. These entries are optional and are not required for program operation.

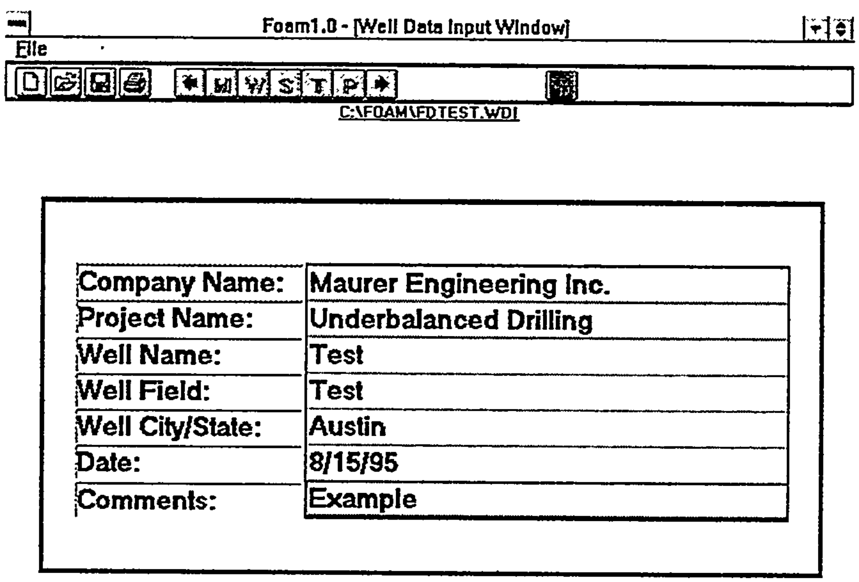

Figure 3-5. FOAM Well Data Input Window

The wellbore profile is described in the Survey Data Input window (Figure 3-6). Inclination and azimuth are recorded at the corresponding survey point measured depth. Options allow input of survey data in any of several systems of units, based on the user's preference.

drilling rate, cuttings size, rock density, temperature gradients, backpressure, and gas and fluid rheological data. The preferred mathematical models for equation of state and rheology are also selected from this window (see Section 3.2).

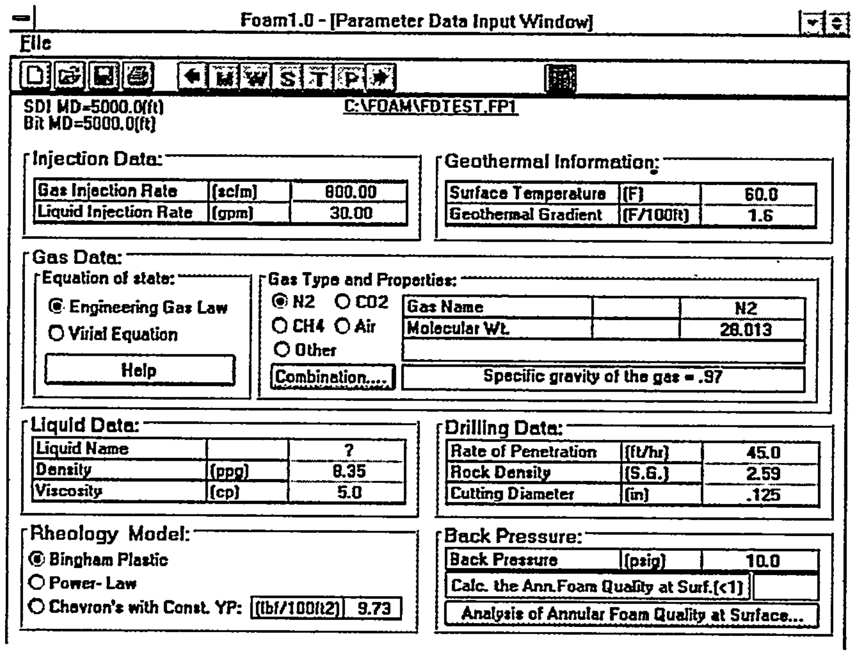

Figure 3-8. FOAM Parameter Data Input Window

The model can handle differing combinations of gases, which is an important feature when required because the density of individual gases varies considerably, thus affecting circulation pressures. Gas and liquid injection rates are the most important parameters controlling pressure drops and cuttings lifting rates.

After the four data input screens shown in Figures 3-5 to 3-8 are completed, the calculations are performed by selecting "Run" from the Project Window. Because the program is designed to handle true foams (i.e., foam quality <97%), for cases where the foam quality exceeds 97% over more than 500 feet of the annulus, the user is given a warning that the results may not be accurate. FOAM then "tiles" up the output screens, allowing the user to click on the individual output screen(s) of interest. Figure 3-9 shows an example of output data for a 7⅞-in. well drilled with foam to a depth of 5000 feet.

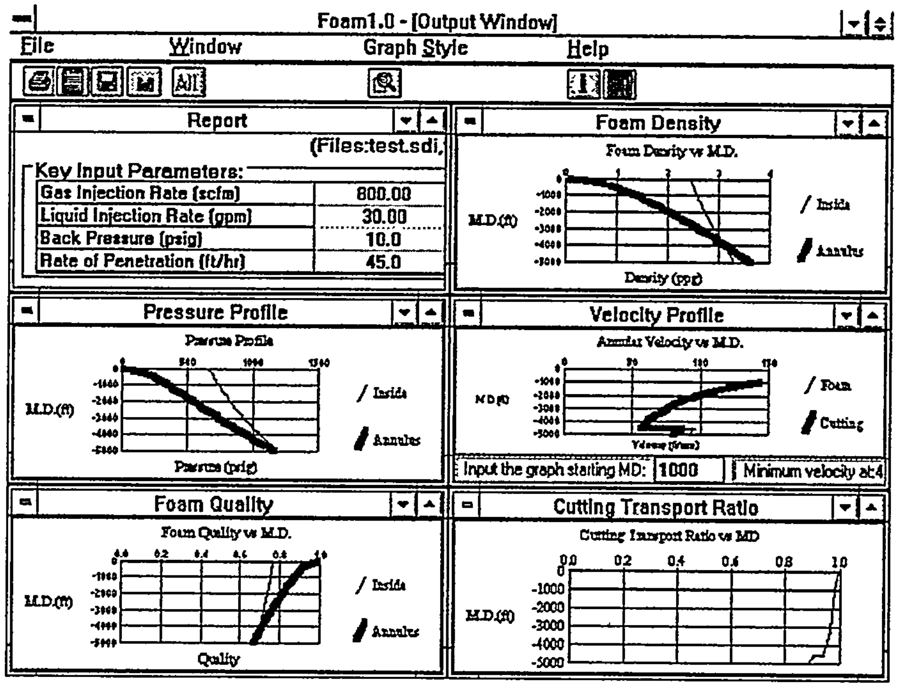

Figure 3-9. FOAM "Tiled" Output Window

A full-screen version of the foam pressure profile is shown in Figure 3-10. In this example, the pressure increases from 665 psi at the compressor to 1180 psi at the hole bottom. The pressure then decreases as aerated fluid flows up the annulus and expands, registering a pressure of 10 psi at the surface choke (as specified by the user). Determining this pressure profile is essential to ensure that frac pressures are not exceeded and to determine whether wellbore pressure is below formation pressure.

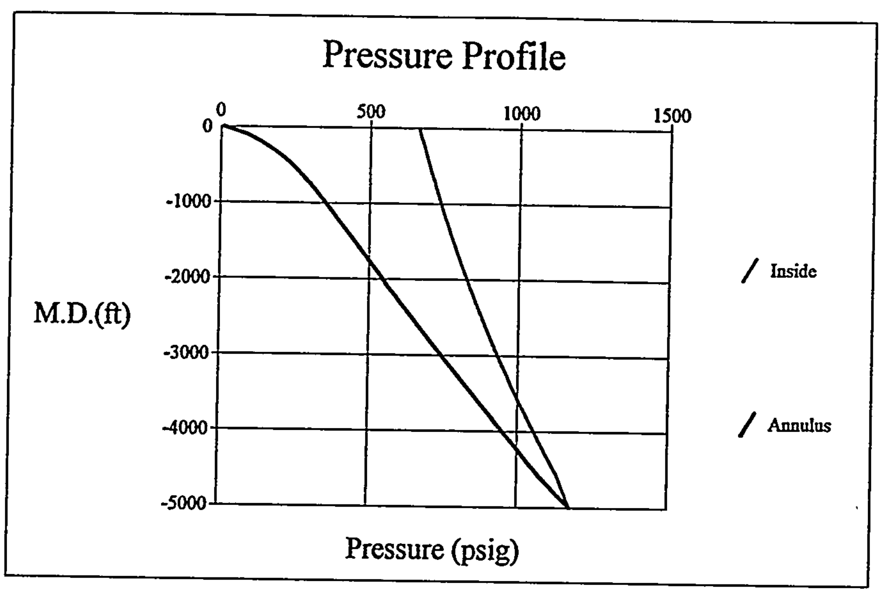

Figure 3-10. FOAM Wellbore Pressure Profile

Foam quality is a measure of the relative volume of gas in the mud, with 1.0 representing 100% gas and 0.0 representing 100% liquid. Foams are usually defined as mixtures with qualities ranging from 0 to 0.97, mists as 0.97 to 0.999, and air or gas as 1.0.

Foam quality for the example drilling operation decreases from 0.76 at the surface to 0.68 at the hole bottom (Figure 3-11). Quality then increases to 0.99 as the compressible fluid flows up the annulus and expands.

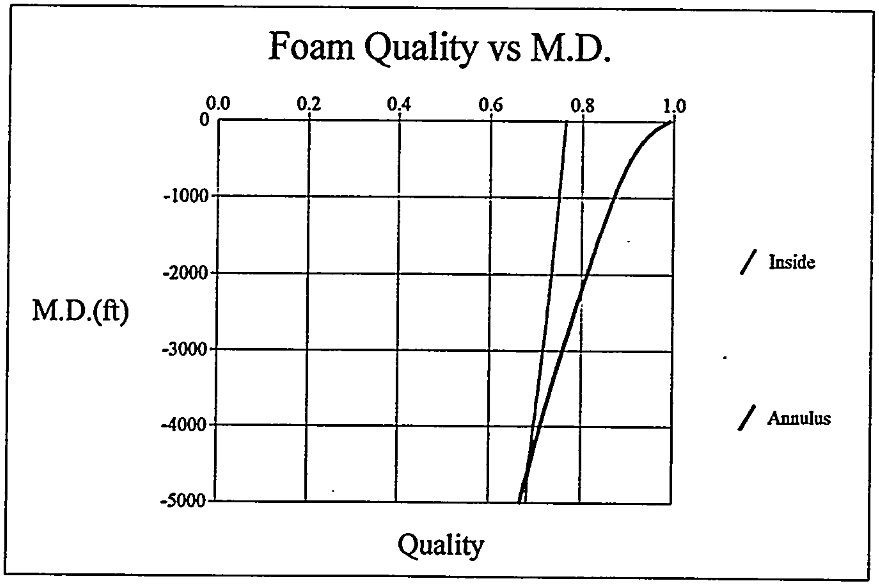

Figure 3-11. FOAM Quality Profile

Air drillers are very interested in foam quality since this parameter controls the cuttings lifting ability of the foam. Experience has shown drillers that a good rule-of-thumb is to not allow the foam quality to fall below about 55% at the hole bottom. Below this range, cuttings lifting capacity decreases significantly.

Figure 3-12 shows that foam density for this example increases from 2.4 ppg at the surface to 3.3 ppg at the hole bottom, due to the compressibility of the aerated fluid. After the foam exits the bit nozzle, its density jumps from 3.3 to 3.7 ppg due the addition of drill cuttings to the fluid. Foam density decreases to nearly zero as the foam flows up the annulus and the gas expands.

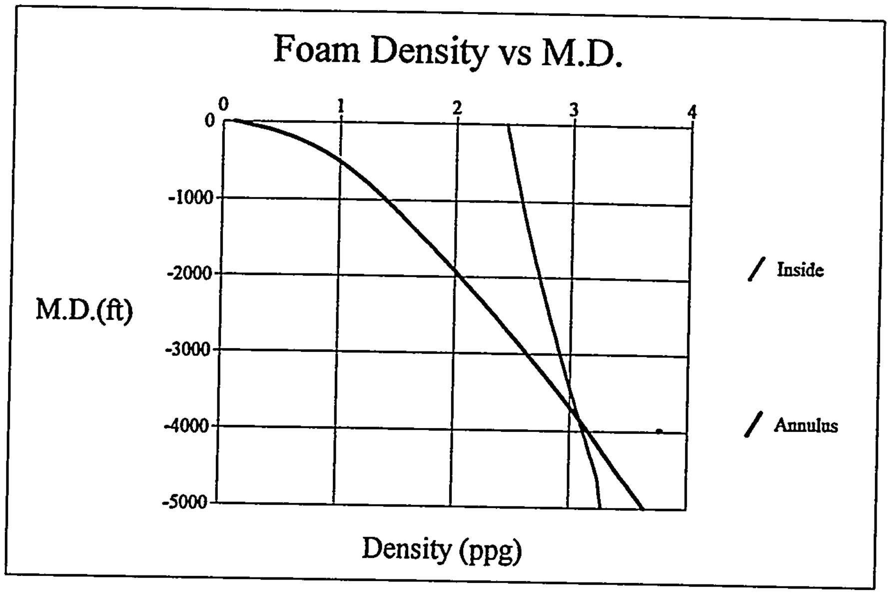

Figure 3-12. FOAM Density Profile

Cuttings lifting velocity in the annulus is of major concern with aerated fluids because poor hole cleaning is often present near the bottom due to the compressibility of the fluids, which results in low flow rates near the bottom of the hole. FOAM calculates cuttings lifting velocities in the annulus, as shown in Figure 3-13. In this 7⅞-in. hole, cuttings lifting velocity increases from a low value at the hole bottom to 2100 ft/min at the surface as the gas expands.

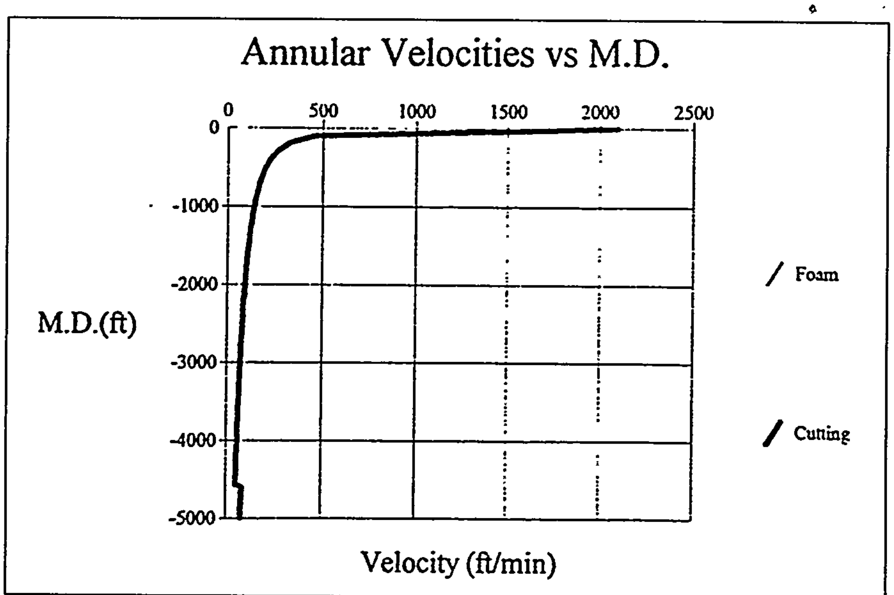

Figure 3-13. FOAM Cuttings Lifting Velocity Profile

Accurate calculation of cuttings lifting velocity is critical for conducting safe and efficient drilling operations since poor hole cleaning is a major problem with air, gas, and mist drilling. Cuttings lifting problems are most critical near the hole bottom where the velocities are least. FOAM allows the user to expand the scale of the bottom portion of the cuttings lifting curve to zoom in on the problem areas (Figure 3-14).

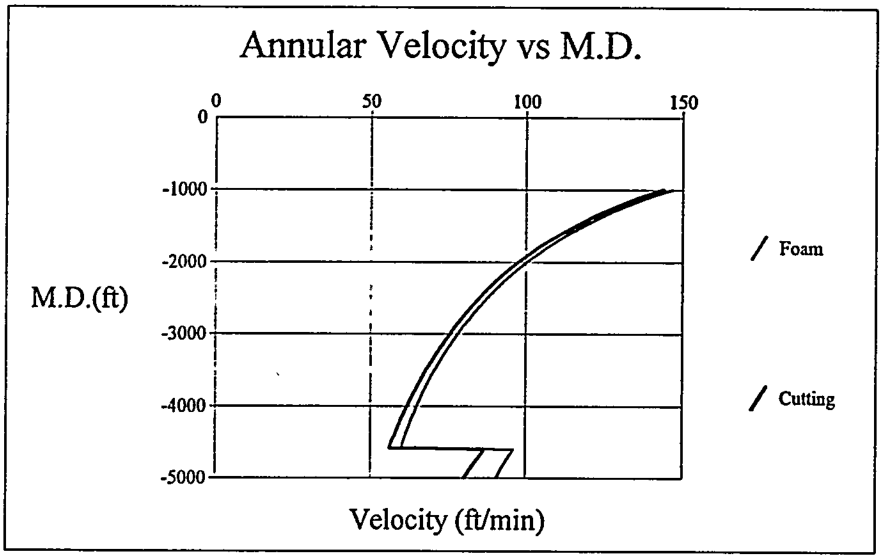

Figure 3-14. Cuttings Lifting Velocities Near Bottom

Figure 3-14 shows that cuttings rise at a lower velocity than the foam due to cuttings settling in the foam. In this example, cuttings lifting velocity is lowest (56 ft/min) at the top of the drill collars due to the reduction in pipe diameter at this point (i.e., larger annular area and reduced fluid velocity). Large cuttings often cannot be lifted beyond this point, remaining there until they are reground to a smaller size. This explains why air cuttings are often fine powder, while foam cuttings are much larger (e.g., ⅛- to ¼-in. diameter) due to better lifting capacity of foams.

The cuttings transport ratio profile can also be viewed to gauge cuttings lifting efficiency. For the example well (Figure 3-15), the ratio of cuttings velocity to fluid velocity ranges from a low of 0.88 at the bit to almost 1.0 at the surface. A positive transport ratio indicates that the cutting is being lifted up the annulus. General industry experience suggests that good hole cleaning can be achieved at cuttings transport ratios exceeding about 0.5-0.6.

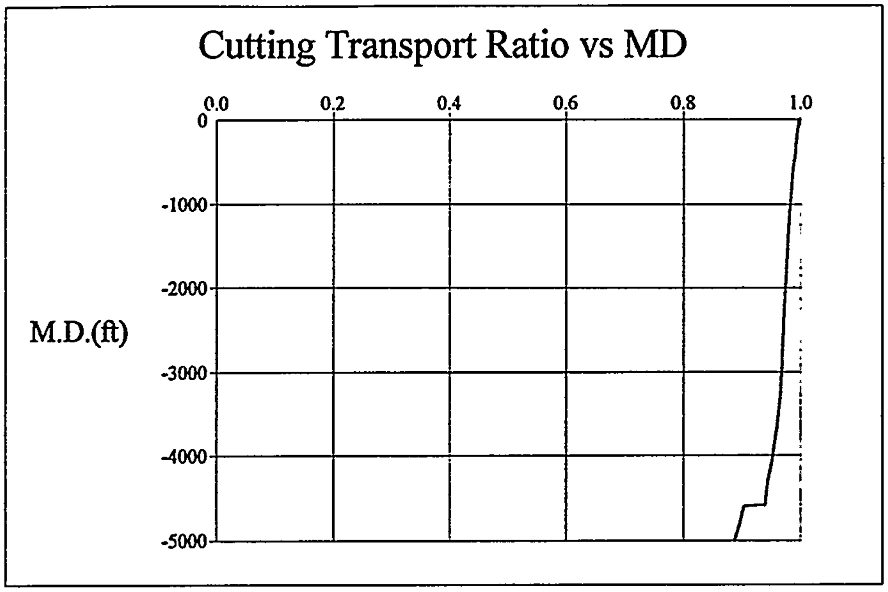

Figure 3-15. FOAM Cuttings Transport Ratio Profile

FOAM includes another format for viewing the output profiles. Under the wellbore schematic option, each output profile can be viewed graphically within the wellbore profile. Color variations are used to illustrate the rate of change of the quantity under consideration. The foam quality profile is depicted in Figure 3-16 for the example well.

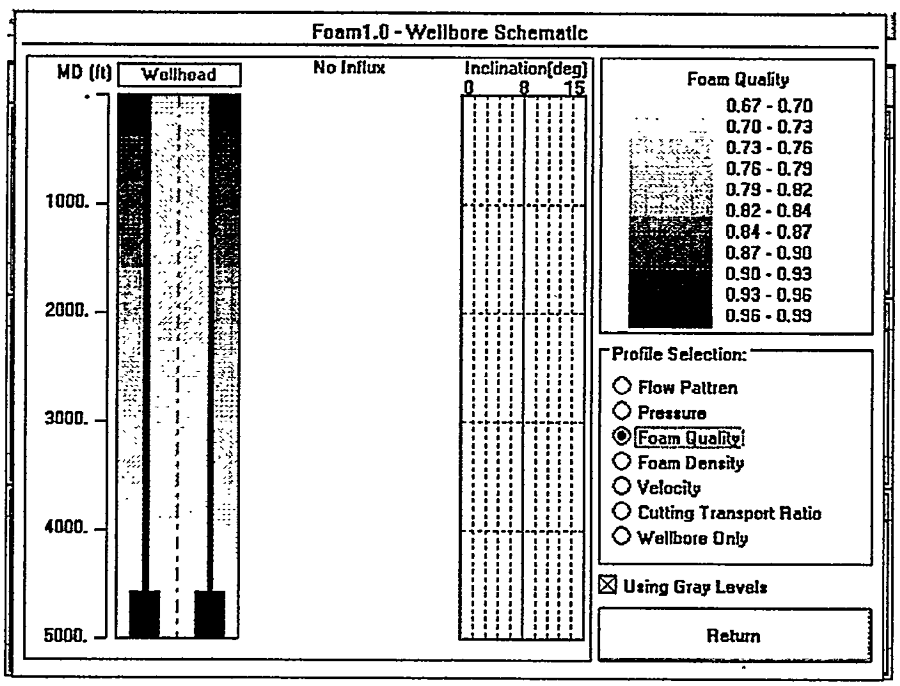

Figure 3-16. FOAM Profile Visualization

FOAM's output section also includes a sensitivity analysis feature that allows drilling engineers to observe the effects of changes in air and liquid injection rates and choke pressure on various downhole parameters (Figure 3-17). These are the variables that can be adjusted in the field if problems occur, so they have been combined into this separate screen for ease of use in planning and troubleshooting wells. As changes are made in these variables, impacts of those changes can be viewed immediately in the four graphs, allowing quick optimization of the variables.

Figure 3-17 shows sensitivity analysis output corresponding to the hole bottom (5000 ft) for the 7⅞-in. example well.

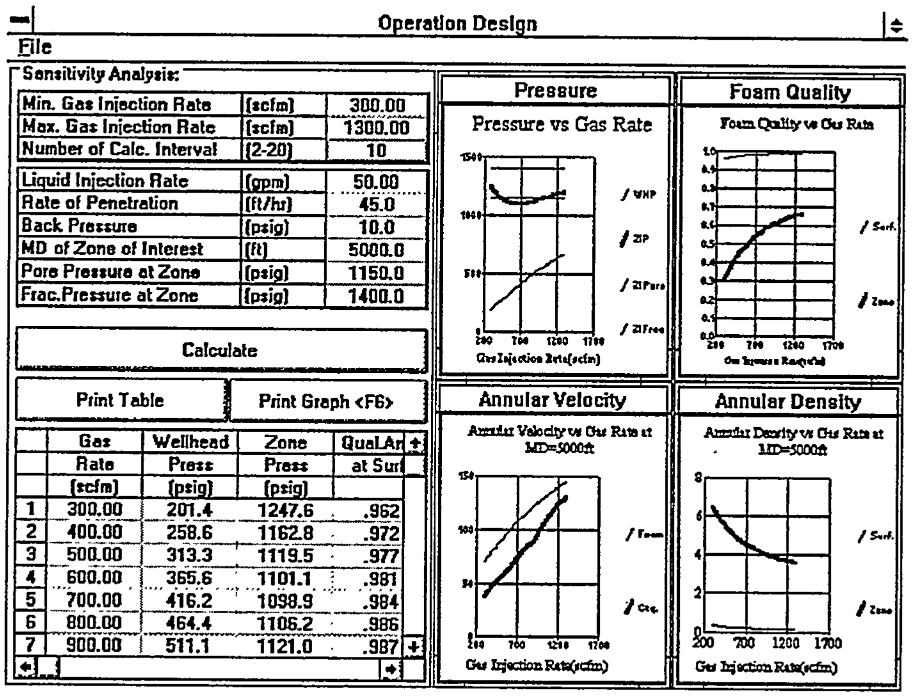

Figure 3-17. FOAM Sensitivity Analysis Screen

3.4 PROGRAM VALIDATION

Air- and foam-drilling service companies were contacted to determine which computer models, if any, were in general use within the industry. It was found that most service companies use either the Chevron model under license, or other models based on the Chevron model. At least one service company uses a proprietary spreadsheet model developed by an independent third party. These proprietary models are not generally available to the industry, hence the need for the FOAM model to increase the industry's access to design tools for underbalanced drilling operations.

3.4.1 Comparison to Other Computer Models

Comparisons were initially made with Chevron's FOAMUP computer program. FOAMUP serves as the current industry standard for foam predictive models, even though it was developed in the early 1970s. The model runs in a mainframe environment. As mentioned, it has been licensed to several service companies.

FOAMUP is based on Bingham plastic fluid rheology, with a set value for fluid yield point. A constant yield point might not be expected to accurately model the rheology of foam fluids because, as the pressure changes at different depths, the foam quality also changes. Changes in foam quality result in changes in fluid viscosity, which should change the yield point of the fluid. Changes in yield point resulting from changs in foam quality can be accounted for in the FOAM computer model if the user selects the Bingham Plastic model. However, Chevron reports that good results have been obtained with their model over the years.

The FOAM computer model includes the option of using the same basic fluid rheology model used by Chevron. FOAM also includes an option to change the initial yield point of the fluid used in the calculations. The Chevron rheology option was used as the basis of comparison between FOAM and FOAMUP.

FOAMUP output was derived from data provided by Chevron. In 1972, Chevron ran extensive laboratory tests for developing their model using a test well. Twenty-three different cases were run to compare FOAM and FOAMUP using data from Chevron's tests.

Figure 3-18 shows that the difference in the surface injection pressures predicted by the two programs ranges from 0.7% to 21.2% for foam qualities of 74 to 100%. Referenced foam qualities were all calculated at the surface in the annulus. The average difference in calculated injection pressure is 8.2%. This level of agreement is acceptable, assuming that one of the models can be demonstrated to be accurate.

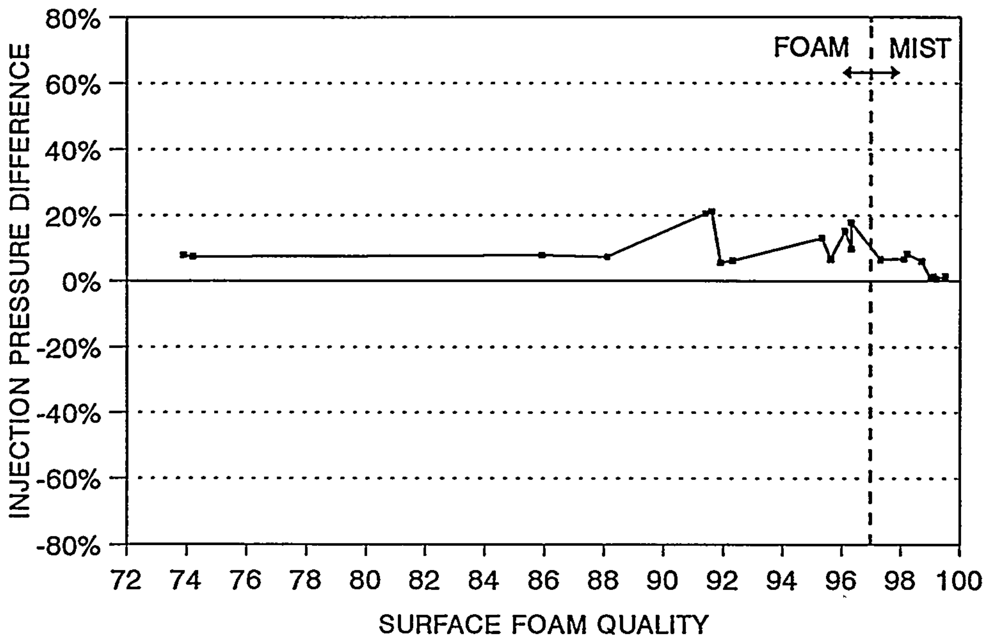

Figure 3-18. Surface Injection Pressures Predicted by FOAM and Chevron's Model

The FOAM program, as currently designed, is based on theoretical assumptions that are valid for true foams only. If foam quality is greater than 96-97%, the calculations are not necessarily valid. However, Figure 3-18 shows that FOAM agrees best with Chevron's FOAMUP at foam qualities of 99% and higher.

Figure 3-19 shows that bottom-hole pressures predicted by the two programs vary between 8 and 20% for foam qualities between 73 and 98%. In the region of high quality that is not true foam, the differences are as much as 50%. The average difference between predicted bottom-hole pressures is 17%.

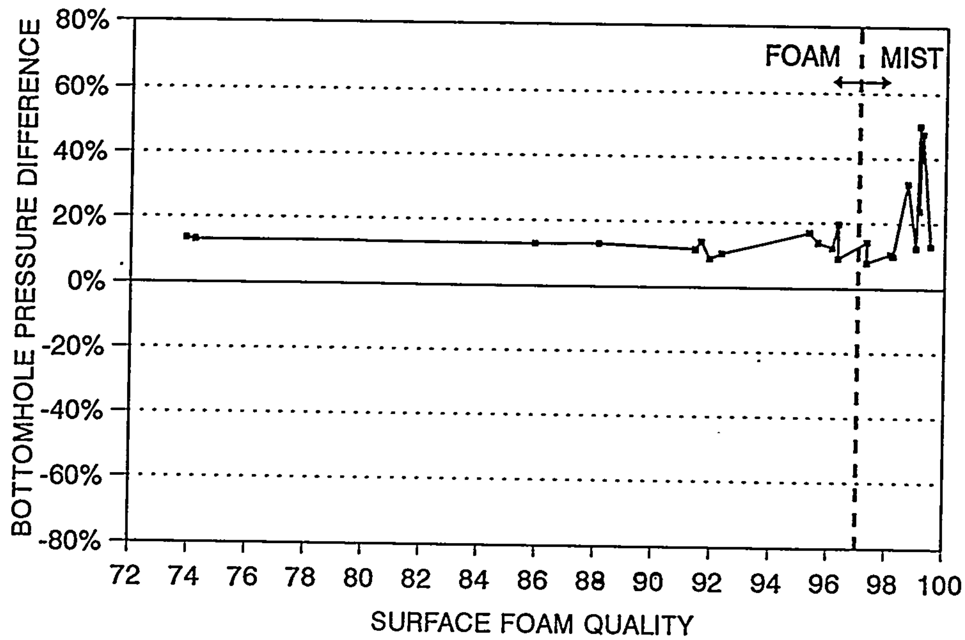

Figure 3-19. Bottom-Hole Pressures Predicted by FOAM and Chevron's Model

A 17% difference in prediction of bottom-hole pressure is probably acceptable at this point of model development. Accurate measurements of actual bottom-hole pressures while drilling with foamed fluids are extremely scarce. Until a variety of accurate measurements are made in the field, one program cannot be said to be more accurate than the other.

The average difference in bottom-hole pressure predictions in the true foam region (i.e. <97% foam quality) is only 9.9%. This level of agreement is acceptable, assuming that either model is capable of accurate pressure prediction, since FOAM is designed just for this application.

Two other models were identified in the available technical literature. The first of these was a Bingham plastic model developed by Krug and Mitchell (1972). The other is a power-law model developed by Okpobiri and Ikoku (1986). Neither of these models is known to be generally available to the industry in any type of PC-based program.

Two other options are included in the FOAM computer model to allow the user to select either Bingham plastic or power-law rheology models. A consensus does not yet exist within the industry concerning the most appropriate rheological model(s) for foam. Various researchers have reported that foam behaves according to one or the other of these models. Others have defined regions of foam quality where the fluid is best described by one or the other of these models. Still others have defined rheological behavior of foams as being bounded by low or high shear rates.

Both types of rheology models have been include in the initial version of FOAM, along with the Chevron rheology option. Field testing scheduled for Phase II will be useful for determining whether all these options should remain in the program or if one model is more accurate than the other.

The Krug/Mitchell and Okpobiri/Ikoku models both fix the foam quality in the annulus at the surface at 96%; therefore, comparisons of FOAM with these models were made for several different depths as well as different combinations of liquid and gas injection and back pressures held on the annulus.

A comparison of FOAM's Bingham-plastic model with the Krug/Mitchell model (Figure 3-20) shows that the difference in predicted surface pressures between the two models ranges from 10.3 to 18.2%. The average difference for the eleven test cases was 13.9%. In every case, the FOAM computer model predicted surface pressures lower than those predicted by the Krug/Mitchell model.

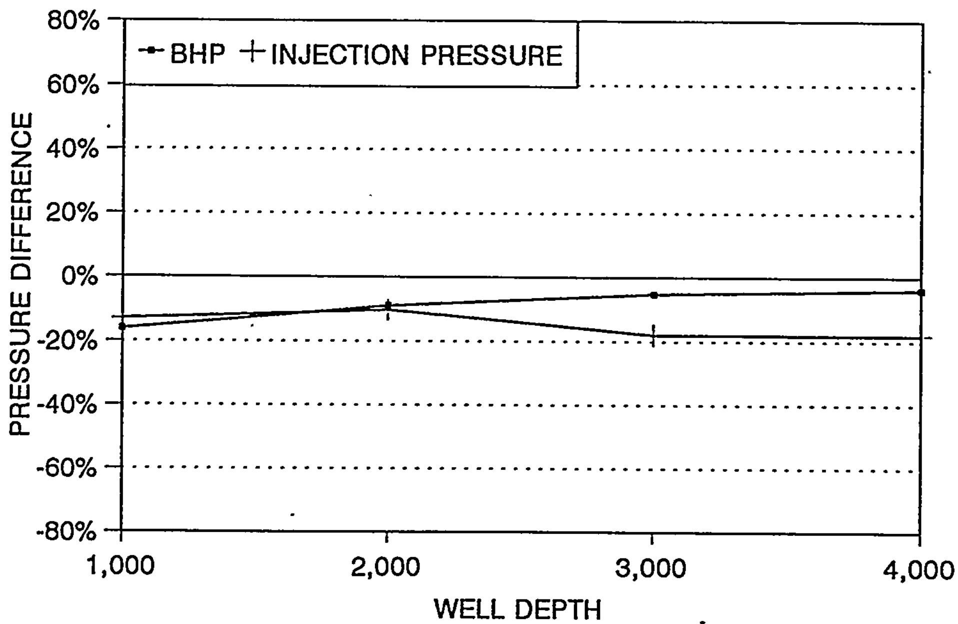

Figure 3-20. Comparison of FOAM and Krug/Mitchell Model

The bottom-hole pressures predicted by the models differed from 4 to 16.2% (see Figure 3-20). The average difference for all eleven cases was 9.5%. Again, all predictions by FOAM were lower than those made by the Krug/Mitchell model. A difference of less than 10% is acceptable, again assuming that one of the models is accurate.

A comparison of results from FOAM's power-law fluid model with the Okpobiri/Ikoku model found the closest agreement of any model considered. Figure 3-21 shows that the differences in surface pressure predictions range from 1.3 to 13.6%. Predicted bottom-hole pressures differed by 8.5 to 18.8% for the cases shown.

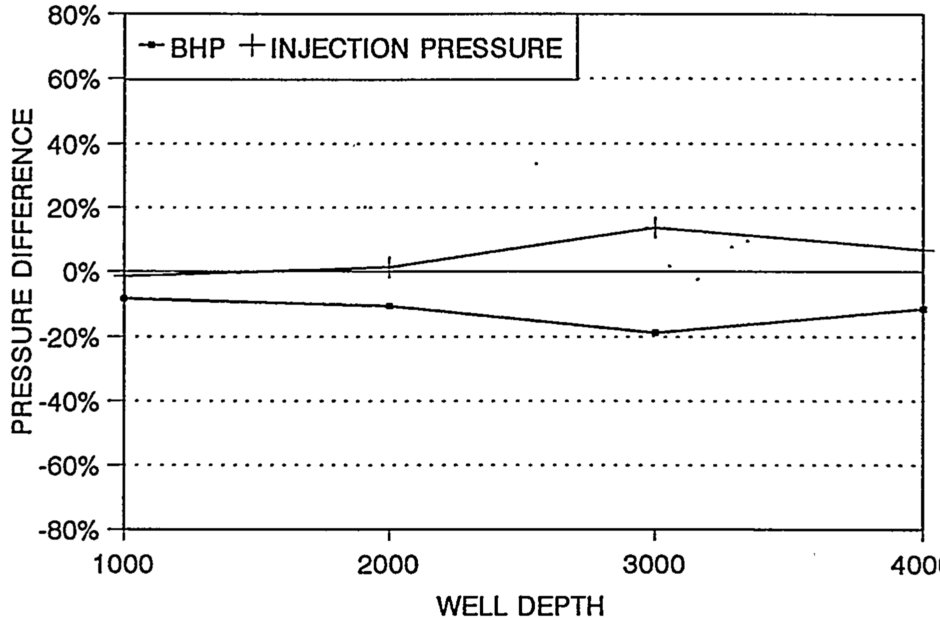

Figure 3-21. Comparison of FOAM and Okpobiri/Ikoku Model

The average difference in surface pressures predicted by FOAM and Okpobiri/Ikoku for all eleven cases run was only 5.2%; the average difference for bottom-hole pressures was 8.6%. Both of these differences indicate acceptable agreement between these models.

FOAM predicted higher surface pressures than did Okpobiri/Ikoku in all but one case. In all cases, FOAM predicted lower bottom-hole pressures. One of the primary uses of FOAM will be to predict required surface pressures in order to size compressors properly. If FOAM's prediction of surface pressure is in actuality higher than the true value, fortunately, any error would be on the conservative side.

A simplified PC-based model for foam fluids was also identified. This model is based on an EXCEL spreadsheet with no graphics and was developed under a Gas Research Institute contract. A copy of this model (called Air/Mist/Foam Model, or AMFM) was also obtained for comparison with the DOE FOAM model.

AMFM was primarily developed to predict pure air and mist operations, although it is currently designed to handle true foams. It has been used in the field to model behavior, and is reportedly 'very accurate,' but no actual data are available for comparison.

Six different hypothetical cases were run using both FOAM (using the Chevron rheology option) and AMFM. Figure 3-22 shows that surface pressures predicted by the models differed by 4.3

to 24.6%, with an average difference of 11.3% on an absolute value basis. Agreement was closest at lower foam qualities.

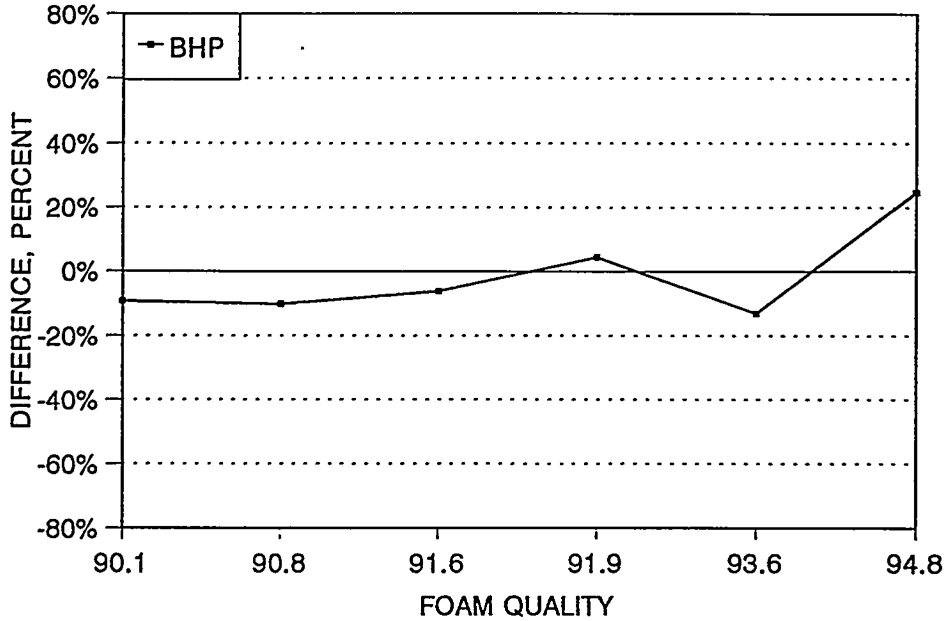

Figure 3-22. Comparison of FOAM and AMFM

3.4.2 Comparison to Laboratory Data

Results made available by Chevron from their 1972 test well measurements were the best source of data used to gauge the accuracy of FOAM. Chevron's test well had a plugged-back total depth of 2904 ft with 9⅝-in. casing from surface to total depth. A string of 2⅞-in. tubing was run to 2809 ft. There were recording pressure gauges installed behind the tubing in the tubing-by-casing annulus at depths of 2809 ft, 1887 ft, and 953 ft.

Air and liquid (i.e., foam) were injected at twenty-three different rates and mixtures, and pressures were recorded by the gauges and at the surface. As described in the previous section, each of these twenty-three data points was used as a comparison between the two programs (FOAM and FOAMUP). Each data point was also used to validate the FOAM model.

Conditions for each of the twenty-three cases were input into the FOAM model. The pressures predicted by the model at each gauge depth and at the surface injection point were all compared to the measured pressures. All results were plotted as a function of foam quality at the surface.

Pressures predicted at the surface matched the measured pressures more closely than at any other location. Figure 3-23 shows the error in the surface pressure predictions made by FOAM ranged from -0.3% to a maximum of 31.8%. The average error was 10.6%.

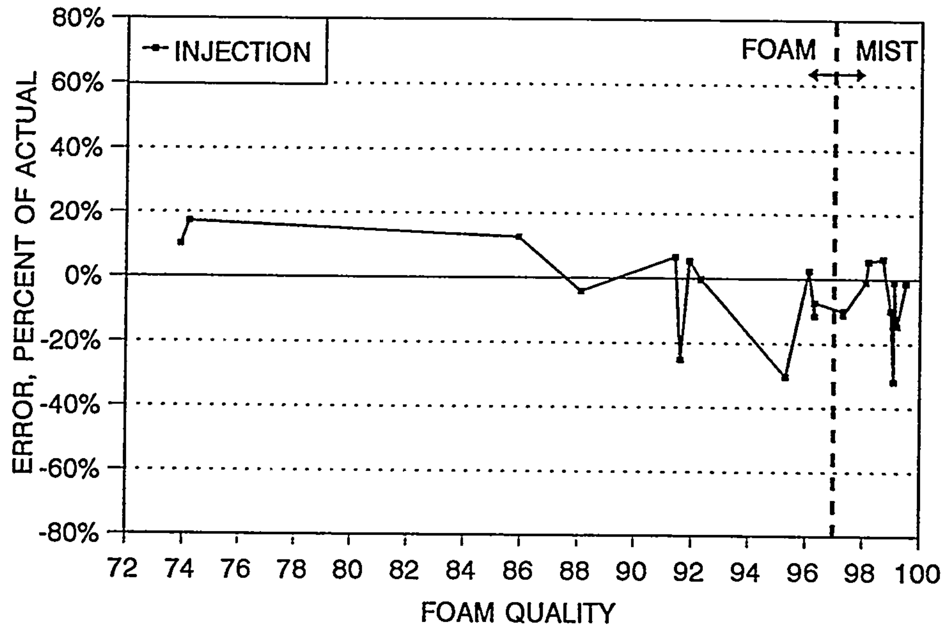

Figure 3-23. Comparison of FOAM to Chevron's Measurements (Surface Pressure)

This level of agreement (10.6%) is an acceptable level of accuracy. The measured data itself may easily have been no more accurate. None of the tests was repeated to gauge repeatability or precision of the measurements.

Like most other oil-field equipment, compressors are designed and manufactured in several standard sizes. If true pressure requirements can be predicted within 10.6%, properly sized equipment can be acquired. Chevron's computer model FOAMUP was calibrated using these data, with an overall average error in predicted injection pressures of 12.1%.

Figure 3-24 shows that the pressures predicted at the bottom of the hole by FOAM were in close agreement with the measurements. Except for one test, the error ranges from 0.4% to 31.4%. For one particular test, pressure predictions made for all depths in the annulus were in error by 55 to 72%. This is true for both FOAM and Chevron's own model. This discrepancy is most likely due to bad data.

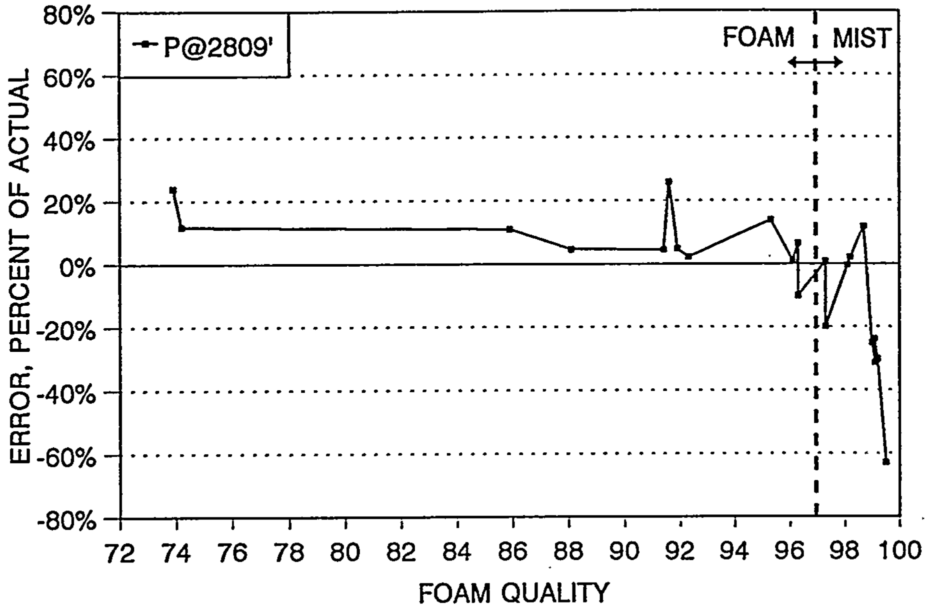

Figure 3-24. Comparison of FOAM to Chevron's Measurements (Bottom-Hole Pressure)

The average disagreement between FOAM and the measurements for bottom-hole pressure is 13.0%. If the suspect data point is removed, the average error is only 10.1%.

The largest errors were observed under conditions that resulted in the foam quality at the surface exceeding 97%. Larger errors are expected under these conditions because these fluids are not true foams. The FOAM computer model is not designed to handle such fluids. The average disagreement within the true foam region is only 10.0%. Again, this is within an acceptable range.

Figures 3-25 and 3-26 show that the absolute error between predictions and actual measurements at other gauge depths in the annulus, 1877 ft and 953 ft, also increased when the foam quality exceeded 97%. Absolute error is defined as the absolute value of the difference in measured pressure and calculated pressure divided by the measured pressure.

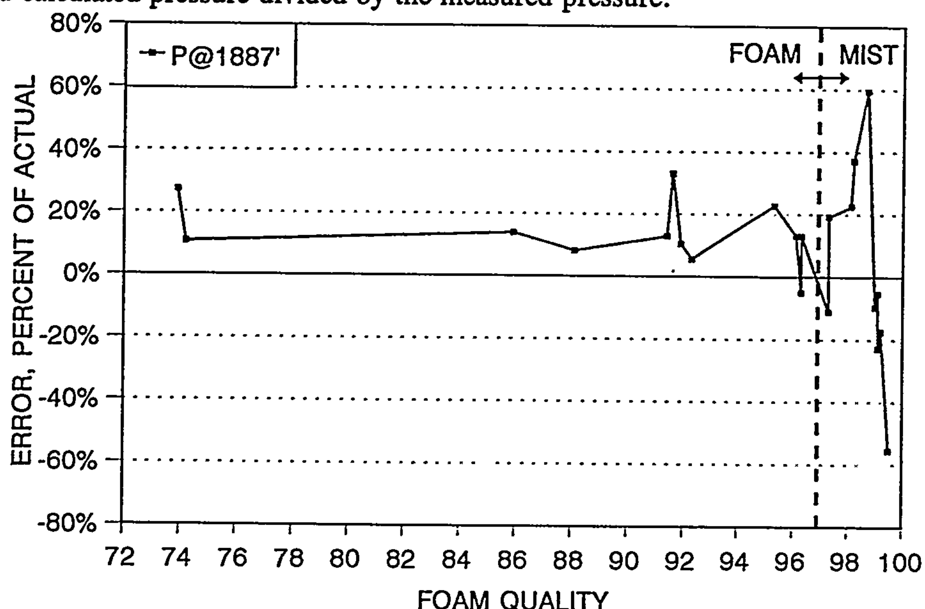

Figure 3-25. Comparison of FOAM to Chevron's Measurements (1887 ft)

The average disagreement for a depth of 1887 ft is 16.3%. When only data points in the true foam region are considered, the average error is reduced to 14.7%.

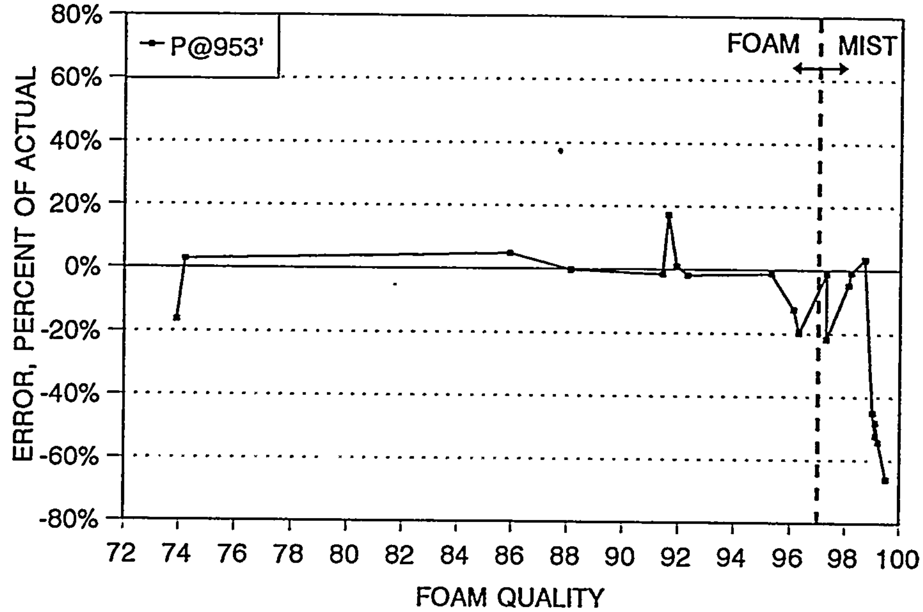

Figure 3-26. Comparison of FOAM to Chevron's Measurements (953 ft)

Pressure predictions made at the shallower depth (953 ft) in the annulus were more accurate. Average disagreement was 11.0%. **When data from the non-foam region are excluded, the average absolute disagreement is only 8.3%.** This is well within an acceptable range.

3.4.3 Comparison to Field Data

Actual measured injection rates and pressure data for foam drilling are very scarce. What data are available consists primarily of injection rates and pressures averaged over 24-hour periods. Depths, lengths of drill string, foam composition and injection pressures can all change dramatically in one 24-hour reporting period, especially when drilling with a lightweight fluid. As much as 1000 ft or more of hole can be made, rendering most 24-hour averages almost meaningless.

To collect field data under specific conditions, Maurer Engineering personnel visited a drilling location while foam drilling was underway. The operation was a horizontal re-entry, and the visit occurred during the kick-off operation. The directional survey tool required a wireline. The wireline prevented the use of floats in the drill string. Every time a connection was made, foam pressure had to be bled off. This slowed drilling operations tremendously.

Accurate data were collected for two separate sets of conditions. One set of data was recorded when the bit was at the kick-off point; another set of measurements was taken when the hole was about 130 ft deeper at an inclination of 28°. At both depths, surface pressure and liquid and gas injection rates were recorded.

Figure 3-27 shows that accuracy of the FOAM program ranged from +3.1% to -4.8%. Foam qualities for the two cases, calculated for a depth of 100 ft in the annulus, were 95.1 and 96.0%, respectively. The most accurate prediction was made at the lower foam quality.

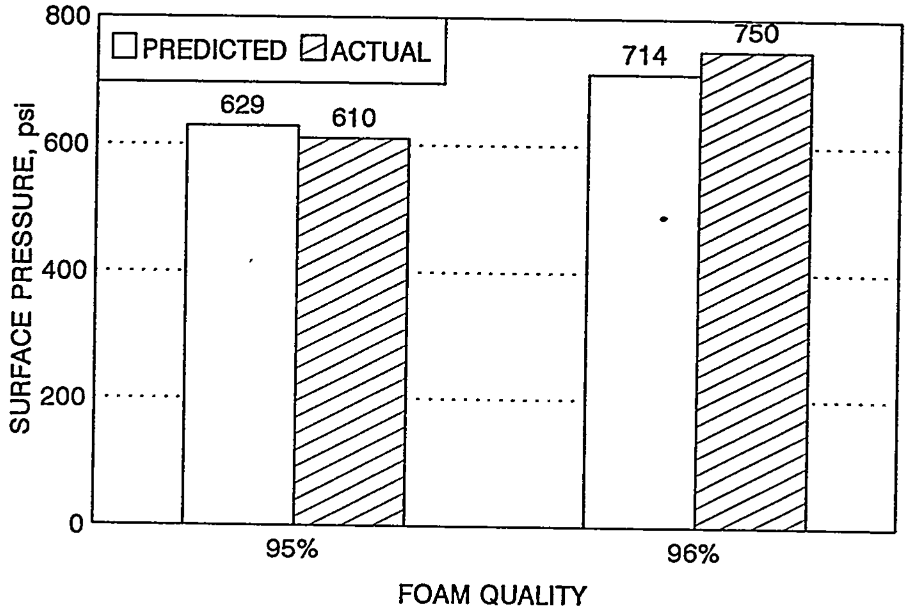

Figure 3-27. Comparison of FOAM to MEI Field Measurements (Injection Pressure)

In the first case, actual injection pressure was 610 psi with 800 scfm of air and 31 gpm of foamer solution. The second data point was measured with an injection pressure of 750 psi with 800 scfm of air and 24 gpm of foamer. The FOAM model predicted injection pressures of 629 psi and 714 psi, respectively, for the two cases.

3.4.4 Conclusions

Results using the FOAM model compared favorably with Chevron's and other published foam models, with average disagreement in prediction of pressures ranging from about 5 to 15%. Close agreement (within 10%) was also found when comparing the FOAM model to Chevron's field data from a test well. The closest match was found between the FOAM predictions and MEI field data recorded on an actual foam drilling operation (<5% error). In almost every case examined in the validation phase, the closest agreement with the FOAM model was in the region where foam quality was less than 97% (i.e., the true foam region). All of these comparisons indicate that FOAM is an effective tool for modeling foam fluids.

For cases where the fluids are not true foams (quality >97%), the program may do a reasonable job of predicting pressures, but errors have the potential to be significantly higher. For operations where the non-foam region extends only a small distance down the annulus, predictions matched measured injection pressures well. FOAM, in its current configuration, will operate with any foam quality.

However, if the foam quality exceeds 97% over more than 500 feet of the annulus, the user is given a warning that the results may not be accurate.

The FOAM model is designed to accurately handle operations in inclined and/or horizontal wellbores with regard to rheological and pressure behavior. Analyzing cuttings transport in horizontal wellbores is beyond the scope of the project.

Any major differences between predictions made by FOAM and those made by other models cannot be resolved until better, more accurate data are evaluated. Unfortunately, those data currently do not reside in the public domain.

Although preliminary validation checks suggest that FOAM is an effective tool for designing foam operations, additional validation should be performed with accurate field data. The final judgment with respect to the overall accuracy of the FOAM program will require the accurate measurement of pressures and flow rates in a variety of actual field operations. Measurements must be made both at the surface and down hole, and both in the drill string and in the annulus. These measurements and further evaluation of the accuracy of FOAM will be performed during Phase II of this project.

4. Development of Lightweight Solid Additives

4.1 BACKGROUND

Drilling underbalanced in underpressured or depleted reservoirs requires fluids lighter than water, that is, with specific gravity (SG) less than 1. Many types of fluid systems can be used, ranging from 100% gas (e.g., air drilling) to 100% liquid. All drilling fluids with densities below 6.9 ppg (SG=0.83) currently being used contain gas or air. In addition to pure gas, these fluids include mist, foam, and aerated (or nitrified) mud.

Even though their use is beneficial for underbalanced drilling, compressible or aerated fluids present several limitations (Figure 4-1).

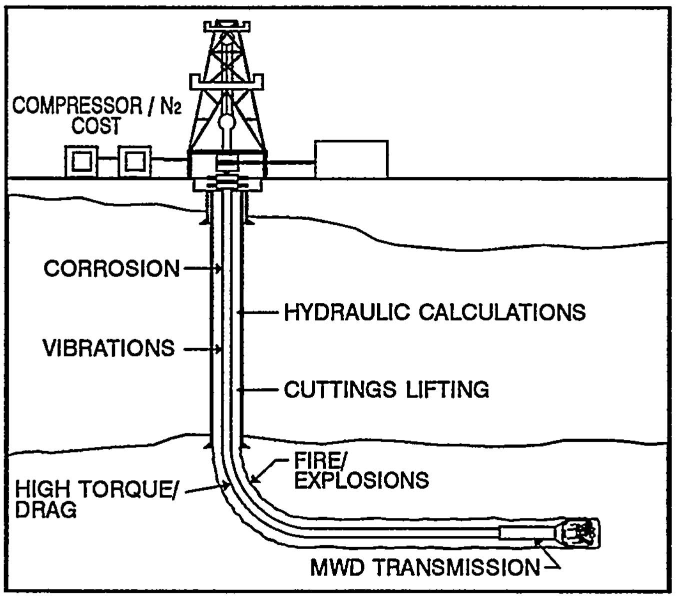

Figure 4-1. Aerated Fluid Problems

Compressors and nitrogen can increase the cost of drilling a well by as much as $20,000-30,000 per day. Drill-string corrosion can be a major problem with aerated fluids, because oxygen is introduced downhole. The presence of oxygen in an environment containing hydrocarbons (e.g., oil or gas) can result in downhole fires and explosions. Hydraulics calculations are also much more difficult due to the compressible, multi-phase nature of the fluid.

Drill-string vibrations are more severe because aerated fluids do not cushion the pipe as well as pure liquids. Air drilling increases torque and drag since the friction factor in an air-filled hole may be as much as 0.5-0.7, compared to 0.2-0.3 in a hole with conventional muds. Cuttings lifting is another major problem in many wells with air and mist drilling. The difficulty in keeping the hole clean can lead to the formation of mud rings, which increases the annular pressure drop and can lead to many other problems such as stuck pipe and downhole fires.

Conventional mud-pulse measurement-while-drilling (MWD) tools will usually not operate in aerated fluids because of rapid signal attenuation in the drill-string fluid. This limitation constitutes a major problem for underbalanced drilling operations in horizontal wells.

A lightweight incompressible fluid, having a density lower than that of water, could overcome most of the limitations associated with aerated fluids, while retaining the significant benefits of underbalanced drilling. In the late 1960s, scientists in Russia used lightweight fluids containing hollow glass spheres to successfully reduce fluid density in areas where severe lost-circulation problems had previously prevented drilling.

Solid spheres have been added to drilling mud in the past to increase lubricity and to lower friction factors. Oil-field service companies in the United States have used hollow spheres and other lightweight additives for years to reduce the density of cements in areas where lost circulation is common. However, as well as can be ascertained, hollow spheres have never been used in lightweight drilling fluids outside of Russia until this DOE project.

4.2 CANDIDATE SELECTION

Commercially available hollow glass spheres (HGS) have typically been used as extenders in paints, glues, and other liquids, besides their uses in the oil and gas industry. They are used as the reflective agent in paints for highway markings and signs. They are also an effective additive in temporary glues, such as those used to make "sticky" note pads, that prevent the contact surfaces from permanently bonding together.

Research into lightweight solids having a specific gravity of less than 1.0 led to the identification of several candidate hollow spheres, including glass, ceramic, and plastic spheres. Final candidate HGS to be used in formulating drilling fluids were selected based on their physical properties and their ability to maintain those properties under the pressure and temperature conditions encountered in oil and gas wells.

The most important properties of HGS are specific gravity and collapse strength. The specific gravity of a sphere is controlled by the ratio of its outer diameter to inner diameter (OD/ID), as shown in Figure 4-2.

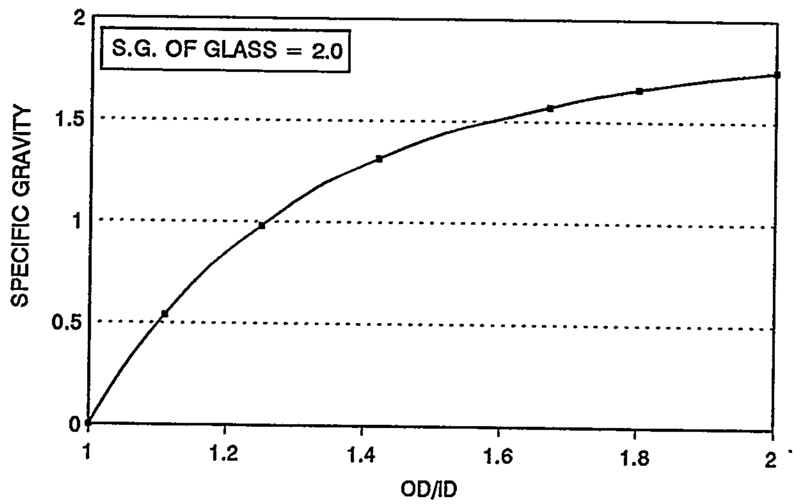

Figure 4-2. Specific Gravity of Glass Spheres

The most critical property other than density is the collapse pressure of the spheres, which is proportional to the cube of the OD/ID ratio (Figure 4-3). To be an effective drilling fluid additive, it is critical that the spheres not collapse at the high fluid pressures existing at the hole bottom of gas wells, since this failure would increase the mud density.

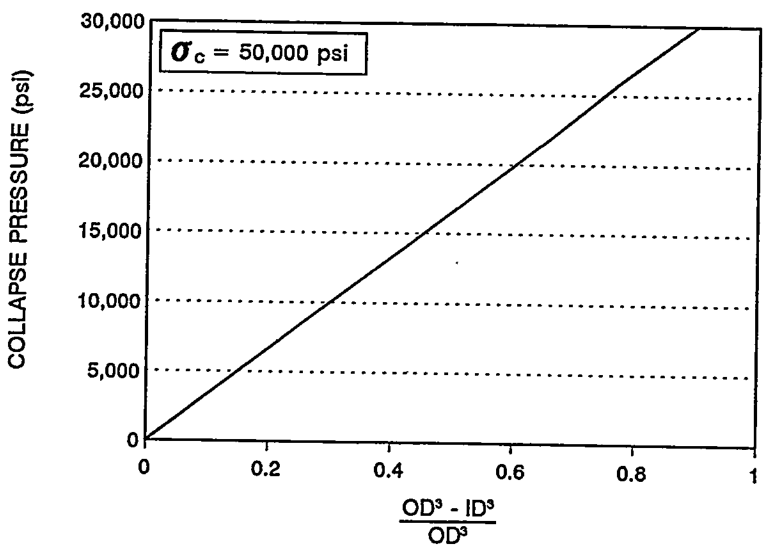

Figure 4-3. Collapse Pressure of Spheres

The collapse pressure at the bottom of the well is a function of the hydrostatic head exerted by the fluid column, as well as the pump pressure. Because the density of lightweight solid additive fluids is lower than conventional fluids, the hydrostatic pressure exerted by the fluid column will be much less than that in a conventionally drilled well. For instance, the hydrostatic pressure at 9000 ft with a mud weight of 8.8 ppg would be 4118 psi. A 6.5-ppg lightweight solid additive fluid (the same 8.8 ppg base fluid with

40% by volume of 0.38 specific gravity hollow spheres) would produce only 3042 psi hydrostatic pressure at the same depth.

Ten candidate hollow spheres showed promise on the basis of published specific gravity and compressive strength data. These spheres were made of plastic as well as glass, and ranged in specific gravity from 0.02 to 0.7. Compressive strengths ranged from 1000 to 10,000 psi.

Friction reducing beads were not considered as candidates for this application because their specific gravity is approximately 1.1, rendering them ineffective in reducing fluid densities to a point below that of water.

Each candidate sphere was mixed with water and placed in a glass container. Their behavior was monitored overnight as a secondary simple screening procedure. The rejection criteria was greater than 10% sphere loss due to settling. Ten percent loss of "floaters" is the manufacturer's specification for most of the candidates. Three of the candidates were rejected on this basis, that is, more than 10% by volume settled to the bottom instead of floating. These candidates were constructed of plastic or sodium borosilicate glass.

Candidate hollow spheres and the results of the settling criteria test are listed in Table 4-1. No rigorous determination was made of the cause of failures, which may have been due to permeability or solubility of the spheres.

TABLE 4-1. Candidate Hollow Glass Spheres

PRODUCT	CHEMICAL COMPOSITION	SPECIFIC GRAVITY (g/cc)	COMPRESSIVE STRENGTH (psi)	% SETTLED IN WATER	REMARKS
Spherelite	Volcanic Ash	0.7	6000	< 5	Relative high specific gravity
BJO-0840	Plastic Hollow Spheres	0.35	1000	100	Soluble in Water
Q-Cel 640	Borosilicate (Silicic Acid)	0.42	2000	100	Soluble in Water
Q-Cel 650	Borosilicate (Silicic Acid)	0.48	3000	100	Soluble in Water
PM-7228	Borosilicate Glass	0.28	1000	< 5	Insoluble in water; limited compressive strength; & expensive ($12.85/lb)
PM-6545	Polyacrylonitrile (Mixed Polymers)	0.02	2000	<5	Insoluble in water; limited compressive strength; & very expensive ($22/lb)
SDT-40	Borosilicate (Eccospheres)	0.4	4000	5	Slightly soluble in water & very expensive ($57/lb)
B-38	Soda-Lime Borosilicate Glass	0.38	4000	< 5	Insoluble in water; high compressive strength
K-37	Soda-Lime Borosilicate Glass	0.37	3000	<5	Insoluble in water
S-60	Soda-Lime Borosilicate Glass	0.6	10,000	<5	Insoluble in water, very high compressive strength

The final criteria for laboratory candidate selection was cost. Several of the spheres performed well and were acceptable with respect to specific gravity and collapse pressure, but were very expensive (as much as $57/lb). The candidates selected for further laboratory testing cost between $1.85 to $2.00/lb. A drilling fluid composed of even 40% by volume of these spheres would have a cost comparable to that of an oil-base mud, which was considered an upper limit for economic feasibility of this type of fluid.

The initial candidates included lightweight additives familiar to the industry such as the crystalline-silica (commonly called Spherelite™), which is routinely used in lightweight cements. Hollow glass spheres with specific gravities of 0.7 are adequate for cementing applications since they significantly reduce the density of cement slurries that have specific gravities of 1.8 to 2.0. Unfortunately, these particular spheres have a minimal impact on the density of muds having specific gravities of 1.03-1.05.

Consequently, low-density spheres (i.e., SG=0.35-0.40) are required for effectively reducing fluid density for underbalanced drilling. For example, the addition of 50% Spherelite™ by volume (SG=0.7) would reduce the density of 8.5 ppg mud to only 7.7 ppg. This would not be adequate for most underbalanced drilling applications. The same argument can be made for S-60 spheres (see Table 4-1). Even though its compressive strength is very high, the specific gravity is relatively high, reducing its usefulness for lightweight drilling muds.

Microscopic hollow glass spheres with specific gravities of 0.37-0.38 and collapse pressures of 3000-4000 psi were the candidates chosen for extended testing as an additive for lightweight drilling fluids. These products are manufactured by 3M, and are designated K-37 and B-38 (see Table 4-1). They are ideally suited for this application because of their low density (Figure 4-4) and acceptable collapse pressures.

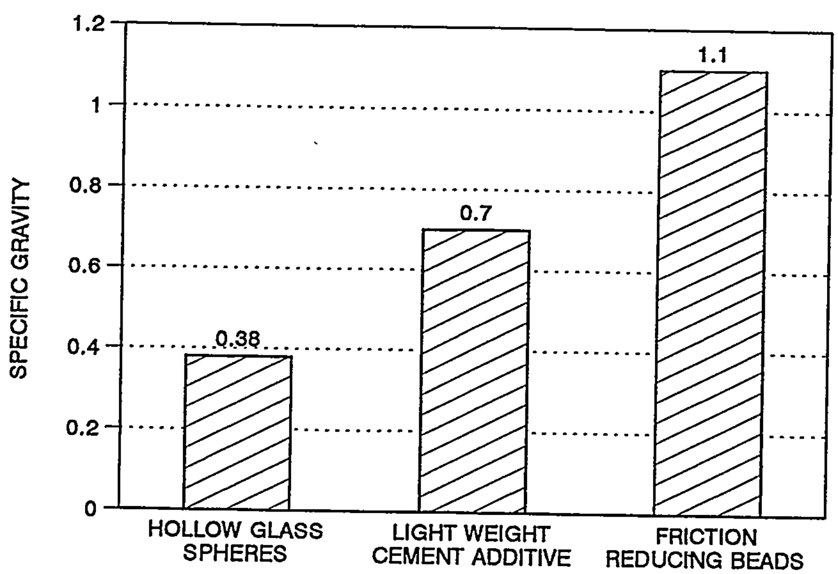

Figure 4-4. Specific Gravity of Spherical Additives

The glass spheres selected for testing as additives for lightweight drilling fluid have properties similar to those used by the Russians in the early 1970s (Table 4-2). This activity was described previously.

TABLE 4-2. Properties of Lightweight Hollow Spheres

	RUSSIAN	U.S.A. MANUFACTURE
Material	Glass	Glass
Specific Gravity	0.35–0.40	0.34–0.41
Average Diameter, Microns	50–70	40–60
Collapse Strength, psi	2500–3600	3000–4000

A 50% concentration of these 3M hollow glass spheres (SG=0.38) decreases the density of water from 8.3 ppg to 5.8 ppg (Figure 4-5), which is sufficient for many field applications. The density of diesel oil-base mud can be reduced from 7.0 ppg to 5.1 ppg with the same concentration of these hollow glass spheres.

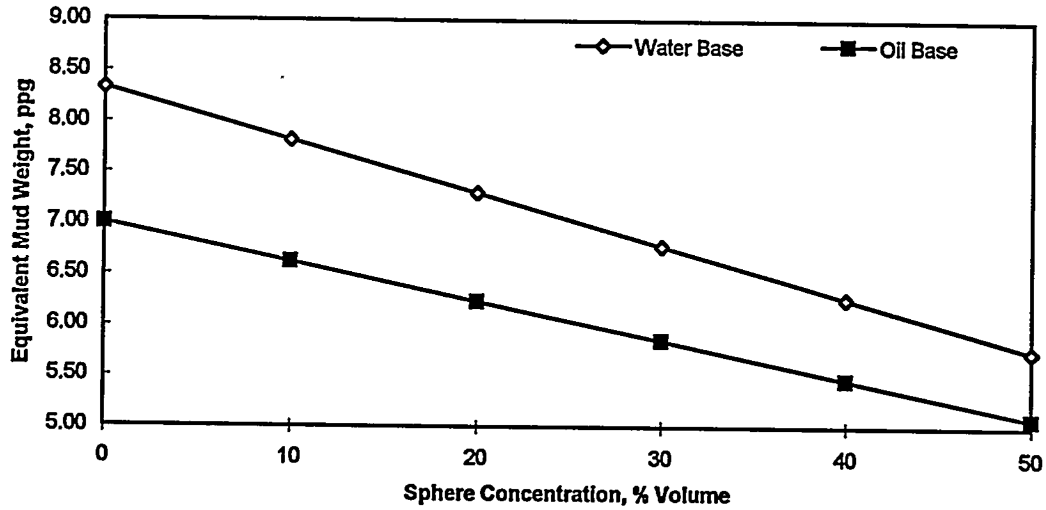

Figure 4-5. Mud Weights with Glass Spheres

4.3 LABORATORY TESTING

The two commercially available hollow glass spheres (HGS) identified as the best candidates were subjected to laboratory and yard testing. A Phase I test plan was developed that includes laboratory and yard testing of drilling muds containing HGS. The laboratory tests included standard API drilling fluid tests such as density, filtration loss, and rheology of fluids composed of various concentrations of HGS in water-base and oil-base muds.

Phase I yard testing investigated the effectiveness of existing solids-handling equipment on HGS fluids with regard to both damage and recovery of spheres. Modifications to existing solids-control equipment were carried out as required.

4.3.1 Verification of Properties

The two most important properties of the spheres are specific gravity and collapse strength. Specific gravity is the most easily confirmed property. The candidate spheres theoretically provide fluid densities like those described above. The most direct method to measure specific gravity is to mix a known weight of the product with water and measure the displaced fluid to find the volume occupied by the spheres. Specific gravity is then a simple calculation.

This procedure is less effective when measuring lightweight solids, however, because the spheres float and do not completely displace the water. To quickly confirm the specific gravity of the candidates, a known weight of spheres was mixed with a drilling mud of known density and volume. By then measuring the volume and density of the new mixture, the specific gravity could be inferred.

Figure 4-6 shows that the density of HGS fluid decreases from 8.8 to 6.0 ppg as the HGS concentration is increased from 0 to 50%. This confirmed that the specific gravity of B-38 spheres is 0.38.

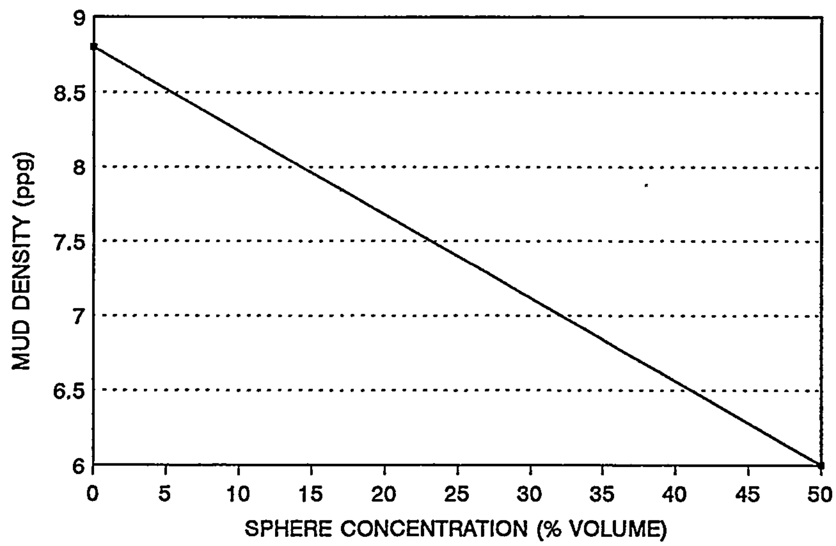

Figure 4-6. Determination of Sphere Specific Gravity

Collapse tests were performed on the four lowest-cost candidate hollow sphere additives that passed the settling test. The spheres were mixed with water and placed in a pressure test cell, as shown in Figure 4-7. The percentage of "sinkers" was measured first with no pressure applied and then after 2000 psi was applied to the fluid for 24 hours. The 2000-psi criterion was selected based on anticipated maximum pump pressures and hydrostatically imposed pressures required for field use. Collapse test results are summarized in Table 4-3.

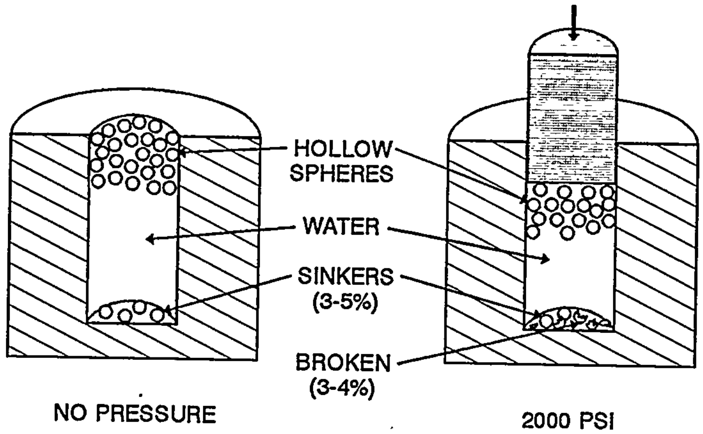

Figure 4-7. Collapse Pressure Tests

TABLE 4-3. Collapse Pressure Test Results

Sphere Identity	Material	Average Specific Gravity (Water=1.0)	Advertised Compressive Strength, psi	Percent "Sinkers" (24 hr)
B-38	Glass	0.38	4000	5
K-37	Glass	0.37	3000	8
PM6545	Plastic	0.02	2000	15
PM7228	Glass	0.28	2000	20

The two candidate spheres with the lowest specific gravities were rejected on the basis of these tests. Cost considerations also supported the rejection of these two candidates since they were among the most expensive candidates tested.

One objective of the project was to develop a lightweight fluid that is incompressible. The compressibility of the proposed fluids was tested using the same apparatus. The sphere/water mixture was placed in the test cell and subjected to a pressure of 2400 psi. The pressure was held for 24 hours.

When the pressure was released, the fluids were examined for sphere breakage. Three to five percent (by volume) of the HGS broke and sank after being subjected to a pressure of 2400 psi. These results were considered to be within acceptable limits. An initial compressibility factor for the fluid was calculated on the basis of change in volume per psi. The first pressurization yielded a compressibility factor of 5.3×10^{-6} psi^{-1}.

The samples were then repressured to 2400 psi. No additional sphere breakage was apparent. As a consequence, the compressibility was less than for the first test. Figure 4-8 shows the slight decrease in volume of the mixture as the pressure increased. The compressibility of the HGS/water mixture for the second test was 3.2×10^{-6} psi^{-1}. This is quite comparable to the compressibility of pure water, measured in the test apparatus as 3.4×10^{-6} psi^{-1} . These results indicate that these glass spheres (and the HGS fluid) are essentially incompressible.

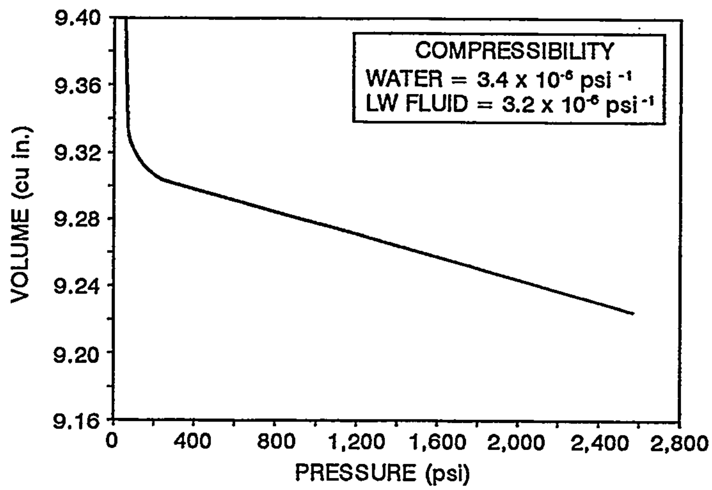

Figure 4-8. Lightweight Fluid Compressibility

Additional collapse-pressure tests were performed on the B-38 fluid by the Chevron Drilling Technology Center (DTC) with pressures up to 4300 psi at room temperature and at 250°F. The average compressibility was 4.8×10^{-6} psi^{-1} at room temperature and 4.0×10^{-6} psi^{-1} at 250°F, again showing that these spheres are essentially incompressible.

The size of the spheres is also an important parameter with regard to recovery from a drilling fluid. Size can also impact rheology, in that many small particles tend to cause a fluid to have higher viscosity than would fewer large particles having the same weight and overall volume. In general, this is a function of surface area available for chemical reaction within the fluid. The specific relationship for HGS surface area in mud was beyond the scope of this project.

The particle size distribution of a random sample of K-37 spheres is shown in Figure 4-9. This distribution was measured at the Chevron DTC using a Microtrac Particle Size Analyzer. The spheres were measured in water and, as a check, in isopropyl alcohol. Average particle size is 47-48 microns.

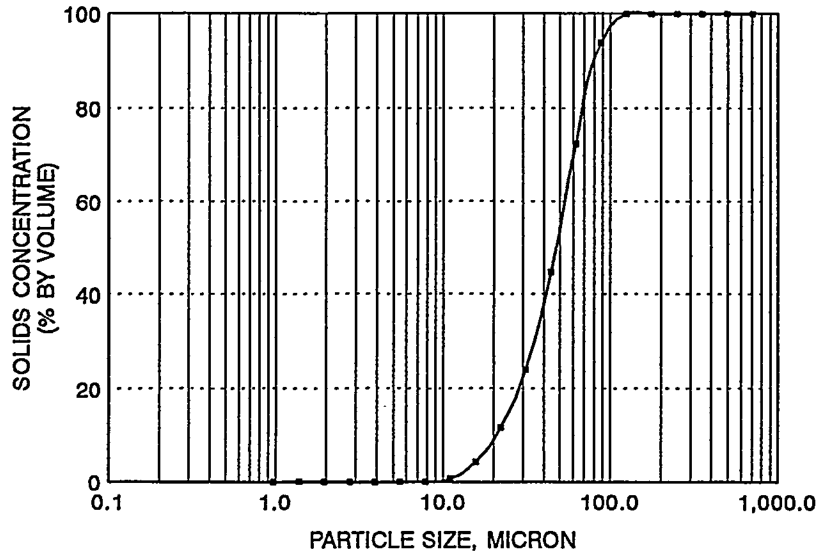

Figure 4-9. Particle Size Distribution of Hollow Glass Spheres

Sphere size can be compared to other solids likely to be encountered in drilling. Typical drill cuttings are in the range of 500 microns. Sand is usually considered to be from 74-500 microns; silt ranges from 2 to 74 microns, and clay is generally considered to be anything smaller than 2 microns. Barite particles are about the same size as silt, while dispersed bentonite particles are in the range of clay.

4.3.2 Basic Rheology

Rheology of a fluid is primarily a description of the fluid's viscosity and flow behavior. The addition of solids to any fluid changes the rheology. These changes may be positive or negative, depending on the desired characteristics. In general, greater solids content leads to increased viscosity and greater resistance to flow.

Solids such as bentonite and barite are intentionally added to conventional fluids to affect the viscosity or density (i.e., mud "weight"). Hollow glass spheres can be added to drilling muds to affect the same parameters. Like conventional solids, lightweight additives increase the viscosity as solids concentration increases. Unlike conventional solids, however, increasing concentrations of lightweight additives actually decrease the mud weight.

Every solid has a minimum water requirement for mixing with a fluid. Below the minimum requirement, the mixture ceases to behave as a fluid. For the B-38 spheres, this requirement was determined to be between 45 to 40% water in the mixture. Additions of solid material to a volume ratio greater than 55% increased the viscosity to the point where the mixture was no longer fluid.

The solids content of a mud in field operations increases as drill cuttings are added. This dehydrates the mud. Even a typical "low-solids" mud carries 4-8% drill solids. Therefore, a practical limit for hollow-glass sphere concentration in a drilling fluid is 35-40% by volume (i.e., 6.5 to 6.8 ppg). All additional laboratory tests were done with fluids having this concentration of spheres or less.

Mudtech, the mud laboratory that performed most of the rheological tests, followed conventional well-site and mud laboratory procedures. All concentrations of lightweight solid additives were reported in terms of pounds per barrel (ppb). In most cases, the data are reported in this report in both ppb and in percentage by volume. Most tests were run with concentrations of HGS ranging from 0 to 90 ppb (0 to 40% by volume).

According to the manufacturer of the two selected candidates, K-37 and B-38, these products behave rheologically similarly because they are made of the same basic material. Most tests were run with either K-37 or with B-38 spheres to make the most efficient use of project funds allocated for testing. The sphere type used is specified, however, for each test description.

4.3.2.1 Fresh-Water Muds

Polymer fluids have been used in nearly every major drilling region in the United States. Partially Hydrolyzed Polyacrylate (PHPA) muds were selected for initial testing because they are used routinely in regions where underbalanced drilling is applied. Water-base PHPA mud systems containing up to 40% by volume of HGS (approximately 90 lb/bbl) were tested in the laboratory.

The base-case mud used for the series of tests using fresh-water mud was composed of water, 10 ppb of bentonite (viscosity control), 25 ppb of REV dust (simulated drill solids), 0.5 ppb PHPA (viscosity control), 0.5 ppb PAC (filtration loss control), and various amounts of B-38 HGS.

The effects of HGS concentration on rheology and API filtration rate were measured before and after hot rolling for 16 hours at 150°F using standard API test procedures and equipment. Standard API tests are usually performed at 120°F. The hot rolling was done to simulate the circulating temperature of a well about 9500 ft deep. The rheology was measured using a Fann 35A viscometer.

The rheology of HGS fluid is similar to that of conventional drilling fluids (Figure 4-10). Plastic viscosity (PV) is normally directly related to the concentration of solids in the mud. The HGS fluid's PV increases with solids content. The PV is 60 cp at a sphere concentration of 40%, which is relatively high but is within acceptable limits for a drilling fluid. A conventional fluid having a 40% solids content would very likely have a similarly high PV.

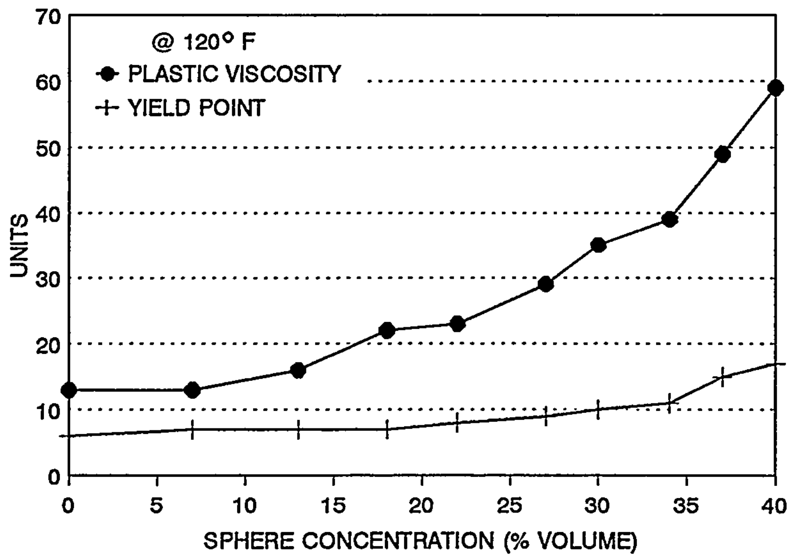

Figure 4-10. Lightweight HGS Fluid Rheology

Yield Point (YP) is an indirect measure of the fluid's capacity to suspend and carry cuttings. Figure 4-10 shows that the YP increased, but remained within acceptable limits, as the solids concentration was increased to 40%. The increase in YP was not as dramatic as the increase in PV. This indicates that the solids being added provide some additional carrying capacity to the mud, although relatively little.

Figures 4-11 shows that the PV of the HGS fluid hot-rolled for 16 hours at 150°F was slightly lower than at 120°F. This is not uncommon behavior for a conventional drilling mud. The addition of heat tends to thin the mud slightly, thereby reducing the viscosity. Very high temperatures may tend to dehydrate the mud, which can cause problems with increased viscosity and gel strength. This problem is discussed in greater detail below. However, HGS muds should be suited for the typical medium-depth well targeted by the project.

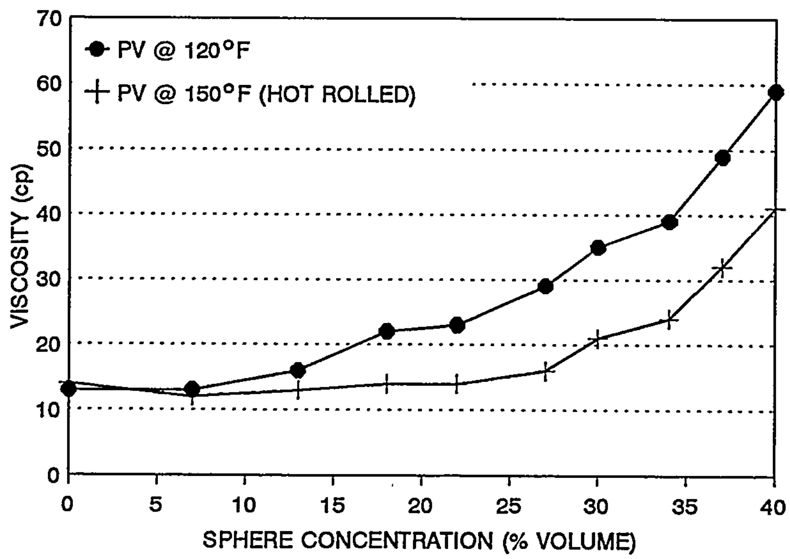

Figure 4-11. PHPA/HGS Plastic Viscosity

The YP of the HGS fluid decreased when it was hot-rolled for 16 hours at 150°F (Figure 4-12). This decrease was not as pronounced as that of the PV. This may indicate that the fluid can maintain its carrying capacity even though thinned by high temperature.

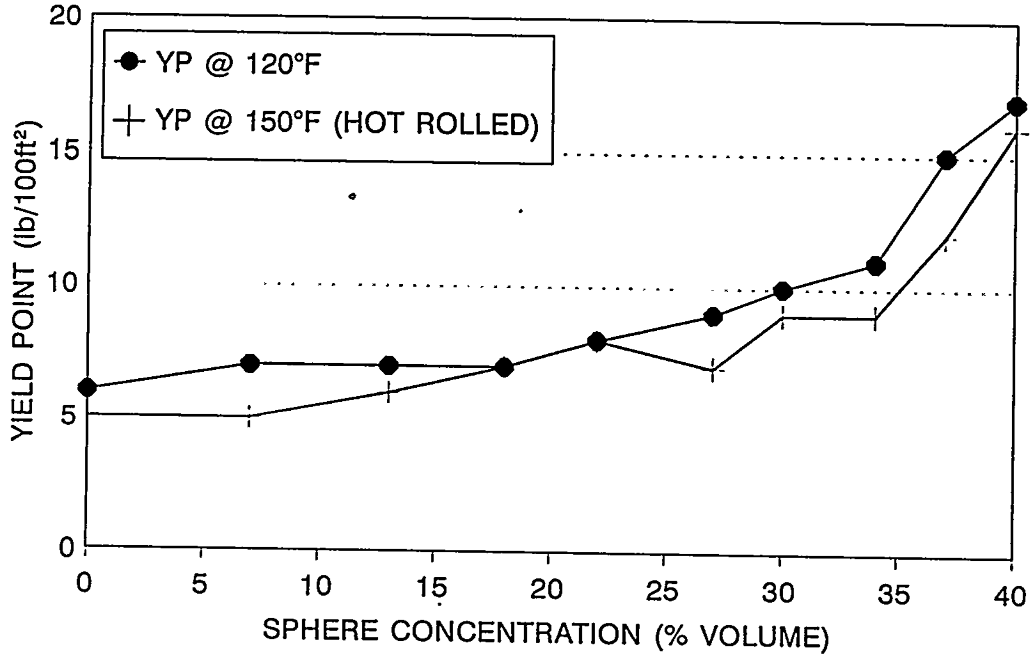

Figure 4-12. PHPA/HGS Yield Point

API filtration loss is an indication of the relative amount of filtrate that may be lost to permeable formations downhole while drilling. Filtration loss can either increase or decrease with increasing solids concentrations, depending on the type of solids present and the chemical reactivity of the solids with other mud components.

Generally, a mud with a controlled filtration loss would lose 15-25 cc/30 min of filtrate during a standard API filter-loss test. A mud with less than 10 cc/30 min of filtration loss is considered to be a low filtration loss mud. PHPA muds normally have filtration losses measured below 20 cc/30 min; often it is even lower.

Figure 4-13 shows that the API filtration loss for the PHPA/HGS mud decreased from 8.3 to 6.0 cc/30 min as the sphere concentration was increased from 0 to 25%. As the sphere concentration was further increased to 40%, fluid loss increased slightly to 6.5 cc/30 min. This slight increase is negligible, and can be explained in terms unrelated to the HGS concentration. The PHPA mud tested contained 0.5 ppb of a polyacrylate (PAC) fluid-loss control agent commonly found in PHPA muds. These filtration losses are similar to conventional PHPA muds and are within acceptable limits.

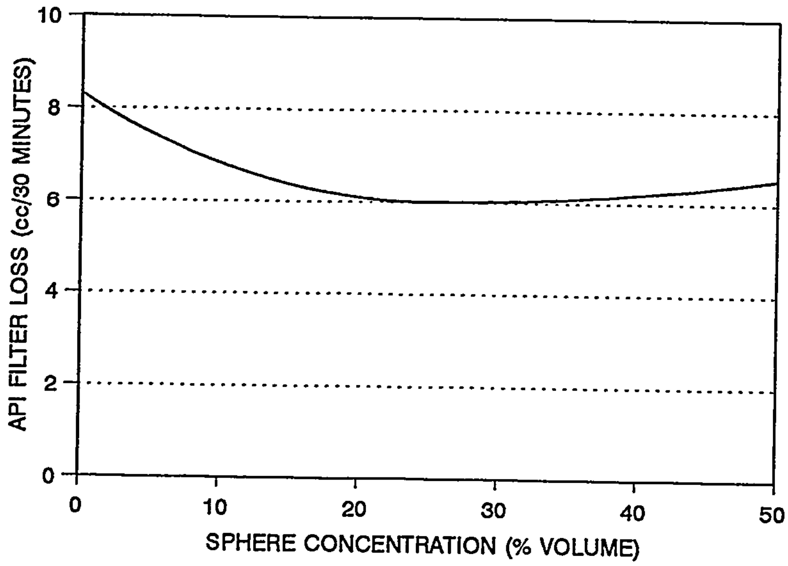

Figure 4-13. PHPA/HGS API Filter Loss

Table 4-4 compares the properties of a conventional PHPA drilling fluid to an HGS drilling fluid containing 40% HGS by volume.

TABLE 4-4. Properties of PHPA Muds

	Conventional PHPA Mud	HGS PHPA Mud
Mud Weight, ppg	8.8	6.6
Plastic Viscosity, cp	13	59
Yield Point, lb/100 ft^2	6	17
Initial Gel, lb/100	3	4
10 Min., Gel, lb/100 ft^2	3	6
Percent Solids	4	42

4.3.2.2 Oil-Base Muds

A diesel oil-base mud system containing up to 40% HGS by volume (90 ppb) was also tested in the laboratory. Oil-base muds are normally considered lightweight fluids because their density is less than that of water. They are often used to prevent formation damage in areas where formations are sensitive to water. The addition of lightweight solid additives to oil-base mud will decrease the density even further, expanding the application of oil-base muds in underbalanced drilling.

The effects of HGS additions on rheology and API filtration rate were measured before and after hot rolling for 16 hours at 150°F using standard API test procedures and equipment. Rheology was measured using a Fann 35A viscometer. The base mud used in all oil mud testing was composed of diesel oil and water in a 70/30 ratio, 8 ppb primary emulsifier, 2 ppb secondary emulsifier, 4 ppb lime, 2 ppb organophylic clay, 8 ppb Amine Lignite, 35 ppb $CaCl_2$ (75,000 ppm chlorides and 35,000 ppm calcium), and various concentrations of K-37 HGS.

The basic rheology of oil-base mud changes as the lightweight solid additives are added. Figure 4-14 shows that the plastic viscosity (PV) increases from 12 to 122 cp as the sphere concentration increases from 0 to 90 ppb (40% by volume). The most dramatic increase occurs after the concentration surpasses 50 ppb (26% by volume).

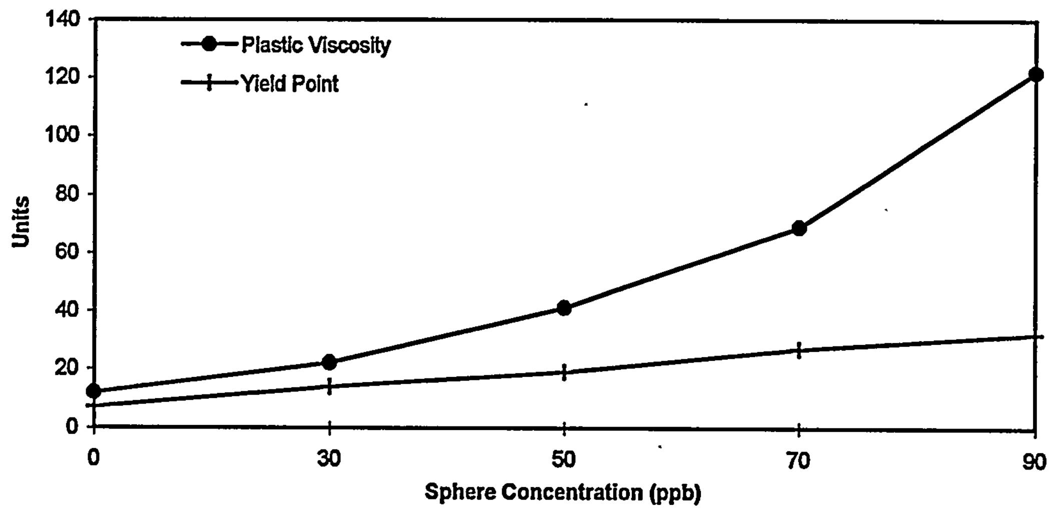

Figure 4-14. Oil-Base HGS Mud Rheology

A PV of near 60, reached at a sphere concentration of about 60 ppb, probably represents the practical limit for field use of HGS in oil-base mud. The mud weight at this concentration is 6.15 ppg. This is less than the limiting case for fresh water-base muds, which is about 6.6 ppg at the practical limit of 40% by volume HGS (90 ppb).

Like the fresh-water PHPA mud described in the previous section, the yield point for the oil-base mud remains relatively flat as the HGS concentration is increased to 90 ppb (see Figure 4-14). The slope of the YP curve changes once the concentration of spheres reaches 50 ppb, again indicating a possible practical limit.

A hot roll temperature of 150°F is not high enough to damage a conventional oil-base mud. Hot rolling the HGS oil-base mud for 16 hours had no significant effect on either the PV or the YP, as shown in Figures 4-15 and 4-16. Oil-base mud is typically not as significantly affected by increasing temperature as is PHPA mud.

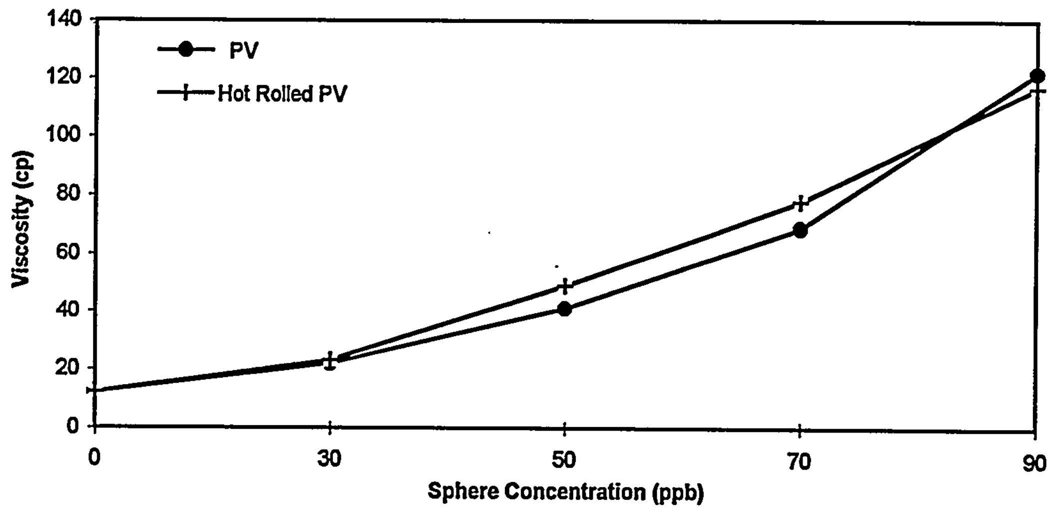

Figure 4-15. Oil-Base HGS Mud Plastic Viscosity

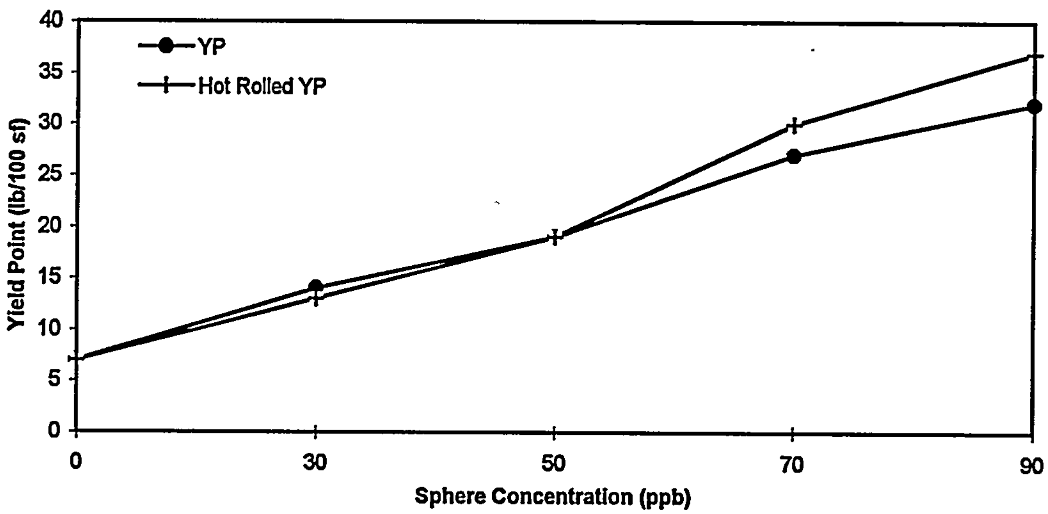

Figure 4-16. Oil-Base HGS Mud Yield Point

Another parameter used to detect deleterious changes in the condition of an oil-base mud is the electrical stability or emulsion stability (ES). ES was measured for each test sample using standard API methods and a Baroid Model 23D meter. In general, the higher the ES, the tighter the fluid emulsion. As the emulsion relaxes, the ES reading decreases. A rapid or significant drop in the ES may indicate that the oil/water emulsion is breaking down .

Figure 4-17 shows that the electrical stability decreased from 776 volts to 445 volts as the sphere concentration was increased to 90 ppb. ES normally increases with increasing solids content for oil-base muds. A good rule-of-thumb is to monitor the ES more closely if it drops below 400, although good emulsions can exist below that point. A sphere concentration of up to 90 ppb did not damage the mud from the standpoint of emulsion stability.

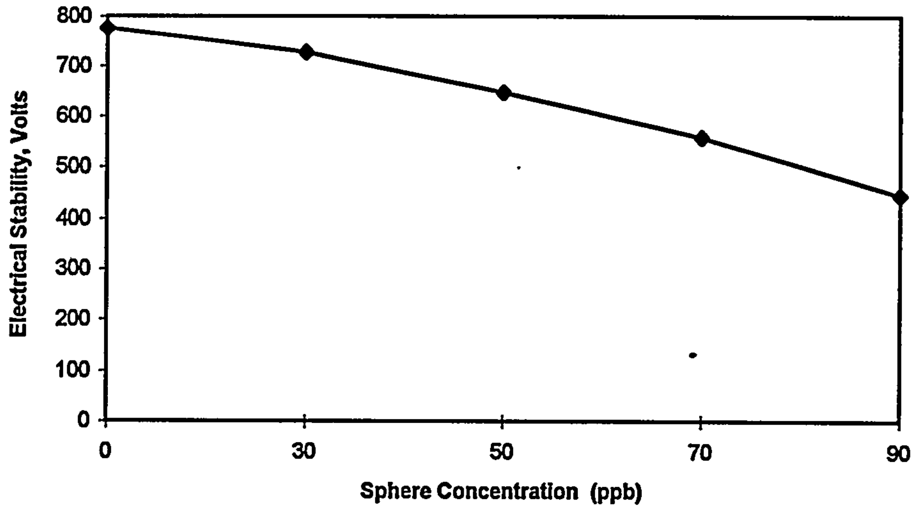

Figure 4-17. Oil-Base HGS Mud Electrical Stability

The high-temperature/high-pressure (HTHP) filtration loss (FL) was also measured on each oil mud sample at 275°F. Neither the initial HTHP FL nor the hot rolled sample HTHP FL changed significantly as the HGS concentration was increased to 90 ppb. Initial HTHP filtration loss increased from 1.8 cc/30 min to 2.2 cc/30 min. Hot-rolled sample HTHP filtration loss increased from 3.6 to 4.2 cc/30 min.

4.3.2.3 Salt-Water Muds

Salt-water muds are used in many drilling provinces throughout the United States, but their primary application is offshore. Because of the high densities inherent in salt-water muds (e.g., saturated NaCl water weighs 10 ppg), they are rarely used in underbalanced drilling. In the Austin Chalk formation of central Texas, salt water of varying composition has been used in underbalanced drilling of overpressured reservoirs.

Since these reservoirs can be drilled underbalanced without lightweight fluids, lightweight solid additives such as HGS have very limited applicability in salt-water muds. An exception would be a situation where an operator wants to drill with as light a mud weight as possible, as well as use a non-damaging salt-water-base fluid as the drilling medium.

To account for this possibility, samples of fresh-water mud with up to 3% potassium chloride (KCl) were tested with 50 ppb (26% by volume) of hollow glass spheres. The KC1 had the same general effects on the HGS mud as it typically has on conventional muds. Both the viscosity and the filtration loss increased as the concentration of KC1 was increased.

The plastic viscosity increased from 8 to 12 cp and the API filtration loss increased from 39 to 62 cc/30 min as the concentration of KC1 increased from 0 to 3 percent. KC1 is most frequently used at concentrations of 3% or less. These concentrations should not cause a problem with the HGS mud. Higher concentrations of KC1 should be pilot tested before use with the spheres.

4.3.3 Effect of Contaminants

Tests were conducted to determine the effects of drill solids on the performance of both water-base PHPA and oil-base HGS fluids. Contamination of oil-base HGS mud by fresh and brine water was also studied. Water has a greater impact on the performance of oil-base muds than it does on water-base muds.

Water-Base Mud Contamination

During two series of tests on fresh-water PHPA fluid, HGS concentration was held constant at 30 and 50 lb/bbl (16 and 26% by volume) while the concentration of drill solids (REV dust) was increased from 0 to 90 ppb (approximately 0 to 10% by volume). Results reported below are for a sphere concentration of 50 ppb. Trends were similar for the 30-ppb sphere concentration, although initial and final values were slightly lower.

Figure 4-18 shows that the PV (plastic viscosity) increased from 20 to 63 cp while the REV dust concentration was increased to 90 lb/bbl at 120°F. Hot rolling the mud at 150°F for 16 hours reduced the PV slightly at low drill solids concentrations. At higher drill solids concentrations (i.e., over 80 ppb), hot rolling significantly increased the PV.

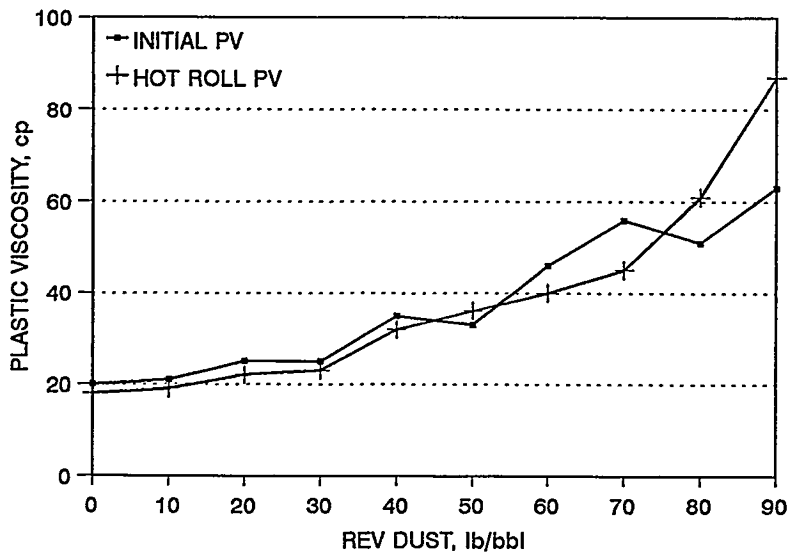

Figure 4-18. Effect of Drill Solids on PHPA HGS Mud (PV)

Figure 4-19 shows that at high solids concentrations, hot rolling decreased the YP (yield point), while at low solids concentrations the YP was virtually unaffected. As the simulated drill-solids content rose from 0 to 90 ppb, the YP increased from an acceptable 8-9 up to over 40 lb/100 ft^2.

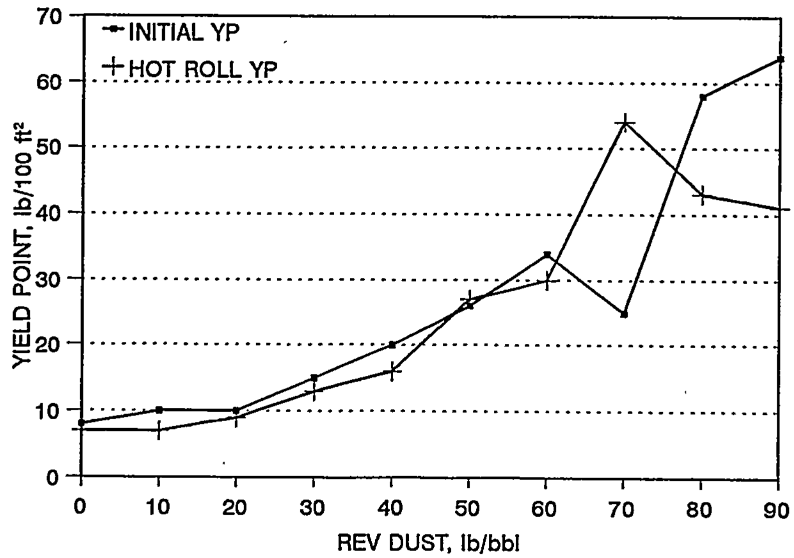

Figure 4-19. Effect of Drill Solids on PHPA HGS Mud (YP)

The slope of the curves in both the PV and YP plots changes at around 40-50 ppb of drill solids (about 5-6% drill solids by volume). This behavior suggests the need to maintain the concentration of drill solids below 5-6%. This requirement is consistent with normal practice for PHPA muds, which are usually run as low-solids drilling fluids.

Figures 4-20 and 4-21 show that gel strength increases with increasing concentrations of drill solids. Without the use of thinners, gel strength will attain values that are too high to manage in field applications when drill-solids content reaches 40 to 50 ppb (5-6% by volume). The effect is most pronounced on the plot of hot-rolled mud gel strengths. Higher temperatures than the 150°F used for hot rolling may make this effect even more dramatic or occur at a lower drill-solids content.

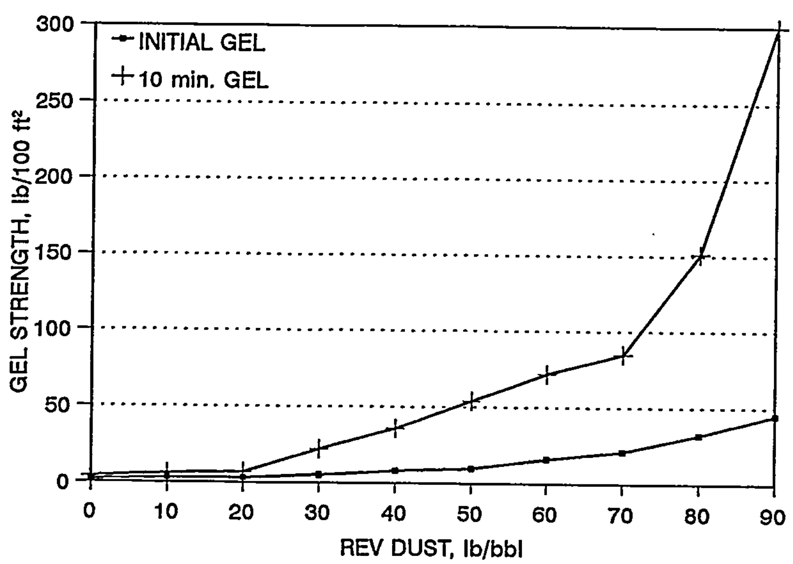

Figure 4-20. Effect of Drill Solids on PHPA HGS Mud (Gel Strength)

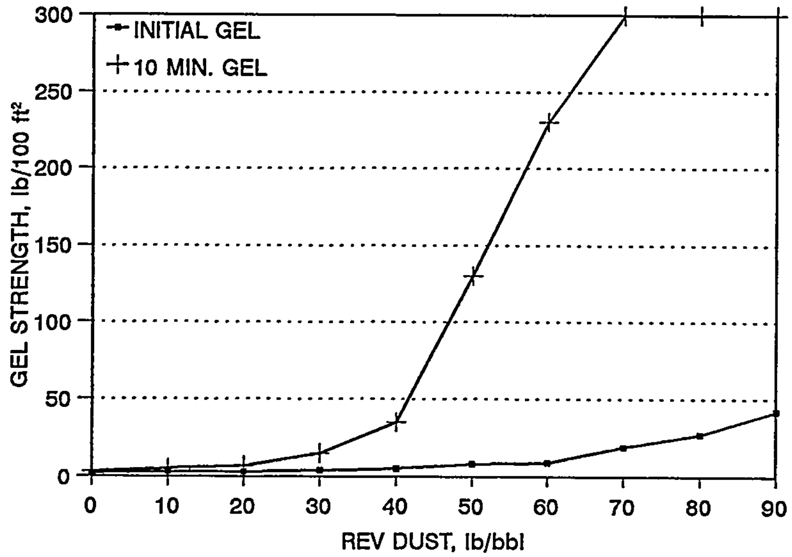

Figure 4-21. Effect of Drill Solids on Hot-Rolled PHPA HGS Mud (Gel Strength)

Fortunately, the addition of 0.25 to 1.0 ppb of common polymer thinners will lower the gel strength to acceptable limits.

A PHPA mud composed of 50 ppb (26%) HGS and 50 ppb (5.5%) drill solids was treated with several deflocculants, both before and after hot rolling. In a typical test, 1.0 ppb of a common thinner reduced the 120°F 10-min gel strength from 44 to 10 lb/100 ft^2. After hot-rolling, the thinner reduced the 10-min gel from 68 to 12 lb/100 ft^2. The same thinner reduced the hot-rolled PV from 36 to 33 cp and the YP from 20 to 15 lb/100 ft^2. These results show that thinner will be required with HGS muds containing higher concentrations of spheres and drill solids.

Typical gel strengths of PHPA HGS fluid after hot-rolling are shown in Table 4-5. Gel strengths after treatment with three anionic polymer deflocculants, one cationic polymer deflocculant, and chrome-free lignosulfonate are compared to gel strength of an untreated mud. Lignosulfonate was also used as a thinner, but its use is not recommended since it contains chrome. In all cases, gel strengths were reduced, with four of the six thinners producing significant reductions.

TABLE 4-5. Effect of Deflocculants on PHPA HGS Mud (Gel Strength)

	Gel Strength (lb/100 ft^2)	
Additive (1.0 ppb)	Initial	10 Minute
None (untreated)	6	68
Polymer A	5	12
Polymer B	5	44
Polymer C	4	15
Polymer D (Cationic)	5	28
CF-Lignosulfonate	3	9

Oil-Base Mud Contamination

Tests were performed on oil-base mud to determine the impact of contamination by drill solids, fresh water and brine water. HGS concentration was held constant at 50 ppb (about 26% by volume) while the contaminant concentration was increased. REV dust was used to simulate drill solids. Brine water contamination was simulated using saturated NaCl water.

Figure 4-22 shows that both PV and YP of the oil-base mud increased as the REV dust concentration was increased to 40 ppb (approximately 4% by volume). The impact on PV was very small, raising it from 41 to only 48 cp. YP more than doubled from 19 to 39 lb/100 ft^2.

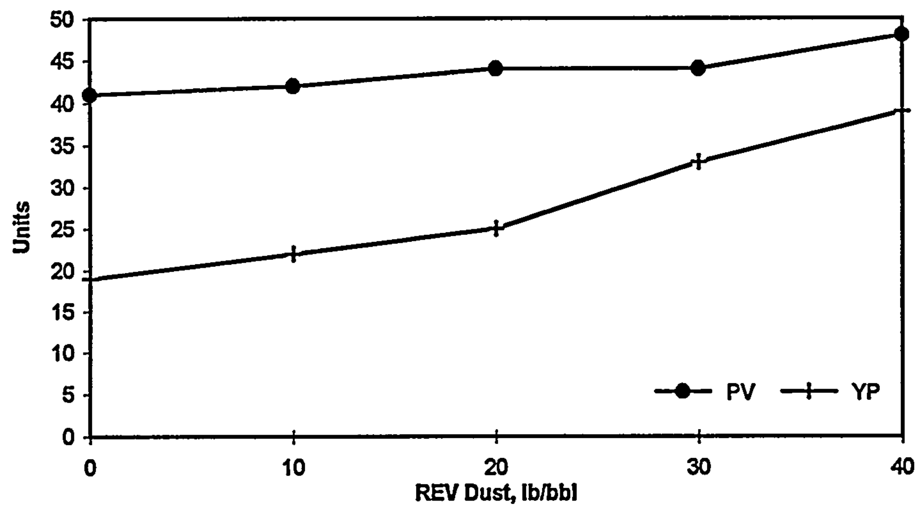

Figure 4-22. Effect of Drill Solids on Oil-Base HGS Mud (PV and YP)

The data shown are for samples before hot-rolling. After hot-rolling, there were smaller increases for both PV and YP. PV of the hot-rolled sample increased from 49 to 54 cp, while the YP increased from 19 to 36 lb/100 ft^2. These results again demonstrate that oil-base muds are less affected by temperature than water-base muds.

Increasing solids content affected the gel strengths of water-base mud more than any other property. This was not true for HGS oil-base muds. Both the initial and 10-min gel strengths increased only slightly as the simulated drill-solids content was increased (Figure 4-23).

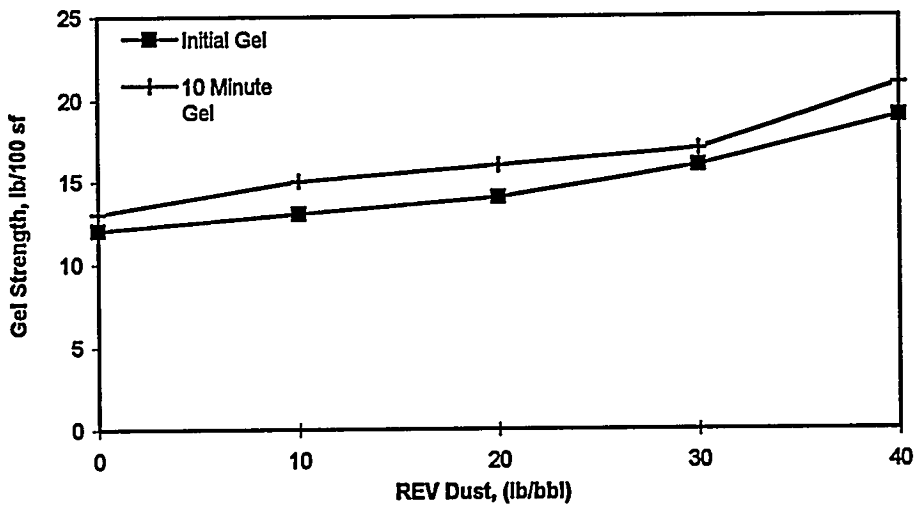

Figure 4-23. Effect of Drill Solids on Oil-Base HGS Mud (Gel Strength)

Gel strengths for the HGS oil-base mud tended to start higher than those for either conventional oil-base mud or for HGS water-base mud. However, unlike the water-base HGS mud gels, oil-base gel strength remains very flat and non-progressive. Of the thirty-four oil-base HGS mud samples tested, the 30-min gel strength never exceeded the 10-min gel strength by more than 1 lb/100 ft^2.

Contamination with both fresh and salt water was tested at water concentrations of 5, 10, 15, and 20% by volume. Water contamination had very little effect on the oil-base HGS mud at those concentrations.

Figure 4-24 shows that electrical stability (ES) decreased as the concentration of either type of water increased. This behavior is typical for oil-base muds. ES decreased from 647 volts to 376 volts and 362 volts for saltwater and fresh water, respectively, indicating that the emulsion is still relatively stable with up to 20% water contamination.

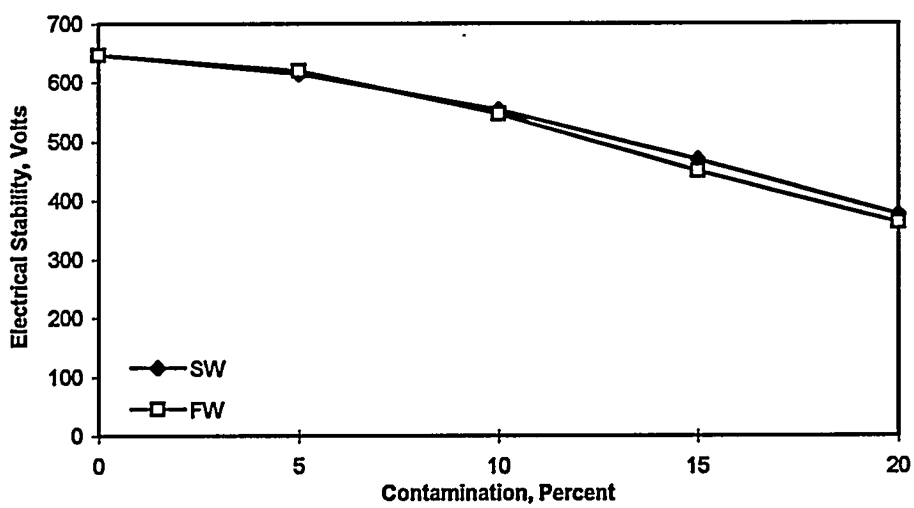

Figure 4-24. Effect of Water Influx on Oil-Base HGS Mud (ES)

These tests showed that oil-base HGS mud behaves similarly to conventional oil-base muds when contaminated with either drill solids or water. The impacts on the performance of the mud were minimal. Consequently, no attempts were made to test treatments for oil-base HGS mud to overcome the effects of contamination.

4.3.4 Sphere Recovery

Because of the high cost of hollow glass spheres, durability and recoverability of the spheres are critical to the economic use of HGS fluid. The percentage of spheres recovered at the conclusion of drilling operations for recycling will determine whether the spheres will be competitive with conventional fluids. A sphere recovery rate of 50 to 100% is expected to make HGS mud costs competitive with aerated fluids in many applications.

Conventional low-gravity drill solids (SG=2.6) and weighting materials such as barite (SG=4.3) settle in the drilling fluid, whereas HGS tend to float upward in the drilling fluid because of buoyancy. The ratio of the densities of water to HGS is 2.6, about the same as the ratio of the densities of low-gravity solids (sandstone, limestone, shale) to water. The rate of gravity segregation should therefore be similar in both cases, except that HGS tend to float and drill solids and barite sink.

Laboratory tests showed that the simplest and fastest way to recover the spheres from HGS muds is to take advantage of the natural tendency of the lightweight spheres to float to the surface of the mud, especially when HGS muds are diluted with water. Laboratory tests were performed to determine rates and percentages of recovery of spheres by flotation techniques.

In the first test, five samples of a clean HGS mud containing 10 ppb of bentonite, 35% HGS, and 2% sand were tested at water dilution levels of 0 to 80%. Fifty-percent dilution corresponds to two parts of HGS mud and one part water.

The amount of sphere separation was recorded as a function of time. Sphere recovery from the sample with no dilution reached a plateau of 84% after 30 minutes and 88% after 24 hours. All the other samples reached recoveries of about 93% after 17 minutes, and 93-95% after 30 minutes. The manufacturer's specification for the spheres is that 90% will remain buoyant in long-duration tests.

Figure 4-25 shows that higher dilution rates with water may not increase ultimate sphere recovery, but will slightly accelerate the recovery process in the early time period (i.e., the first 15 minutes). For example, after 8 minutes, only 70% of the spheres had been recovered with a dilution of 20%. With a dilution of 80%, approximately 83% had been recovered. Since ultimate recovery is the same in a relatively short time period, money and time can be saved by limiting dilution rate when the mud is relatively clean.

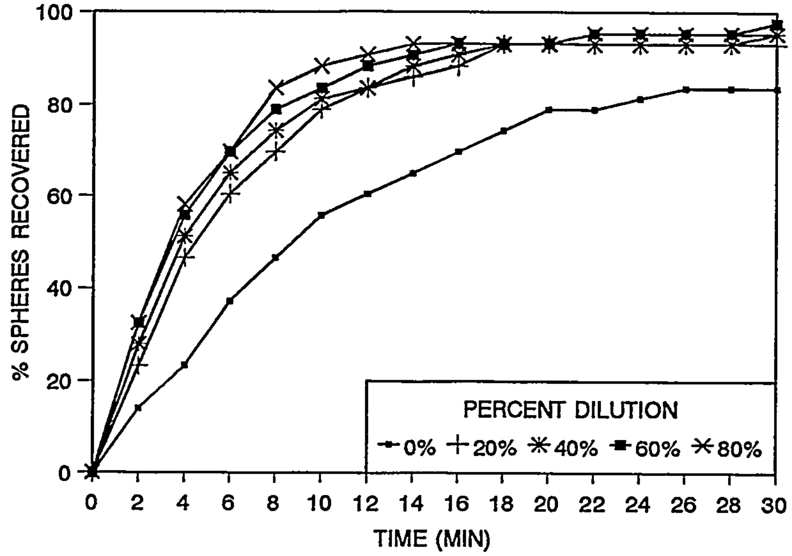

Figure 4-25. Gravity Separation of HGS in Clean Mud

The second separation test was conducted with HGS mud containing 38% spheres and 50 ppb (5.5% by volume) simulated drill solids. The simulated drill solids included both fine silica and clay. The samples were diluted with 20 to 100% fresh water. A dilution of 20% was selected as the initial test condition because a visual determination of sphere recovery with no dilution was difficult in the dirtier mud.

Both ultimate recovery and rate of sphere recovery increased with increasing dilution, as shown in Figure 4-26. Sphere recovery rate and ultimate recovery were observed to be lower when the percentage of low-gravity solids is higher. The longer lightweight HGS mud is used in a well without being recovered, the more difficult recovery will be. The ultimate recovery of spheres reached a plateau for all levels of dilution, remaining nearly constant after 30 minutes.

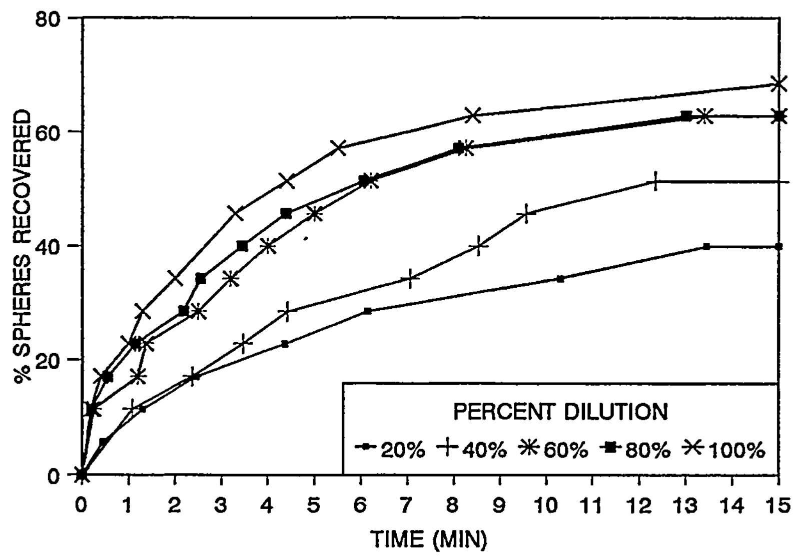

Figure 4-26. Gravity Separation of HGS in Solids-Loaded Mud

Figure 4-26 shows that with 20% water dilution, only 40% of the spheres were recovered after 15 minutes. With 100% dilution, 70% were recovered. These data and the tests in clean mud both show that rate of recovery and ultimate recovery accelerate with increasing amounts of dilution. This will impact the cost and time involved in recovering HGS in the field.

In areas where water is inexpensive, higher rates of dilution should be used to speed up the separation process. Where water is expensive, dilution pilot tests should be run to determine recovery efficiencies for the specific mud in question. The cost of dilution water can then be balanced against the cost of time required for optimum recovery.

The recovery process did no damage to the spheres. All recovered spheres should be reusable. A sphere recovery rate of 95% will allow virtually all the spheres to be reused, and sphere make-up cost will be minimized. There apparently is no limit to the number of times the spheres can be reused, although the future field testing may reveal a limit.

If the sphere recovery rate is only 70%, make-up cost, or mud building cost, for each additional well in the project will be 30% of the cost of the original well. The benefit of using the spheres will necessarily need to be approximately 30% higher than for the case mentioned above.

The field tests in Phase II of the project will be required to determine actual costs and time required for sphere recovery.

4.3.5 Other Tests

Abrasivity. A standard API abrasion test was performed on a fresh water-base mud containing 90 ppb (40% by volume) of hollow glass spheres. The test was performed by mixing the fluid with a multimixer (i.e., a blender) using a new mixing blade. The blade was weighed before and after stirring the fluid for 30 minutes, and the resulting blade loss was reported as abrasiveness in mg/min.

Three tests were conducted with the HGS fluid, with very consistent results. The abrasiveness of the HGS fluid was measured as 0.2, 0.1, and 0.15 mg/min. These data indicate that the abrasiveness of the HGS fluid is low. This level of abrasiveness is comparable to that typically measured on API grade barite.

Use of hollow glass spheres does not appear to present an abrasion problem. Although the abrasiveness measured was low, the mixing blades were polished to a high shine during the test.

Lubricity and Casing Wear. Solid plastic and glass spheres are routinely used to reduce friction in high-angle and horizontal wells. Hollow glass spheres therefore have potential for reducing friction and casing wear. To test these properties, HGS were mixed with a conventional water-based mud and tested in a casing-wear test machine.

For a typical test, 9⅝-inch, 47 lb/ft, N-80 grade casing is subjected to the grinding action of a conventional smooth steel drill-pipe tool joint that is rotated at 120 rpm under a lateral load of 3000 lb/ft, simulating the action of a drill string rotated inside casing. This test yields measurements of friction factors and casing wear with different drilling fluids.

A water-based mud containing 35% by volume HGS was used in a standard casing-wear test for 8 hours. HGS were observed to have a significant impact on casing wear. The measured friction factor, 0.18, was comparable to that of a standard fresh-water base fluid. However, casing wear was reduced by 78% (i.e., from 18% of the wall thickness with a standard mud to 4% with HGS mud). With 2% sand added, casing wear was reduced by 65% (i.e., from 20 to 7%).

Lost Circulation. A fresh water-base fluid containing 50-90 ppb (26-40% by volume) of hollow glass spheres was tested using a standard API slot testing procedure in an attempt to determine the effectiveness of the spheres in controlling lost circulation. During a slot test, the fluid is pumped under pressure through a slotted apparatus. A "successful" test for lost-circulation material occurs when the material bridges off across the slot and hold 1,000 psi for 10 minutes. Normally, slots having widths of 1 – 5 mm are tested.

The hollow glass spheres are not effective as a lost-circulation prevention material based on this test. At an HGS concentration of 50 ppb, the HGS fluid would hold only 250 psi across a 1-mm wide slot. When the sphere concentration was increased to 90 ppb, the fluid held only 700 psi across the same slot. No other slot widths were tested.

Use of an HGS mud in lost-circulation areas should normally be accompanied by use of some other lost-circulation material. In some cases, the HGS fluid may have a density low enough to prevent lost circulation on its own.

4.4 YARD TESTING

A variety of yard tests were performed with HGS muds using conventional drilling rig solids-control equipment, including centrifugal pumps, a shale shaker, hydrocyclones, and a high-speed centrifuge. The effects of conventional equipment on lightweight drilling fluids containing HGS is important with respect to two considerations.

Firstly, spheres must not be broken when subjected to the forces and pressures exerted by conventional rig pumps and solids-control equipment. At the same time, drill solids accumulating in the mud need to be removed to maintain mud properties, as described in the preceding section.

Secondly, solids-control equipment should assist in the recovery of the hollow spheres. This may mean simply keeping the mud clean enough to remove the spheres by dilution, as described earlier, or it may mean actually separating the HGS from the whole mud.

The yard tests were carried out using a PHPA fresh water-base fluids. These muds were composed of water, 5-10 ppb of bentonite, 0.25 ppb equivalent of ASP-700, and varying concentrations of HGS and simulated drill solids. ASP-700 is a long-chain, high molecular weight, partially-hydrolyzed polyacrylamide (PHPA) polymer added to fluids as a viscosifier.

4.4.1 Solids Control

All solids-control tests were carried out using a flow loop consisting of a mix tank, centrifugal pump, and the individual solids-control equipment. The drilling fluid was circulated through the pump, through the solids-control equipment, and back into the original mixing tank. All solids-control underflow and overflow components were put back into the original tank. Damage assessment was made by monitoring changes in total fluid density.

Samples were taken from the mix tank, the overflow and the underflow of each piece of solids-control equipment for each test, where applicable.

The *underflow* of the hydrocyclones and the centrifuge is that part of the exit stream designed to carry the larger and heavier components of the drilling fluid. Normally these are composed of drill solids. The *overflow* is designed to carry the lighter components, normally the liquid phase and the more highly dispersed, smaller solid particles.

The opposite nomenclature is used in reference to the shale shaker. A shaker screen overflow will divert the larger and heavier solid particles out of the main flow. The underflow will contain the lighter, smaller fractions of the flow stream when used with conventional muds.

Throughout the yard tests, the HGS fluids were observed to behave similarly to conventional fluids. Lighter, smaller particles were directed in line with equipment design. However, in the case of an HGS mud, the lighter smaller particles tended to be the hollow sphere solids.

Mud Mixing. Two mix tanks were used for the yard tests. A 100-gallon tank was used for initial hydrocyclone testing. Later, all mud was mixed in a small drilling-rig compatible steel tank. The total capacity of the tank was approximately 35 bbl. The maximum volume of mud mixed at any one time was 15 bbl.

The tank set-up included a conventional paddle mixer capable of mixing a 250-bbl tank. Two mud jet guns were installed in corners of the tank. All or part of the centrifugal pump output could be diverted to operate these guns for additional mixing.

Mud products were introduced into the tank primarily by cutting product bags and slowly pouring additives into the mixer stream. Proper dust masks, gloves, and eye protection were in use at all times during mixing operations. The HGS in particular can present a dust hazard in their dry state. The smaller the particles, the worse this hazard may be.

A pneumatic jet gun was used to reduce dusting potential during mixing operations. The jet gun consisted of a pressurized air supply, an inlet hose and an outlet nozzle. The outlet was extended into the mix tank using a hose extension to a point just above the surface of the fluid being mixed. The inlet hose was introduced into the bag containing the spheres, and the vacuum created by the air jet drew the product through the gun and ejected it into the tank. This procedure worked well and helped mitigate dust problems. **This method did not damage the spheres, as determined by mud density checks.**

The jet gun has good potential as a method of introducing lightweight solid additives into drilling fluids. Any such gun needs to be optimized with respect to size. An additional air jet needs to be included near the suction line of the apparatus. This additional air supply would keep the product from compacting in the bag around the suction line, and would speed up the mixing process.

Centrifugal Pumps. Centrifugal pumps, which are used to transfer drilling fluids between tanks and solids-control equipment, impart some of the highest shear stresses to which the mud is subjected. Tests were conducted to determine if the high-speed impeller blades in these pumps would break the spheres.

A 40-HP transfer pump (5 x 6 centrifugal pump, 9.5-in. impeller, 1765 rpm) was used to move the HGS muds during yard testing. During the first series of tests, a mud containing 37% HGS was circulated through the centrifugal pump for a total of 4 hours. During a second test series, an HGS mud with 45% spheres was circulated for a total of 12 hours.

Density of the drilling fluids was measured periodically to determine if hollow sphere breakage was occurring. An increase in mud weight (fluid density) would indicate that spheres were being damaged to the point of failure, causing them to sink and allowing the entrained air to escape. There was no measurable increase in fluid density during any test, indicating that the spheres were not damaged by the centrifugal pump.

Triplex Pump and Nozzles. A conventional rig-compatible triplex pump was used to determine the effect on the spheres. A 0.35-inch diameter jet nozzle was installed on the end of a discharge line to generate backpressure at the pump outlet.

A mud containing 28% HGS by volume was circulated through the triplex pump for 5 hours. The pump rate was 60 GPM and pressure was maintained at 420 psi through the nozzle. The nozzle discharge was circulated back into a mud tank containing the original mud.

Density of the fluid was measured at the end of each hour, and remained constant at 7.0 ppg. After 5 hours, the mud was diluted with water. Sphere recovery showed no damage to the spheres. The constant fluid density also confirmed that no spheres were damaged by the pump.

Shale Shakers. The primary piece of solids-control equipment on a rig is a shale shaker, so the effectiveness of shaker screens when using HGS is of primary importance. Mud containing spheres must be able to pass through the shaker, with larger drill cuttings retained on the screen and without damaging or removing significant portions of HGS.

Standard laboratory sieve tests were used to determine which mesh shaker screens to use in yard tests with conventional rig shakers. Samples of PHPA HGS mud containing 45% spheres and 2-4% sand were tested with 325-, 200-, 100-, and 50-mesh screens, which correspond to screen opening sizes of 44 to 279 microns (0.0017 to 0.0110 inches). Considering the sphere particle-size distribution, 44% of the HGS should have passed through the 325-mesh screen, and 100% through the 100- and 50-mesh screens.

In the initial test of 10 minutes, the sieves were "blinded" (heavily loaded with mud). One-hundred percent of the mud passed through the 50-mesh sieve, 17% through the 100-mesh sieve, and none passed through the 325-mesh screen (Figure 4-27).

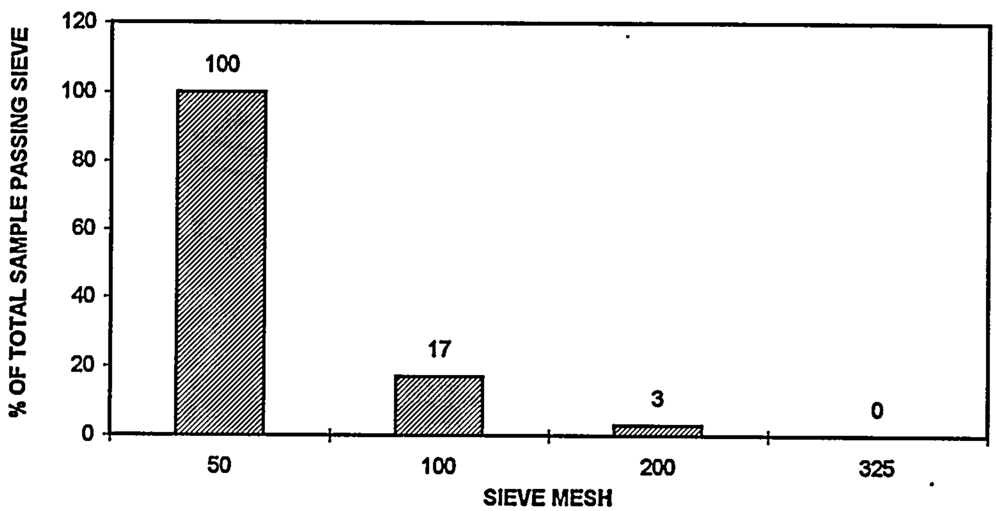

Figure 4-27. Blinded Shaker Screen Tests

In the second test, a smaller volume of HGS mud was poured onto a clean 200-mesh sieve (74 micron opening) to simulate an "unblinded" screen. Based on the particle-size distribution, 80 to 85% of the spheres should have passed the 200-mesh sieve (i.e., 15 to 20% should be retained). In laboratory tests, the 200-mesh sieve retained 45% of the mud volume, including 20% of the original HGS in the mud sample, indicating that typical shale shaker screens should be capable of passing or retaining the expected particle sizes as long as the screens do not become blinded.

Based on these preliminary laboratory tests, 100-mesh and 200-mesh shaker screens were selected for yard testing. A 100-mesh screen theoretically should pass 100% of the HGS, while retaining drill cuttings larger than 140 microns. A 200-mesh screen should pass 80 to 85% of the spheres, while retaining drill cuttings larger than 74 microns.

The base drilling mud for the yard tests contained 40% by volume K-37 HGS (86 ppb), 7 ppb bentonite, and 0.33 ppb ASP-700 viscosifier. A series of tests was run as the concentration of simulated drill solids was increased. Drill solids were simulated by the addition of foundry clay, similar to REV dust and commonly used for this purpose, and fine silica flour.

The shale shaker used was a small rig-compatible conventional single screen shaker. The capacity of the shaker is 150-200 gpm, according to the manufacturer. A 100-mesh screen was selected for the initial test.

During the initial shale shaker test, no simulated drill solids were added to the fluid. The only solids in the mud were the HGS, bentonite added for viscosity, and any residual solids that may have been present in the tank, flowlines, or pump. Figure 4-28 shows the shaker performed as expected in the initial test. Heavier components of the flow stream were discarded by the shaker screen and the lighter components passed through the screen.

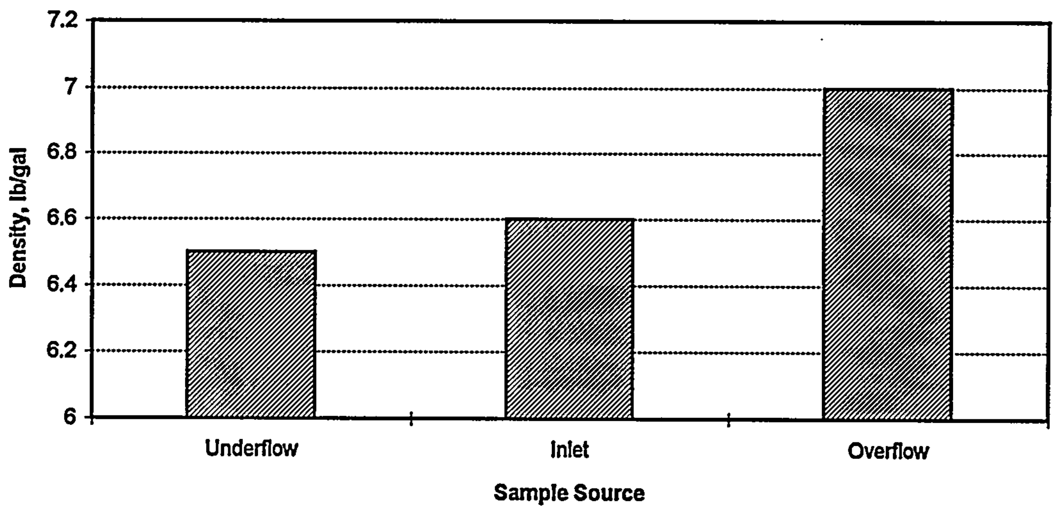

Figure 4-28. Effectiveness of Shale Shaker with 100-Mesh Screen (No Drill Solids)

Figure 4-29 shows that, after 9 ppb of foundry clay was added to simulate drill solids, the shaker did not function as expected. Instead, the heavier flow stream passed through the shaker and the lighter portion, probably containing a higher concentration of HGS, was discarded. The HGS concentration in the underflow was the same as that in the tank originally, indicating that very little HGS separation was taking place.

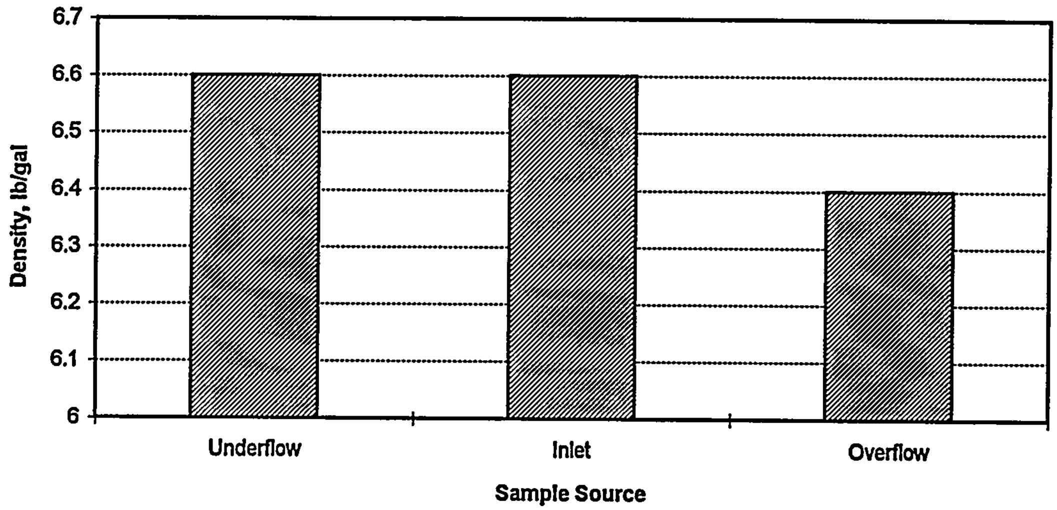

Figure 4-29. Effectiveness of Shale Shaker with 100-Mesh Screen (9 ppb Drill Solids)

In both 100-mesh screen tests, the overflow (conventional discards) represented about 40% of the total flow. This was deemed an unacceptable discard rate. With a 50-mesh screen installed on the shale shaker, 100% of the flow of clean fluid (i.e., no drill solids) passed through the shaker. No hollow glass spheres were discarded at lower flow rates. **A larger mesh shaker screen will be required to handle HGS fluids.**

The observed phenomenon of large percentages of flow failing to pass shaker screens is not uncommon, especially for lightweight fluids. Very low density oil-base muds (e.g., 7.0 ppg) often will not pass through a screen mesh that easily passes a heavier mud. When this happens, the only recourse may be to use a coarser mesh screen.

The original testing plan called for using screens on the shale shaker for the second series of tests. Since nearly half of the lightweight fluid would not pass the 100-mesh screen, a 20-mesh screen was selected for additional shaker testing. This allowed the maximum screen size to be determined.

The second test series was run using a lightweight mud containing approximately 50 ppb simulated drill solids (5% by volume), including clay and silica. The mud also contained 33% HGS by volume (70 ppb).

At all flow rates, 100% of the flow passed through the 20-mesh screen. The mud density of both underflow and tank samples remained constant at 7.4 ppg. No spheres were damaged by the action of the shaker.

Lightweight HGS muds will require coarser screens than are conventionally used on a drilling rig. This is necessary to prevent an unacceptable sphere discard rate. A surfactant may be found during Phase II testing that will help the fluid pass through finer mesh screens.

Coarser screens have been used successfully in other lightweight fluid applications (e.g., oil-base muds). For operations with HGS muds, the hydrocyclones will become more important for keeping the mud clean than in a conventional drilling-fluid application.

Conventional Hydrocyclones. Hydrocyclones, or cones, when operated properly, can remove smaller particles than shale shakers. Cones separate particles from mud using centrifugal force to accelerate the natural process of gravity separation. Separation rate is dependent on solid particle density and size, as well as the size of the hydrocyclone.

In normal operation, sand or other drill solids, due to their higher density, move toward the outside of the cone and flow out the bottom of the cone. Liquid flows to the center and then upward out of the top of the cone. HGS (low density) move to the center of the cone and flow out the top of the cone with the fluid. Normally, the larger the cone diameter, the higher the volume it can handle and the larger the particle size that will be separated.

Optimum loading conditions for hydrocyclones depend on inlet pressure, which increases with increased fluid density. For optimum operation, most cones require 70 to 80 ft of hydraulic head at the inlet. Because the density of HGS muds is much lower than conventional muds, the cones will operate at lower inlet pressures.

The mud used for initial testing contained 45% by volume K-37 HGS. Mud weight measurements before and after passing the mud through a 5-in. diameter hydrocyclone show that the spheres were not damaged. The mud weight was the same at the inlet and the overflow. The underflow was slightly heavier, indicating that some separation was occurring in the cone and the spheres were being concentrated in the overflow. However, the pressure head during these tests was only 40-45 ft, well below the recommended head.

The hydraulic head problem was solved by first increasing the centrifugal pump size from a 4 HP to a 40 HP unit. The suction-line diameter was increased from 2 to 4 inches. Before the line was changed, inlet flow to the pump was restricted, causing the centrifugal pump to cavitate. This prevented the flow rate from increasing, thereby limiting the inlet head. After the modifications were implemented, no further problems were experienced with regulating flow rate or pressure.

Solids contamination of the mud was simulated with the addition of 4% by volume 20/40-mesh sand for the initial testing of the hydrocyclones. The mud weight with this mixture was 6.7 ppg. Four-inch and 5-in. diameter hydrocyclones were selected for initial testing since these are common oil-field sizes.

An HGS mud composed of 5 ppb bentonite, 0.25 ppb high molecular weight PHPA, 45% HGS, and 4% sand was circulated through the cones at three different flow rates, corresponding to pressure heads overlapping the manufacturer's recommended head. Table 4-6 shows properties of the fluid at the inlet, overflow, and underflow of the 5-in. hydrocyclone during the initial test, which was made with 75 ft of pressure head. Additional tests were run with the 5-in. cone at 90 and 105 ft of head.

TABLE 4-6. Hydrocyclone Fluid Sample Properties

Sample Source	Inlet	Overflow	Underflow
Average Density (ppg)	6.82	6.76	11.1
Retort Solids (%)	38	29	37
Flow Rate (gpm)	73	72	1

The density of the underflow indicates that sphere separation is occurring in the 5-in. hydrocyclone at all inlet pressures (Figure 4-30).

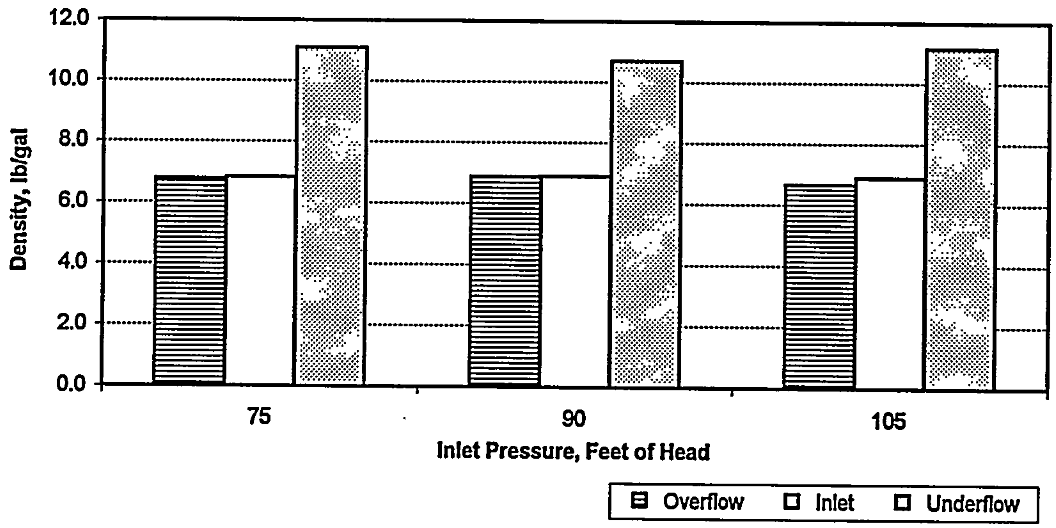

Figure 4-30. Effect of Inlet Pressure in 5-Inch Hydrocyclone

Figure 4-31 shows solids removal rates for the 5-in. cone operating at pressure heads of 75, 90, and 105 ft. At 105 ft of head, the hydrocyclone was most efficient. This level of inlet head is preferred by some operators over that recommended by most manufacturers.

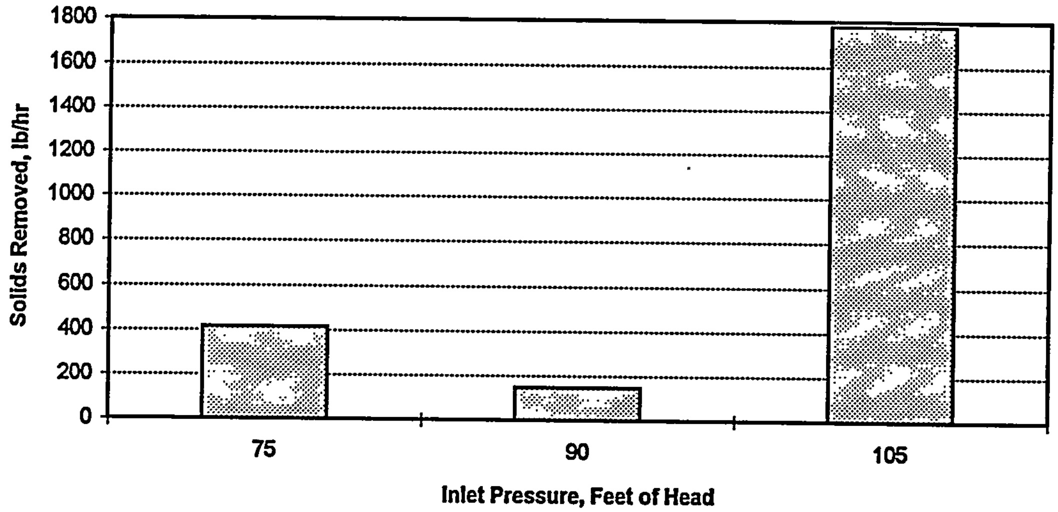

Figure 4-31. Solids Removal in 5-Inch Hydrocyclone

The 4-in. hydrocyclone was tested at inlet pressure heads of 65, 80, and 100 ft. Figure 4-32 shows that the 4-inch cone performed well at all three inlet heads. The sand concentrated at the underflow and the lighter spheres at the overflow.

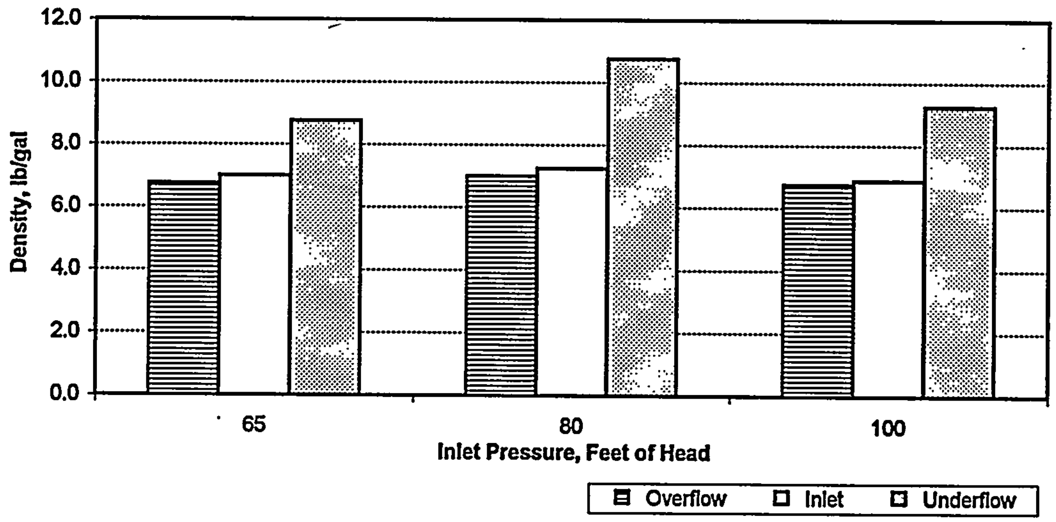

Figure 4-32. Effect of Inlet Pressure in 4-Inch Hydrocyclone

Calculated solids removal rates for the 4-in. cone operating at all three pressure heads is shown in Figure 4-33. This cone was most efficient at 80 ft of inlet head, which corresponds to the manufacturer's recommendation. Inlet pressures higher than recommended were also tested. Although these levels are preferred by some operators, these pressures proved to be the least efficient in this case, demonstrating that each situation requires individual evaluation. For initial operation, the manufacturer's recommendation should be followed.

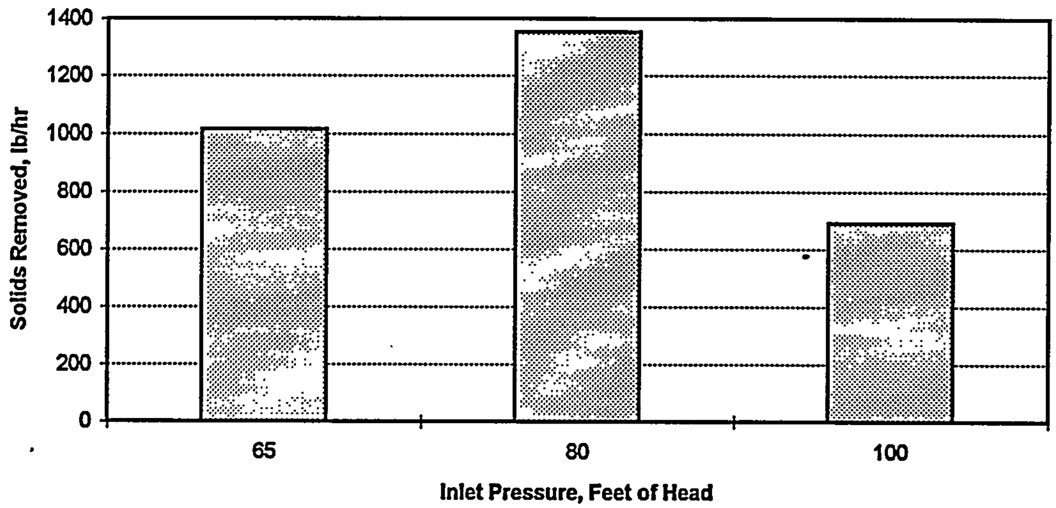

Figure 4-33. Solids Removal in 4-Inch Hydrocyclone

The 4-in. hydrocyclone was able to make distinguishable cuts in these tests also. Even with low amounts of simulated very-fine drill solids in the mud, the cone separated heavier particles to the underflow and the lightweight additives to the overflow with the bulk of the flow stream.

Conventional Centrifuge. The same HGS mud tested in the shaker and hydrocyclone was tested using a drill-rig-compatible, high-speed decanting centrifuge. Multiple tests were conducted for which simulated drill-solids loading, speed of the centrifuge, feed rate to the centrifuge, and weir height inside the centrifuge were varied. Varying the weir height has the effect of creating either dry or wet underflow with high or low height settings, respectively.

In all of the tests, a majority of fluid exited the centrifuge through the underflow ports where solids normally exit. The maximum flow measured in the overflow was 15% of total flow, which occurred at the lowest feed rate tested.

Figure 4-34 shows that, with the weir set at the highest setting, the centrifuge was able to make a separation on the basis of density. The overflow, normally the lighter portion of the flow stream, was 9% higher than the inlet density. The underflow was 4.5% lighter than the inlet density. With conventional drilling fluids, the opposite typically occurs.

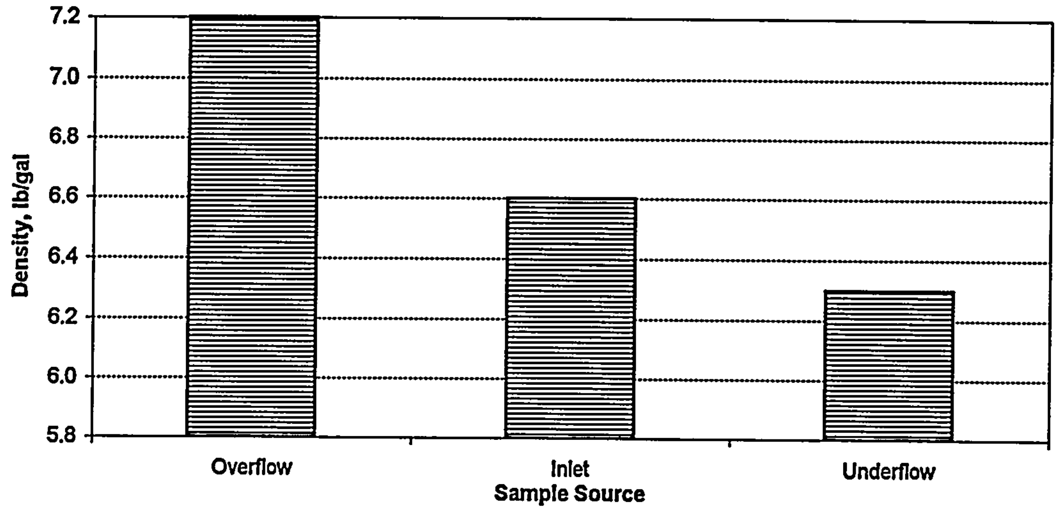

Figure 4-34. Centrifuge Flow Separation by Density

As solids content increased, percentage overflow decreased. With lower drill-solids content, feed rate did not affect percentage overflow, whereas with higher solids content, increasing feed rate decreased the percentage overflow.

As the rate of drill solids increased (i.e., with higher solids concentration in the fluid or at higher feed rates), the auger of the centrifuge began to plug since the machine was designed to handle wet overflows and dryer underflows. With drill-solids concentrations of 50 to 55 ppb (5.75% by volume), the auger became plugged, rendering the centrifuge unusable.

HGS mud was apparently being dewatered at high centrifugal forces, causing the hollow spheres to clump or cake together and plug the centrifuge. Future laboratory testing should be performed to determine appropriate fluid-loss additives to prevent this dewatering effect, or to identify surfactants that will prevent the spheres from clumping together under these conditions.

The auger plugging and the extremely wet flow from both underflow and overflow outlets will probably prevent the centrifuge from contributing to either effective solids control or HGS recovery in the field.

4.4.2 Mud Motor Tests

Many of the wells currently being drilled underbalanced are horizontal wells. One of the largest markets for potential growth of underbalanced drilling is in the horizontal drilling market. The ability to use lightweight solid additive (LWSA) drilling fluids in this application would greatly expand the potential market for this type of fluid. Consequently, tests were run using an HGS fluid with a slim-hole high-power mud motor developed for the Department of Energy.

The PHPA mud used in the initial tests contained approximately 33% HGS and had an original density of 7.4 ppg. Tests were run with the motor using the HGS mud pumped at 30, 70 and 110 gpm. These tests were compared to motor runs made earlier with fresh water. The HGS mud had very little effect on the performance of the mud motor.

Figure 4-35 shows that the mud-motor torque increases as differential pressure across the motor increases when fresh water is pumped through the motor. As the differential pressure increases from 200 psi to 600 psi, the motor speed remains relatively constant. Any further increase in differential pressure causes a continued increase in torque, and a corresponding decrease in motor speed. The pump rate through the motor was 30 gpm.

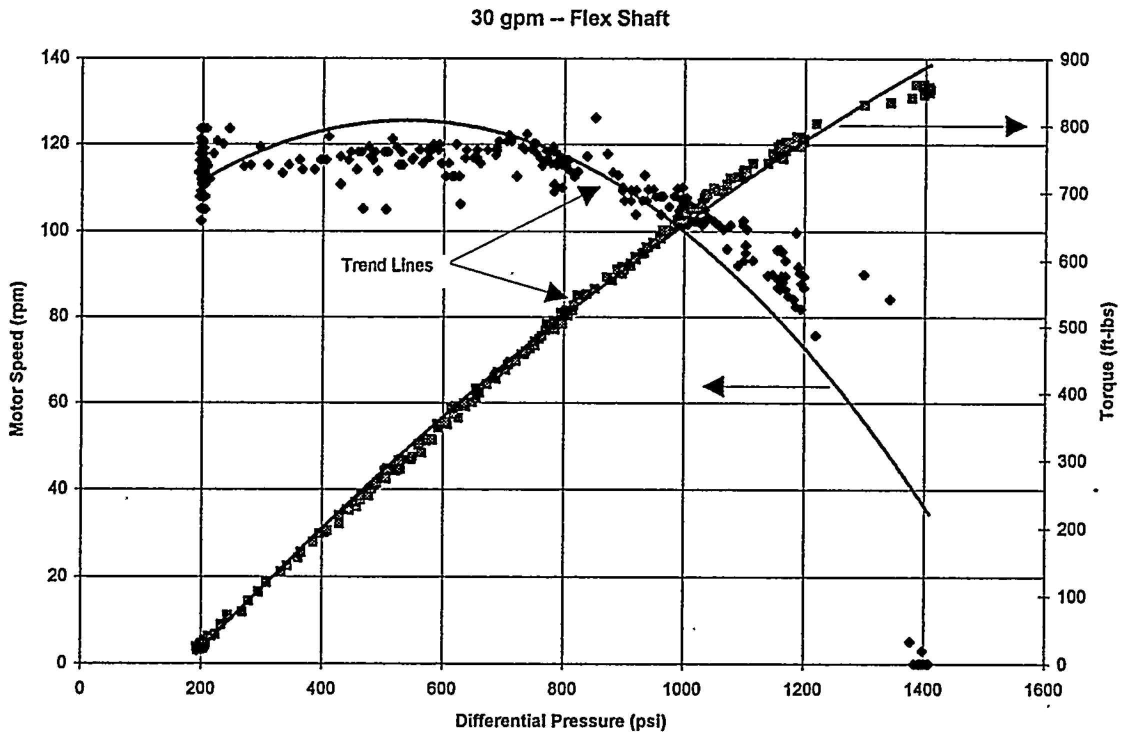

Figure 4-35. Mud Motor Performance with Water

No efficiency was lost using the HGS mud (Figure 4-36). Torque increased at a slightly lower rate than with water as the differential pressure increased. A small reduction in motor speed, compared to that achieved using water, was observed at all differential pressures. This indicates that slightly increased torque is required to turn the motor when using an HGS mud.

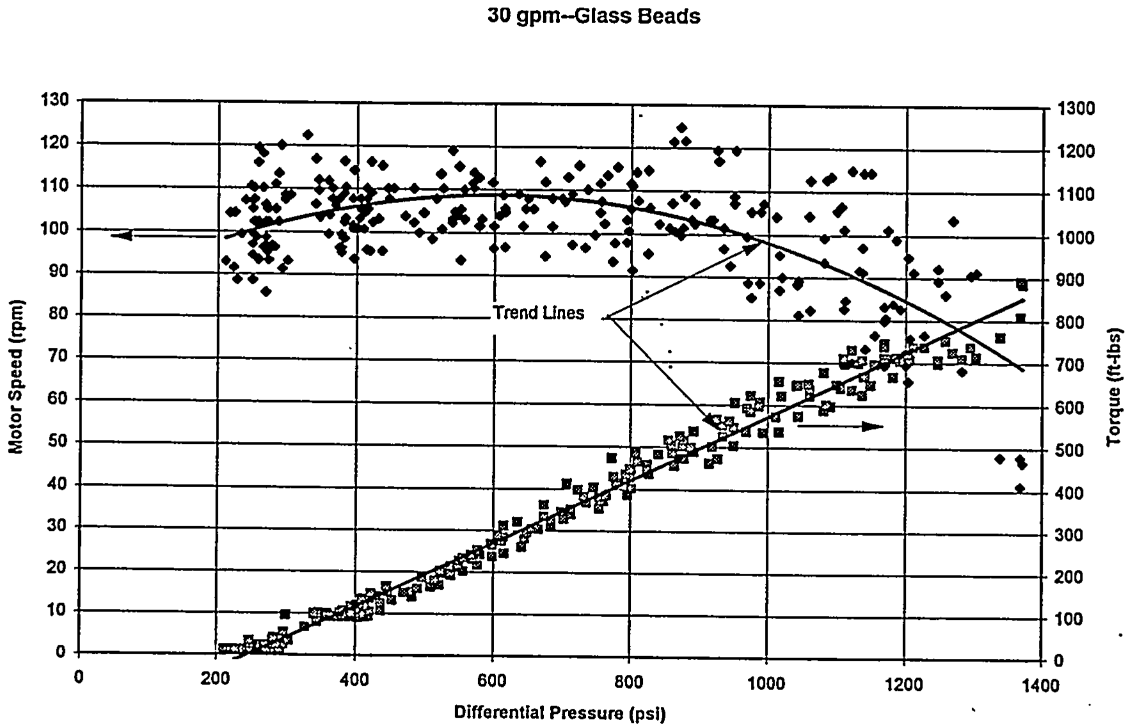

Figure 4-36. Mud Motor Performance with HGS Mud

4.4.3 MWD Tests

MWD tests were not included in the original proposal or contract, but attempts are underway by the project team to secure an MWD assembly for testing. The speed of sound through a medium is directly proportional to the Bulk Modulus, B, of the medium and is inversely proportional to its density, ρ. Sound waves should travel through liquids having comparable bulk moduli with comparable case.

The bulk modulus (compressibility factor) of HGS fluids is essentially the same as that of water (see Figure 4-8). Consequently, MWD signals should travel through HGS fluids in a manner similar to that through water.

During Phase II, at least two field tests will be conducted using HGS drilling fluids. Chevron and other operators have expressed high interest in field testing these fluids in their wells, because they see a major payout in their field operations if these fluids can be implemented. If possible, testing of an MWD system will be incorporated into one of the field trials.

5. Market Potential

5.1 INTRODUCTION

The use of lightweight fluids (fluids with a density less than water) for drilling oil and gas wells has historically been confined to the particular regions within the U.S.A. where it was first introduced 40 years ago. These regions include portions of the Permian Basin in West Texas and eastern New Mexico, the San Juan Basin of northwestern New Mexico, the Rocky Mountains, and the Appalachian Basin.

The use of lightweight fluids first found success in these regions because of the hard rock formations encountered. Drilling underbalanced with lightweight fluids (air, mist, and foam) resulted in large increases in penetration rate of from 4 to more than 10 times conventional drilling rates. Underbalanced drilling was found to be very beneficial because it greatly reduced drilling costs. Unfortunately, because the primary reason for using lightweight fluids in the early efforts was rate of penetration, these techniques tended to become associated with those particular regions to the exclusion of most other areas of the U.S.A.

In the last few years, the driving force for drilling has slowly shifted from an emphasis purely on cost reduction to the need to reduce formation damage as well. This shift is driven in large part by the tremendous increase in the number of horizontal wells being drilled.

In horizontal wells, drilling and completion fluids are in contact with the producing formation for much longer periods and a much larger formation area is exposed than in conventional vertical wells. Consequently, the potential for drilling fluids to damage the formation is magnified many times over.

Operators in Canada, for example, have reported productivity increases of up to 10-fold in horizontal wells drilled using underbalanced techniques as compared to horizontal wells drilled conventionally. The result is an increase in underbalanced drilling in Canada to a level ten times higher than that of only three years ago (Figure 5-1). This benefit highlights perhaps the largest potential market for lightweight drilling fluids in general.

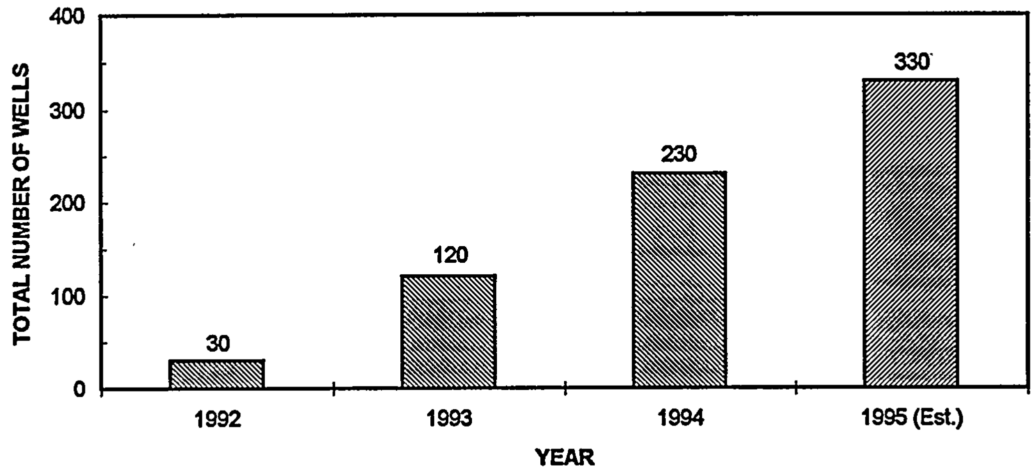

Figure 5-1. Growth of Underbalanced Drilling in Canada (Knoll 1995)

The other obvious potential market for lightweight fluids is in areas where the formations are pressure depleted. Depletion not only leads to increased formation damage, but may completely halt drilling if circulation is lost. Depletion will increase costs and risks as the potential for differential sticking in these reservoirs increases.

The increased use of underbalanced drilling resulting from concern about pressure depletion is best illustrated by the experience of one foam drilling contractor in the Hugoton field of western Kansas (Figure 5-2).

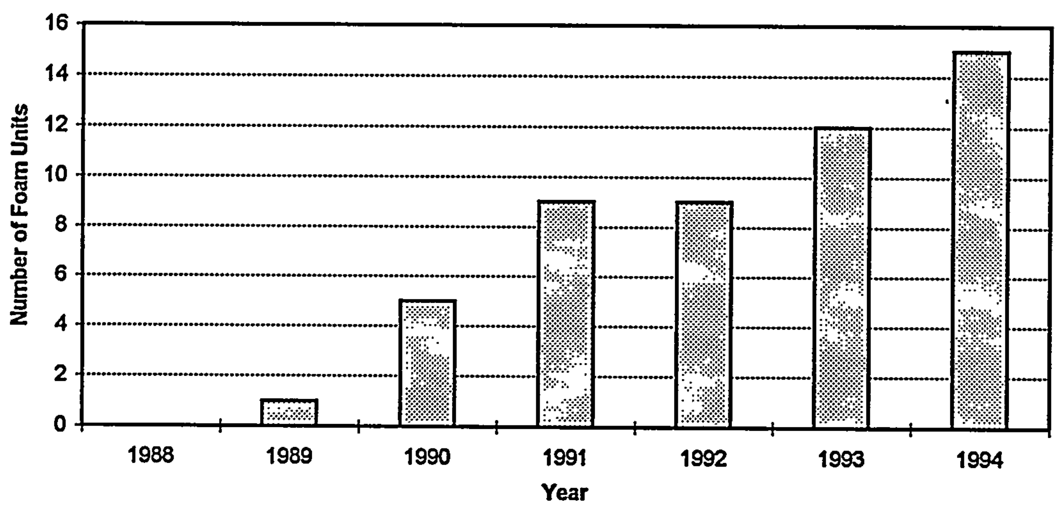

Figure 5-2. Foam Demand in West Kansas

In this area, the reservoir pressure has declined to the point that lightweight fluids are desired to prevent formation damage during re-entry horizontal work. The number of foam units in use by the contractor grew from none in 1988 to 15 in late 1994. This increased demand led a major service company to enter the market in early 1995 in this same region.

The potential market for an incompressible fluid (made up with lightweight solid additives) would include not only horizontal wells, but also many of the wells currently being drilling with air, mist, or foam. This type of incompressible fluid would overcome many of the problems associated with drilling fluids containing a gaseous phase, as described in Chapter 4.

A determination of the potential market for lightweight fluids depends on understanding the current market with regard to historical and potential growth, identifying additional areas of application, and determining the acceptability of lightweight fluids in the proposed areas of expansion. The process followed for investigating these market issues primarily depended on finding answers to several specific questions. The sources for these answers are described below.

The major questions concerning market potential for underbalanced drilling in general and lightweight fluids in particular are:

1. Is the use of lightweight fluids increasing?
2. If so, where is the increase? and
3. Are there markets where lightweight fluids are applicable that are not being exploited?

5.2 INDUSTRY SURVEY

A market study was performed to obtain answers to these questions and gauge the potential for lightweight drilling fluids. The study was designed to address the following specific issues for underbalanced drilling fluids within the U.S.A.

1. Number of U.S.A. wells currently being drilled underbalanced
2. Percentage of total wells drilled underbalanced
3. Forecasts of future drilling counts
4. Forecasts of percentage of future wells that will be drilled underbalanced
5. Locations of underbalanced drilling activity
6. Target formations for underbalanced drilling
7. Depth ranges for underbalanced drilling
8. Reasons for drilling underbalanced
9. Reasons for not drilling underbalanced
10. Reservoir types being drilled underbalanced
11. Reservoir types not being drilled underbalanced for which the technology shows promise
12. Number of wells being drilled underbalanced in nontraditional regions
13. Requirements for expansion of underbalanced drilling to new areas

14. Major players in the underbalanced drilling market, including operators, drilling contractors, air-package suppliers/vendors, drilling fluid service companies, and other related service companies
15. Current costs for underbalanced drilling, compared to costs for typical mud systems
16. Required developments to decrease underbalanced drilling costs
17. Magnitude of cost reductions required to increase underbalanced drilling utilization

Data from a broad spectrum of industry sources, including recent publications on the potential for air drilling, were evaluated and incorporated into this study. Among the most significant are "Drilling Technology Needs Assessment" by Reuben L. Graham, Inc. (October 1994) and "Technology Assessment of Vertical and Horizontal Air Drilling Potential in The United States" by Grace, Shursen, Moore and Associates for DOE-METC (August 1993).

Recent output from the DOE Energy Information Administration "Rig Model" computer forecaster was also included, as was data presented in widely available industry publications (i.e., *Oil & Gas Journal, Petroleum Engineer International,* and *American Oil and Gas Reporter*).

Maurer Engineering also contacted Petroleum Information and Spears and Associates, Inc., two private data base companies. Neither of these companies has collected well data specific to underbalanced drilling or the use of lightweight fluids in underbalanced drilling. In fact, no hard data specific to these subjects are available in any source researched (i.e., no one currently is specifically counting wells drilled underbalanced or with lightweight fluids).

All these sources were investigated to determine what percentage of current wells is being drilled underbalanced (i.e., with mud weight < 8.6 ppg). These data included a contact with Smith International to research bit records, as available. Data were also gathered from operators and service companies through ongoing informal discussions, forums such as the MEI/Drilling Engineering Association project update at the 1995 Offshore Technology Conference, and workshops. Data were obtained from service companies listing major players in the underbalanced market, cost of underbalanced services, and projections of market increases.

Discussions were held with five of the largest air drilling services contractors in the United States. The wells drilled by these contractors represent an estimated 80–90% of the wells drilled with air in the U.S. This is based on the number of wells they reported drilling compared to the total number of air drilled wells reported through the project survey.

The final source of information for evaluating the lightweight fluid market was an industry-wide survey undertaken by Maurer Engineering of companies throughout the United States that are concerned with advanced drilling technologies. These companies for the most part are current and past participants in projects carried out for the Drilling Engineering Association (DEA) and included operators as well as service companies and air-drilling contractors.

All domestic operators, service companies and equipment manufacturers who have participated in MEI/Drilling Engineering Association (DEA) projects were contacted regarding their future use of underbalanced drilling and their estimate of the market for underbalanced drilling. Participation in the survey was solicited from 63 companies.

Major players in underbalanced drilling, including operators, drilling contractors, air-package suppliers/vendors, drilling fluid service companies, and other related oil-field service companies, were contacted as they became known to the project. These were asked to supply any available pertinent data, in addition to that included in the survey, such as how they see underbalanced activity impacting their current product line, what they see as the current market, and their interest in offering underbalanced products to operators. Companies that were surveyed included several service companies that specialize in underbalanced drilling.

Survey Content

The survey instrument was designed as a two-page questionnaire (Figure 5-3) with a total of six questions covering respondents' experiences with air drilling and lightweight fluids. Questions were designed in an easy fill-in-the-blank format to minimize the respondent's time investment. Estimations were encouraged where the data might not be readily available or firmly established.

The survey requested information describing reservoir types and drilling conditions that currently exist in each area of operation. The intent was to determine not only where underbalanced drilling is currently being planned or carried out, but to identify areas where conditions may be favorable for underbalanced drilling, e.g., depleted reservoirs, horizontal wells, lost-circulation zones, hard rock, etc.

The survey was also designed to gather information about why underbalanced drilling is not being used and about what will be required to increase the level of utilization.

Prior surveys of the underbalanced drilling market have generally concentrated on air, foam, and mist drilling in geographic areas where these techniques are already common. This survey sought to identify new areas of application and include the prospective use of incompressible fluids containing lightweight solid additives.

Lightweight Drilling Fluids Survey

All respondees will be given a compilation of the survey results. Please show the address where the results should be sent:

Name: ______________________ Company: ______________________

Address: ____

City: ________________ State: ________________ Zip Code: ____________

Phone: ______________________ Fax: ______________________

Definition:

This survey pertains to the use of lightweight fluids (LWFs) with densities less than water (e.g. air/mist/foam and aerated muds).

Objective:

The survey objective is to determine the potential use of LWFs in the U.S.A.

1. a. What was your use of LWFs in 1994 and what is your projected use in 1995?

	Oil		Gas	
Year	LWF Wells	Total Wells	LWF Wells	Total Wells
1994				
1995 (est.)				

b. What percent of all wells would you guess will be drilled underbalanced within:

2 years _____ 5 years _____ 10 years _____

2. The following are reservoir types where LWFs are often used. Please indicate the percent of your reservoirs in each category:

____ Depleted Reservoirs
____ Differential Sticking
____ Fluid Disposal Problems
____ Hard Rock
____ Lost Circulation
____ Low Permeability Gas Wells
____ Slim Hole (4¾ Inch)
____ Sloughing Shale
____ Underbalanced Horizontal

3. Rank the primary *advantages* of LWFs in your area (1 =highest):

____ Environmental Benefits
____ Increased ROP
____ Increased Bit Life
____ Reduced Differential Sticking
____ Reduced Formation Damage
____ Reduced Lost Circulation
____ Other ______________

Figure 5-3. Project Questionnaire (Page 1)

4. Rank the following major *disadvantages* of LWFs in order of greatest concern (1 = worst problem).

___ Corrosion	___ High N_2 Cost
___ Difficult Hydraulics Calculations	___ Hole Erosion (Air)
___ Downhole Fires	___ Inability to Recirculate Foam
___ Fluid Influxes	___ Inability to Use MWD
___ High Chemical Cost (Foam)	___ Other ___

5. Why are LWFs not used more in your area? (Rank all that apply, 1 = most important.)

___ Economics (High Cost)	___ No Planning Tools
___ Hole Instability	___ Unfamiliarity with LWFs
___ Inexperienced Personnel	___ Well Control Concerns
___ Limited Equipment Availability	___ Other ___
___ Air Drilling Packages	
___ Fluid Handling Equipment	
___ Rotating Heads or BOPs	

6. We are developing an incompressible LWF that would overcome the problems listed in Question 4.

Would you use such a fluid? ___

How many of your wells per year would be candidates for the fluid? ___

Region(s) ___

Target Formation(s) ___ Depth Range(s) ___

Would you be interested in providing candidate wells to test such a fluid? ___

7. Comments: ___

___

___

PLEASE RETURN SURVEY TO:

George Medley
MAURER ENGINEERING INC.
2916 West T.C. Jester
Houston, TX 77018-7098
Fax No.: 713/683-6418

Figure 5-3. Project Questionnaire (Page 2)

Additional Data

Data from the other published sources described earlier in this section concentrated on historical descriptions and forecasts of drilling activity, with particular emphasis on gas wells. The number and type of wells drilled each year, target formations, drilling activity by region, depth of wells being drilled, and any available cost data were included. This information was gathered for oil and gas wells, dry holes, and specifically those drilled underbalanced, where available.

Through contact with service companies and oil and gas operators, data were collected on numbers and percentages of wells drilled underbalanced. Because this technology has only recently seen increased interest, much of the data specific to underbalanced drilling operations were estimates only.

Survey Response

A questionnaire was originally sent to 63 individuals representing DEA participants involved in drilling operations in the United States. As other players in underbalanced technology were identified, they were added to the survey population, primarily through personal contact over the telephone. By the end of the survey, contacts had been made with 75 individuals representing 66 companies.

Eight of these companies reportedly had no U.S.A. domestic operations in the past year, and nine of these companies were either equipment manufacturers or service companies whose service does not depend on whether or not underbalanced techniques were being used. These were unable to provide much meaningful data, leaving the project with 49 companies having the potential to provide meaningful data concerning the domestic market for underbalanced drilling.

A total of 30 companies responded to the survey, representing 61% of the 49 potential respondents. After removing those responses that could not provide meaningful data (i.e., incomplete or no data, or responses from vendors that do not track underbalanced operations), 24 useful responses remained, representing 49% of the potential useful responses.

5.3 QUESTIONNAIRE ANALYSIS AND PROJECTIONS

5.3.1 Analysis of Questionnaire Responses

Question 1. Usage of Lightweight Fluids

The first question was an estimate of the total number of wells and wells drilled with lightweight fluids in 1994 and 1995 and projected to be drilled in the next 2, 5, and 10 years. This question was included in an attempt to determine the level of underbalanced drilling currently being performed with lightweight fluids and to project future growth.

Responses to question 1 were received from 17 operators, including small independents and major oil and gas companies. These operators reported drilling a total of 1852 wells in 1994, and they expect to drill a total of 1773 wells in 1995.

These totals represent 7.4% of all wells drilled in the U.S.A. in 1994 and 7.9% of all wells expected to be drilled in 1995. Responding operators also reported drilling 5.5% of U.S.A. gas wells drilled in 1994, and will drill 6.6% of domestic gas wells in 1995.

These operators drilled 10% of their oil wells with lightweight fluids and 40% of their gas wells with lightweight fluids in 1994. The total lightweight fluid drilling represented 27% of their wells (Figure 5-4).

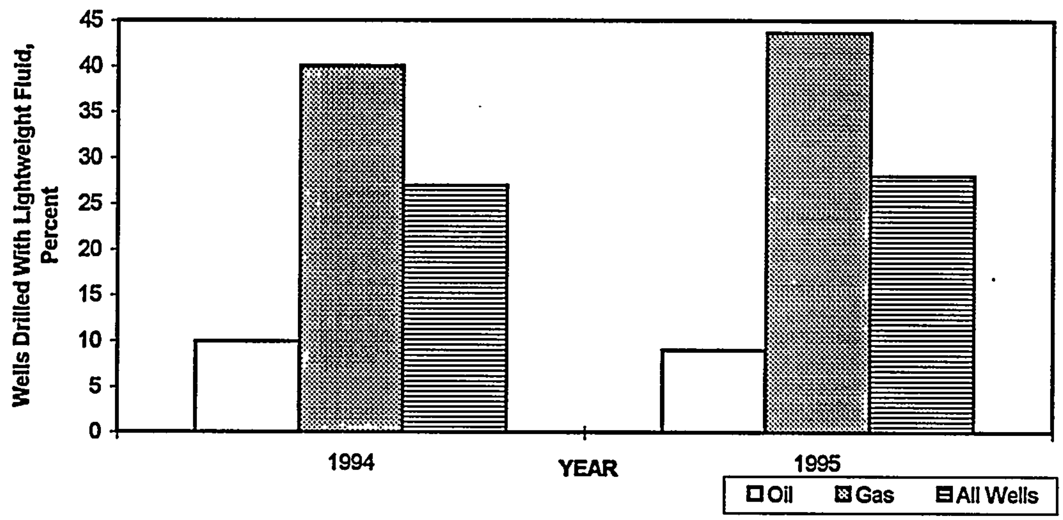

Figure 5-4. Lightweight Fluid Usage by Operators

Oil well drilling with lightweight fluids is projected to remain at about the same level in 1995. A slight increase in gas wells drilled with lightweight fluid is projected (up to 44% from 40%). Total lightweight drilling for these operators will increase from 27% to 28% (see Figure 5-4).

The reported use of lightweight fluids from questionnaire respondents is much higher than expected. It is believed that the results do not accurately reflect current lightweight fluid usage. Examination of the job titles of the individual respondents revealed that several of the questionnaires were forwarded within the surveyed companies to that person specifically responsible for lightweight fluid drilling. Their responses tended to portray a higher level of lightweight fluid drilling than is probably true for the industry as a whole.

The responses to this question were adjusted in an attempt to gain a more representative picture of current activity. This adjustment entailed removing the totals for those companies that reported drilling more than 80% of their wells with lightweight fluids. In addition, one company had a large volume of lightweight fluid wells concentrated in only one geographic area. This large volume of wells skewed the overall results heavily in favor of lightweight fluids. Another company notified us that their well count was incomplete; more than 85% of their gas wells were reportedly drilled with lightweight fluids.

The adjusted data set was used only to estimate the number of wells drilled in 1994 and 1995 with lightweight fluid, and to make low-case projections of lightweight fluid use in the future. This estimate was then compared to other data as a validity check.

When the potentially biased responses were backed out of the total, the average percentage of wells drilled with lightweight fluid for 1994 was 7.2%. For 1995, the average is expected to be 10.0%. These estimates still represent over 3.5% of all wells drilled in the United States. These results are in good agreement with another projection provided earlier to the DOE.

Carden reported in the *Technological Assessment of Vertical and Horizontal Air Drilling Potential in the United States*, the final report under DOE contract DE-AC21-92MC28252, that 12.7% of all U.S. drilling was done with air in the period 1991-1993. Smith Tool Company data for those three years indicate that the percentage of drilling done with air declined from 14.4% in 1991 to 7.4% in early 1993.

The adjusted activity summary for this survey for 1994 is consistent with the numbers provided by Smith Tool Company for 1993. This serves as a measure of validation to the survey results. As interest in lightweight fluids and underbalanced drilling has increased in the last year, an increase in the well percentage from 7.2% to 10.0% in 1995 appears to be very reasonable. Additionally, the median response from both the adjusted survey of the operators and the survey of the service companies is that 10% of all wells drilled two years from now will be drilled underbalanced.

Responses were received from seven service companies, including three of the largest air drilling companies in the world, one major drilling fluid company, and a nitrogen provider. These companies reported a combined total of 976 wells drilled in 1994 and 1210 wells drilled in 1995. These totals represent 3.9% and 5.4% of the total wells drilled in the United States in 1994 and 1995, respectively.

Not surprisingly, considering the source, 93% of these wells were drilled using lightweight fluids (i.e. air, foam, or mist). Because of this, responses from the service companies were not used to make any projections or forecasts of wells to be drilled with lightweight fluids.

Question 1 also asked for an estimate of the percentage of wells to be drilled underbalanced in two years, in five years, and in ten years. The responses to this question were used with other data to project the potential market for lightweight fluids.

Operators were more optimistic in their projections than the service companies, and their responses tended to be more consistent. Figure 5-5 shows their median estimated growth in underbalanced drilling. The percentage of underbalanced wells is estimated to grow from current levels to 15% of all wells by 1997. The growth is projected to continue to 20% of all wells by 2000 and to 30% by the year 2005.

The projected growth is primarily being driven by increasing concern with formation damage, potential for increased rate of penetration, and the ability to reduce lost circulation in depleted reservoirs. The first driver will result in increased profit, while the two other large drivers act to reduce cost.

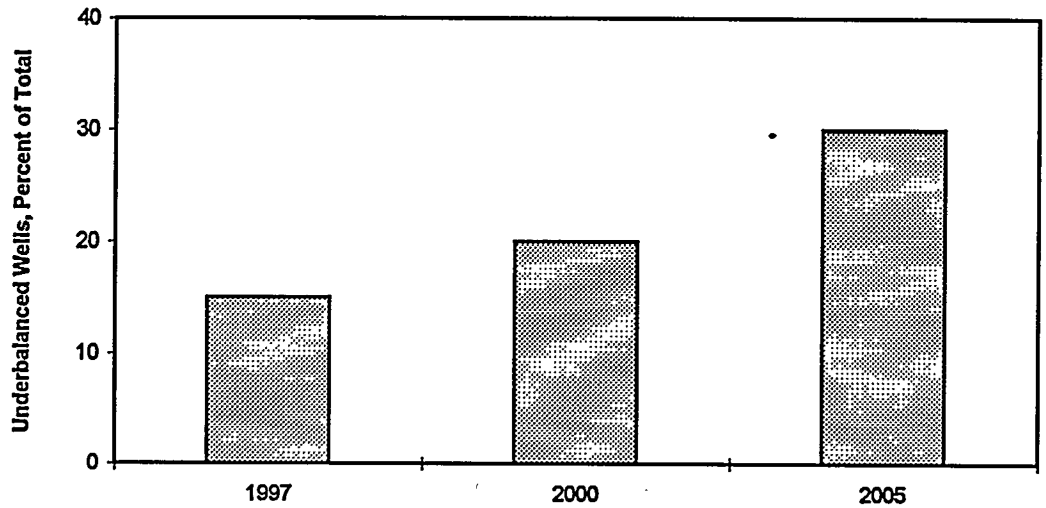

Figure 5-5. Underbalanced Drilling Growth (Operators)

Estimates for underbalanced drilling growth based on the average operator were even more optimistic; their average estimated underbalanced drilling utilization for the year 2005 was nearly 37%. The median growth figures probably represent a more balanced picture of expected growth.

The service companies as a whole were much more conservative in their growth estimates. Only three of the seven respondents ventured to guess future underbalanced drilling levels, and their median estimate was lower: underbalanced drilling will grow from current levels of 10% of all wells to 18% in the next ten years. Because of the low response rate to this question among service companies and their generally more conservative approach, less weight was given to this estimate in the final analysis.

All available equipment provided by the responding service companies for lightweight fluid drilling is currently in use in the field. Without exception, the air-drilling specialist companies reported a 100% equipment utilization. They are currently (July 1995) struggling to meet the demand, and they are reluctant to expand their equipment inventories because of the depressed industry market in general over the past 9-10 years. Limited equipment availability is most likely driving the pessimistic response from the service companies. Demand will be high, but supply will limit the application of underbalanced technologies, at least for the near term.

Question 2. Drilling Conditions Where Lightweight Fluids are Used

The second question asked the respondent to give an estimate of percentages of different drilling conditions they generally encounter. The choices of reservoir types and drilling problems included those that are generally conducive to drilling with lightweight fluids. The purpose of this question was to determine as completely as possible what percentage of reservoirs are potentially available for lightweight fluid drilling, without regard to whether or not they are currently being drilled with lightweight fluid.

Figure 5-6 shows the ranking of drilling conditions by responding operators.

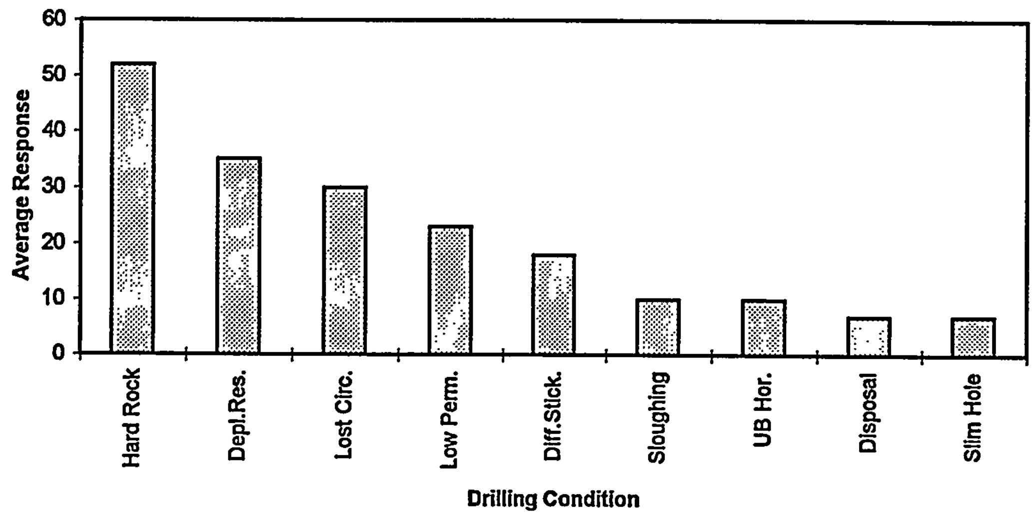

Figure 5-6. Underbalanced Drilling Conditions (Operators)

Operators reported that an average of 52% of reservoirs they operate are in hard rock. Hard-rock reservoirs are typically favorable to lightweight fluid drilling. These reservoirs have often been drilled with air or aerated fluids because of the increased rates of penetration that can be achieved.

The operators reported that 35% of their reservoirs were pressure depleted. This condition is also conducive to lightweight fluid drilling. Using air or aerated fluids allows the reservoir to be drilled underbalanced, which prevents fluid invasion into the reservoir. This in turn prevents formation damage, differential sticking, and lost circulation. An average of 30% of the reservoirs reported are likely to have lost-circulation problems.

The fourth largest category of conditions encountered by the responding operators is low-permeability gas reservoirs. These reservoirs, accounting for 23% of those available for drilling by the operators, are candidates for lightweight fluid drilling because an underbalanced condition while drilling is less likely to encounter formation fluids entering the wellbore. If an influx does occur, it is more likely to be small and easily handled. Low-permeability reservoirs are also typically harder rock, which again is a good application for lightweight fluids.

Other drilling conditions that are good candidates for lightweight fluid drilling were reported with lower frequencies by the operators. Those reservoirs prone to differential sticking represent 18% of available reservoirs; those with sloughing shales and where underbalanced horizontal drilling has been done account for 10%; reservoirs in areas with fluid-disposal problems and slim-hole applications represent 7% of available candidates each.

Since the service companies responding were predominantly involved in air drilling, their responses were significantly different from the operators. On average, they reported virtually no reservoirs being drilled with lost-circulation problems, for low-permeability gas formations, with fluid disposal problems, or differential sticking (Figure 5-7). The areas of operation for the service companies are more limited in geography and in reservoir type. The dominance of air, mist, and foam drilling in their operations has eliminated or greatly reduced their exposure to several of the listed problems. In many cases, difficult reservoir types are being drilled, but it is not apparent to the service company because the problem has been solved through the use of lightweight fluids.

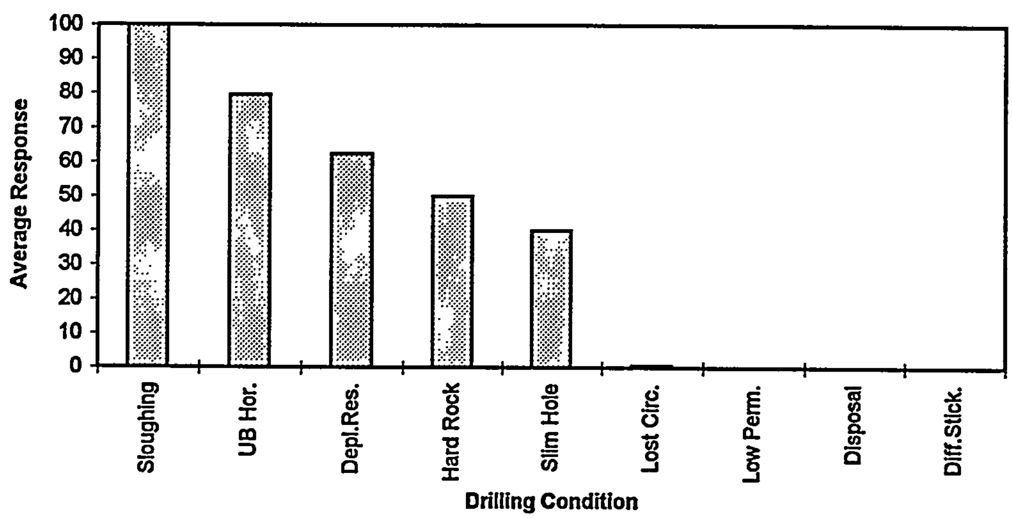

Figure 5-7. Lightweight Fluid Drilling Conditions (Service Companies)

Ranking Questions

Questions 3, 4, and 5 all instructed respondents to rank various advantages, disadvantages, and concerns associated with lightweight drilling fluids. These responses can be used to determine what types of lightweight fluids and associated products should be marketed and how best to market them.

The responses to these three questions were evaluated in two ways. First, a total score was given for each item, determined by simply adding all responses for that item. Since all rankings were based on a low number ranking being of more importance (i.e., 1=most important problem etc.), the lower the total score, the more significant or important that item is perceived to be. In cases where a particular item was not ranked by a respondent, suggesting very little or no importance to that individual, the item was assigned a score equal to the highest possible rank plus 1.

The responses were also evaluated was on the basis of the percentage of respondents assigning a particular item high importance. High importance was defined as an assigned ranking of 1 or 2. In this way, items ranked by only a few respondents, but considered to be very important to them, would not be lost within the overall larger body of data. For instance, an item ranked as 1 or 2 by 40% of the respondents, but not ranked at all by the remaining respondents, might receive a higher overall score than an item ranked 5 or 6 by all respondents. The former item, however, might be of greater importance, and should be considered.

Question 3. Advantages of Lightweight Fluids

Each respondent was asked to rank several well known advantages of lightweight fluids. The advantages ranked were: environmental benefits, increased rate of penetration, increased bit life, reduced differential sticking, reduced formation damage, reduced lost circulation, and other advantages. These responses will help determine which lightweight fluid products might already have strong market acceptance.

Figure 5-8 shows that operators as a group regard reduced formation damage as the biggest advantage to using lightweight fluids. Increased rate of penetration is considered the next best advantage, followed by reduced lost circulation.

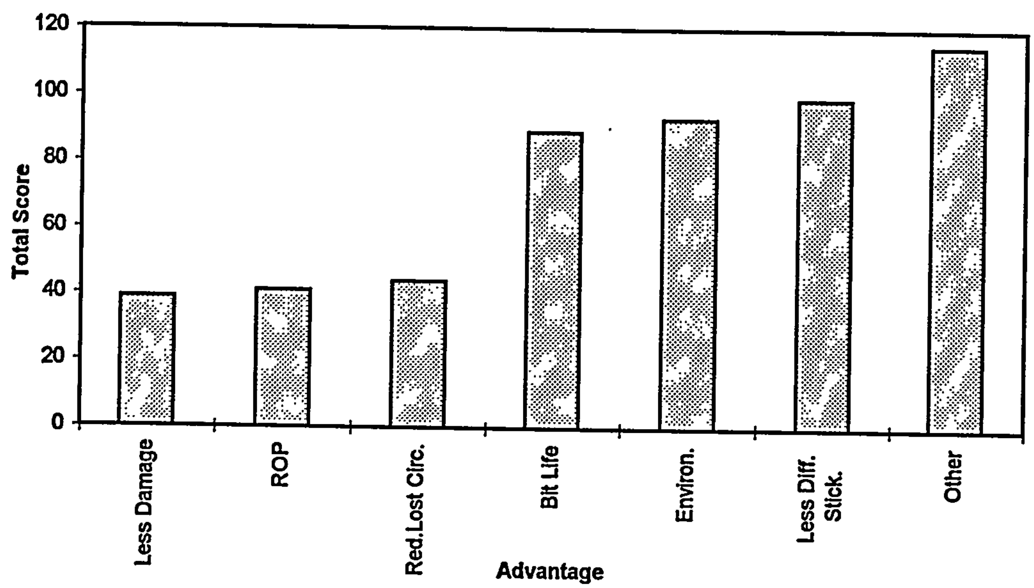

Figure 5-8. Advantages of Lightweight Fluids (Operators)

Historically, rate of penetration increases possible with lightweight fluids have been considered the greatest advantage. This shift toward strong concern about formation damage may reflect the largest potential market for lightweight fluids. This will open up areas to lightweight fluid drilling that have never seen the application of that technology. This is especially important considering that 35% of reservoirs drilled by these operators are pressure depleted (see Question 2).

The total ranking score increases significantly when moving from reduced lost circulation to increased bit life (see Figure 5-8). This trend reflects a large decrease in the level of importance of bit life and other advantages. Environmental benefits, reduced differential sticking, and other advantages were also not reported as having much importance to the operators.

The variation in level of importance between these items is even more apparent in Figure 5-9. These data, representing the percentage of respondents giving a rank of 1 or 2, show that 50% or more consider reduced formation damage, increased rate of penetration, and reduced lost circulation to be of high importance. Other advantages were considered to be highly important to only 7% or less of the respondents.

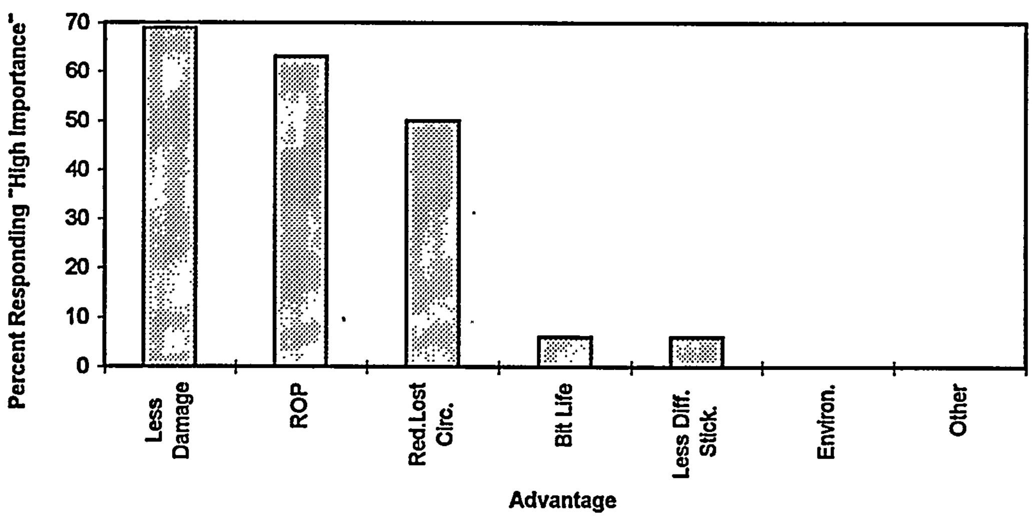

Figure 5-9. Highly Important Advantages of Lightweight Fluids (Operators)

Service companies, based on summed rankings given to each option, ranked as most important the same three items as the operators (Figure 5-10). However, they indicated that increased rate of penetration is more important than reduced formation damage.

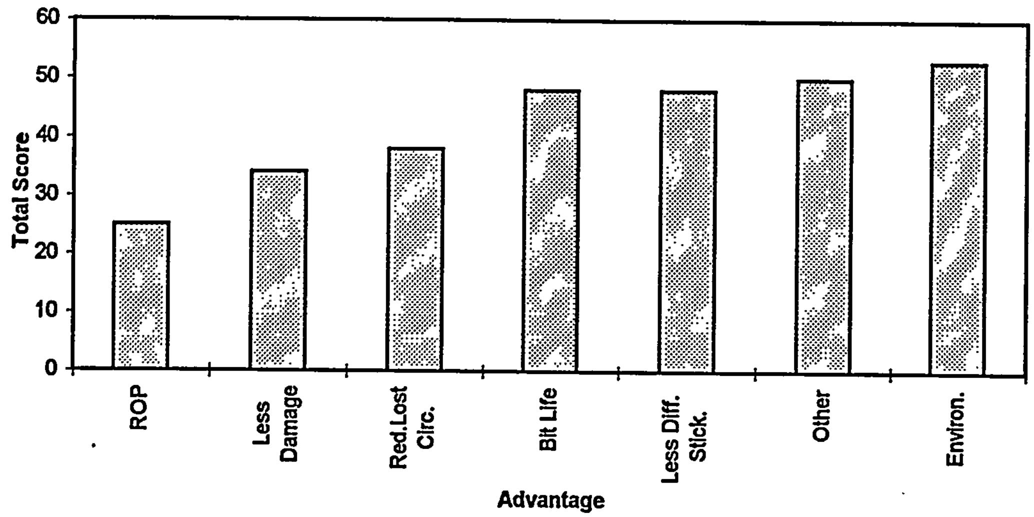

Figure 5-10. Advantages of Lightweight Fluids (Service Companies)

This trend is more evident in Figure 5-11, where the percentage of service companies ranking each advantage as 1 or 2 is shown. Rate of penetration was highly important to twice as many service companies as was reduced formation damage. Otherwise, these rankings are very consistent with those of the operators.

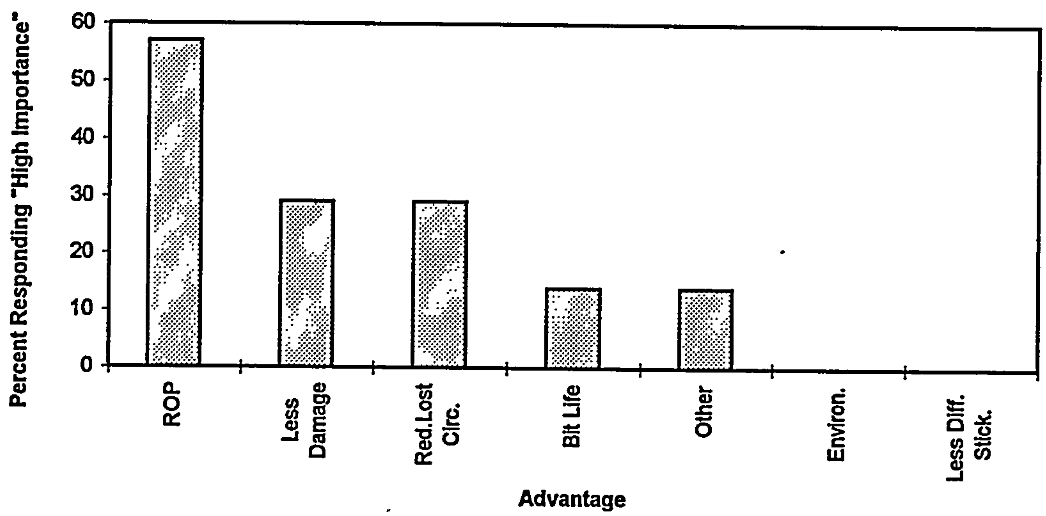

Figure 5-11. Highly Important Advantages of Lightweight Fluids (Service Companies)

Question 4. Disadvantages of Lightweight Fluids

Question 4 asked respondents to rank the disadvantages of air, mist, foam and aerated fluids. Options included corrosion, difficult hydraulics calculations, downhole fires, inability to handle fluid influxes, high chemical costs, high nitrogen cost, hole erosion, inability to recirculate foam, inability to use a conventional MWD, and other disadvantages. These responses will help target areas most in need of research and development to make lightweight fluids marketable.

The inability of lightweight fluids to effectively handle formation fluid influxes is the primary limitation of using these fluids, according to operators' summed rankings (Figure 5-12). This indicates a good potential market for lightweight fluids that are not adversely affected by the invasion of other fluids.

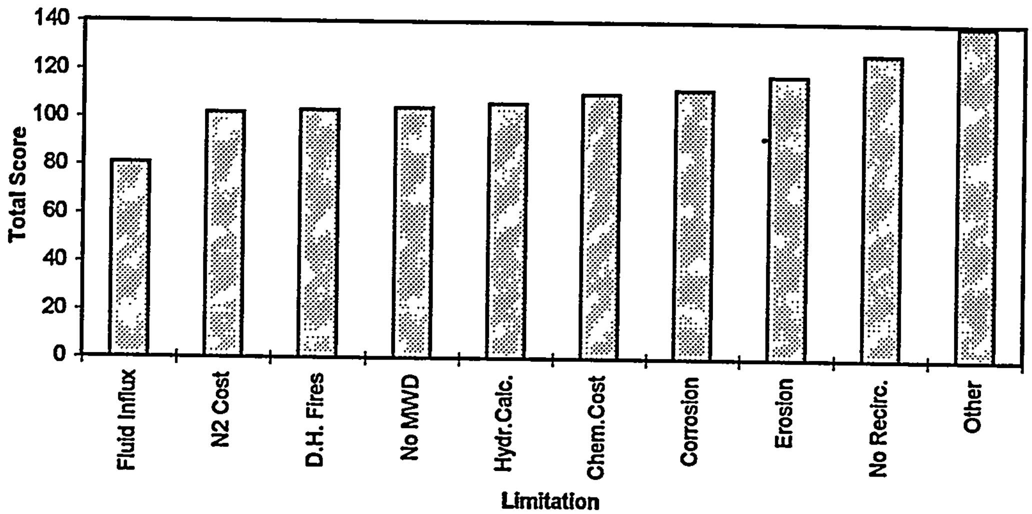

Figure 5-12. Lightweight Fluid Limitations (Operators)

Other disadvantages of lightweight fluids were indicated as having about the same level of importance to operators. However, based on the percentage of operators assigning each disadvantage a rank of 1 or 2 (Figure 5-13), in addition to problems with influxes, operators are most concerned about the inability to use conventional MWDs and the difficulty in calculating hydraulics accurately. Other problems had lesser levels of concern.

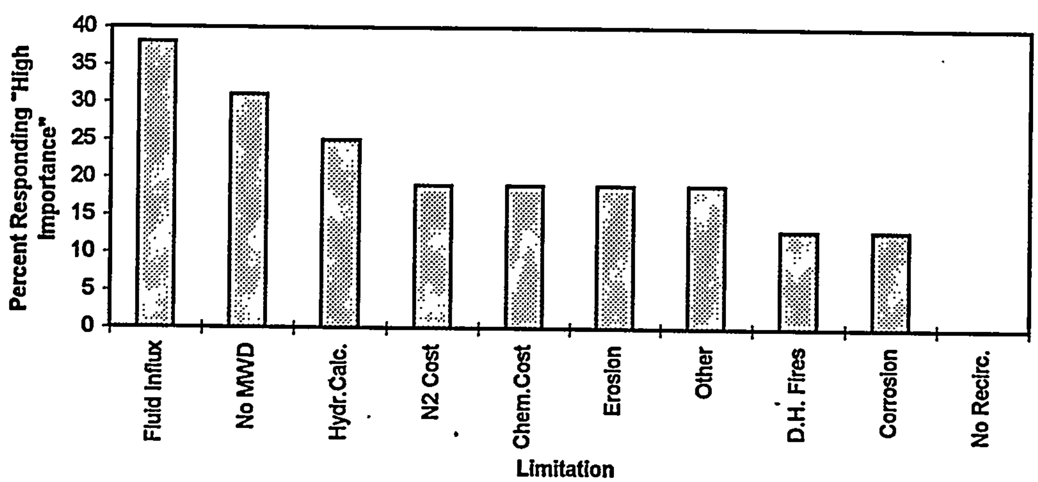

Figure 5-13. Highly Important Limitations of Lightweight Fluids (Operators)

The three most significant problems operators have with lightweight fluids are all addressed by the development work undertaken in this project. The Lightweight Solid Additive fluid tested and described in Chapter 4 would help overcome contamination problems associated with influxes and should allow the use of conventional MWDs in underbalanced drilling. The problem of difficult hydraulics calculations is directly addressed by the FOAM computer model developed as part of this project (see Chapter 3).

The service companies expressed more concern with direct cost-related items than with operational concerns. As Figure 5-14 shows, their greatest concern was with corrosion, closely followed by nitrogen cost and high chemical cost. The difficult hydraulics calculations involved were also of high concern.

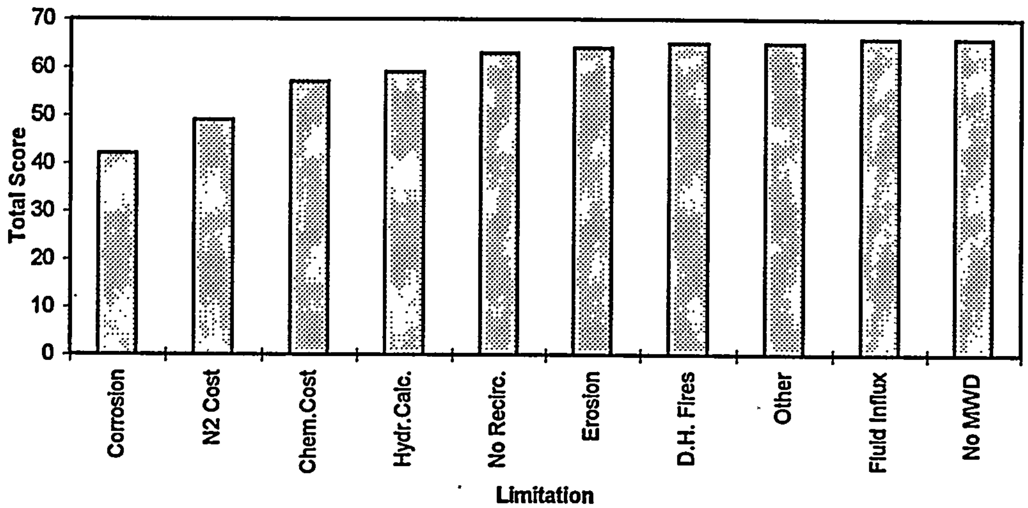

Figure 5-14. Disadvantages of Lightweight Fluids (Service Companies)

These results point out a need to develop tools and techniques to reduce corrosion and the high costs associated with controlling it, as well as ways to cut costs in general.

Question 5. Hindrances to Use of Lightweight Fluids

The fifth question on the questionnaire asked respondents to rank the reasons why lightweight fluids are not used more in their operations. The barriers to use that were listed included economics and high cost, hole instability, inexperienced personnel, limited equipment availability, no planning tools, unfamiliarity with lightweight fluids, well-control concerns, and other reasons.

Unfamiliarity with lightweight fluids and the perception of high cost and/or poor economics related to lightweight fluid drilling were the two primary reasons operators gave for not using lightweight fluids more often (Figure 5-15). Inexperienced personnel and hole instability concerns also ranked as being relatively important.

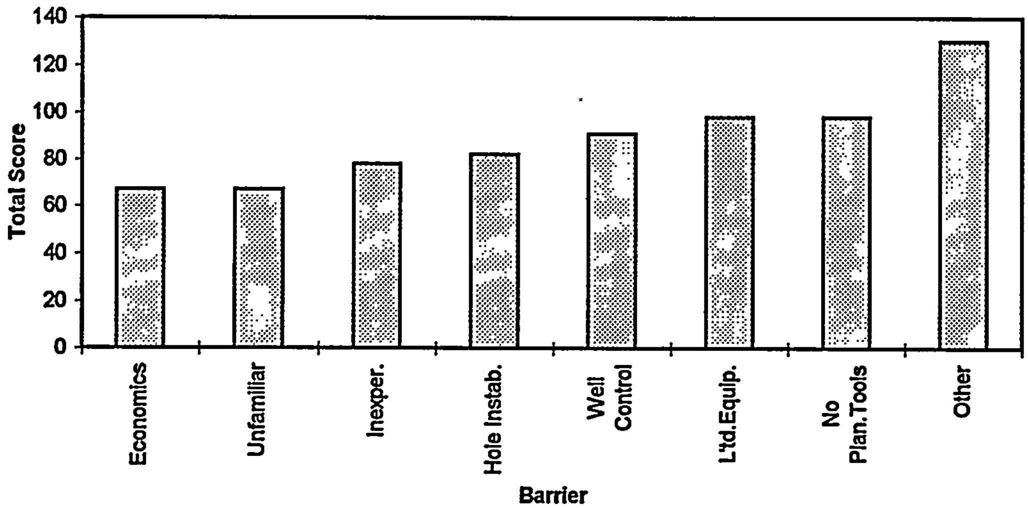

Figure 5-15. Reasons for Not Using Lightweight Fluids (Operators)

These summed rankings point out a real need for increased training and additional information and technology transfer throughout the industry in the areas of lightweight fluids and underbalanced drilling.

Hole-instability problems is the primary technical reason mentioned for low utilization of lightweight fluids. This result should be investigated further and validated to determine whether this is only a perception or is fact. The response to survey question 2 indicated that only 10% of reservoirs being drilled have problems with sloughing shales. Tectonic hole-stability problems may be the greatest concern being expressed by this response.

The ranking of highly important reasons (i.e., those given a rank of 1 or 2) for not using these fluids is essentially identical to the overall ranking score for these items by the operators, as seen in Figure 5-16.

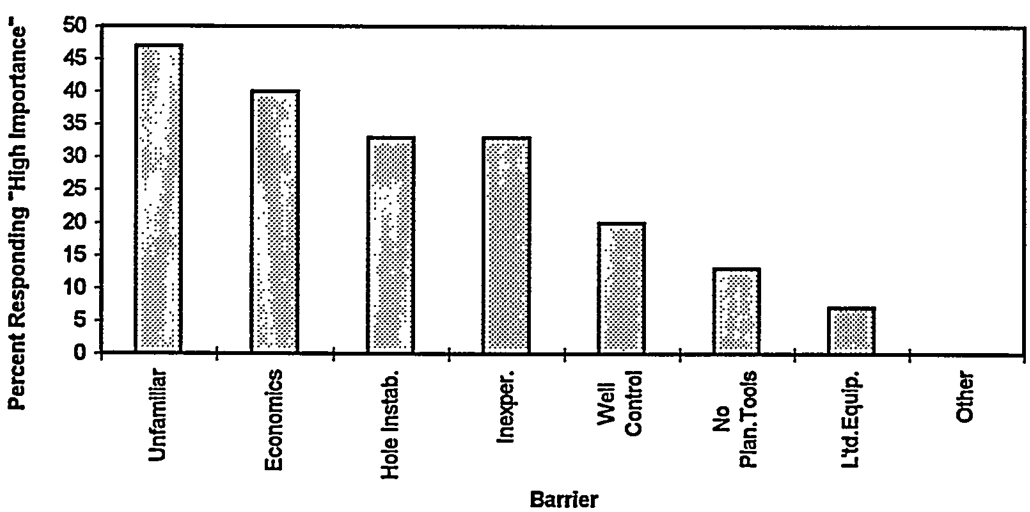

Figure 5-16. Highly Important Barriers to Lightweight Fluid Drilling (Operators)

The service companies also ranked high cost, unfamiliarity, and inexperienced personnel as important reasons that lightweight fluids are not used more for drilling (Figure 5-17). However, the primary reason given for not using lightweight fluid more often is limited equipment availability.

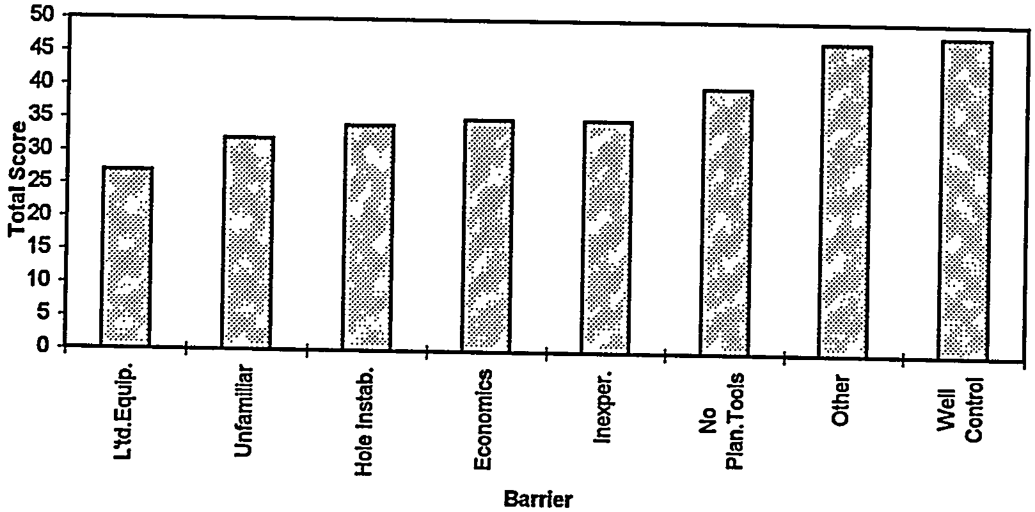

Figure 5-17. Barriers to Increased Usage of Lightweight Drilling Fluids (Service Companies)

Limited equipment availability will became a larger problem in the future as the demand projected by service companies and operators alike increases for lightweight fluids. This is already a significant problem in some regions. One service company in the Rocky Mountains reports that for the first time spud dates are being determined by the availability of air-drilling packages. All available equipment owned by this company is currently being utilized, and all equipment they manufacture is being put into service immediately. This trend is the primary factor that may limit the expansion of under-balanced drilling with lightweight fluids.

Question 6. Potential for New Incompressible Lightweight Fluid

Question 6 mentioned the incompressible lightweight solid additive (LWSA) fluid being tested under this project, and asked respondents whether or not they would use a fluid of this type if it were available. They were also asked how many wells per year might be candidates for this fluid, where the wells are located, and what depths would be drilled to with the fluid.

Figure 5-18 shows that fully 50% of the operators said they would use an LWSA fluid. Another 44% said they would possibly use the fluid, depending on circumstances. Overall, 94% of the operators were willing to consider using a fluid like that being developed as part of this project.

More specifically, operators reported that they currently have a total of 97 wells that are candidates for this LWSA fluid.

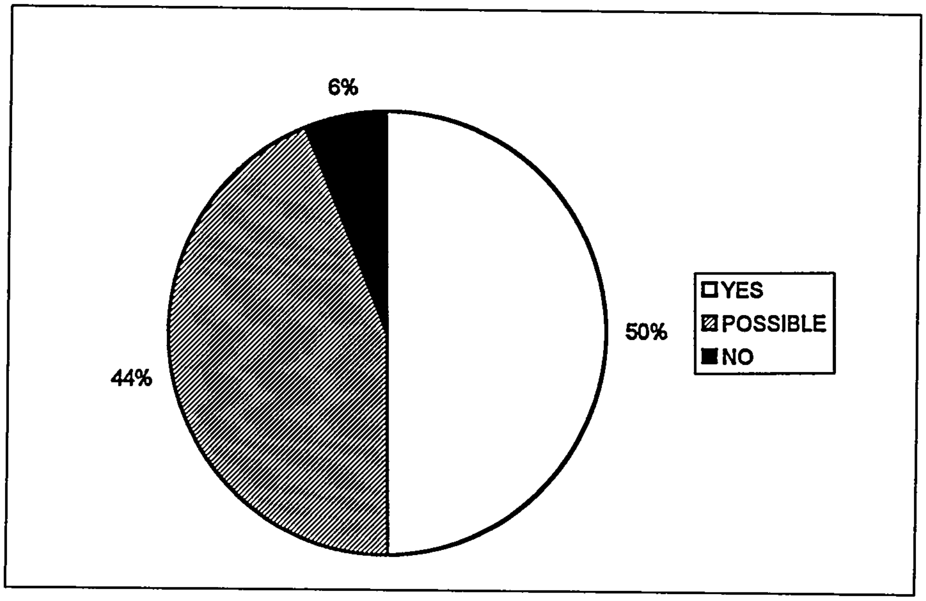

Figure 5-18. Operators Willing.to use an LWSA Drilling Mud

Even more surprisingly, out of five service companies that responded, two said they would be willing to try the fluid (Figure 5-19). The service companies stated they have approximately 110 wells currently that are candidates for using this fluid.

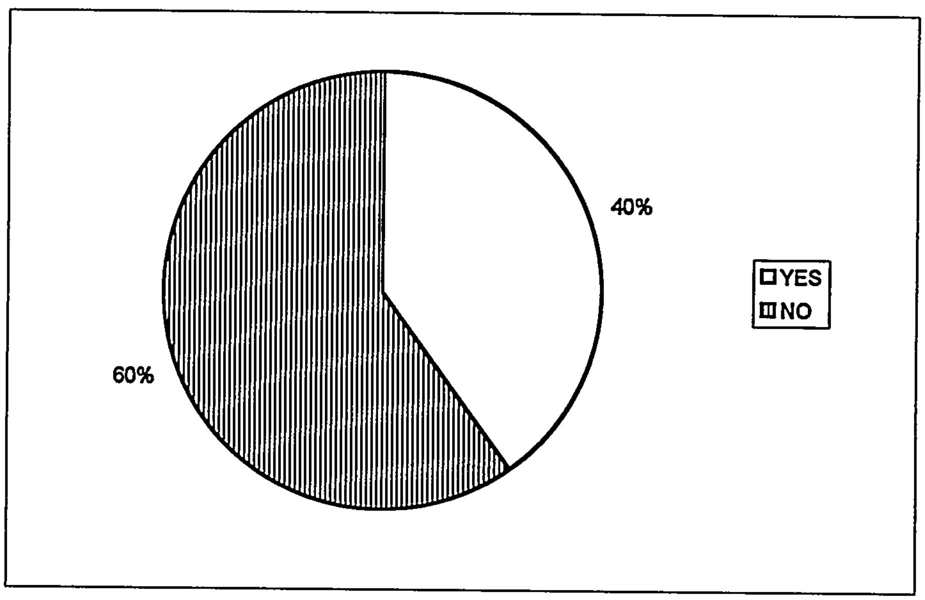

Figure 5-19. Service Companies Interested in Using an LWSA Drilling Mud

The total number of candidates identified by the operators and service companies for possible application of an LWSA drilling fluid is 207 wells. Assuming no overlap in projected candidates, this represents 11.7% of all wells to be drilled by the operators in 1995. This represents a substantial market for a product that is not yet commercially available.

Reported regions where the LWSA fluid could find potential use include the Rocky Mountains, the Permian Basin, Oklahoma, Arkansas, Northern Louisiana, and Central Texas. The depths of application listed ranged from 2500 to 22,000 ft.

5.3.2 Projected Drilling Activity

A final step was to use results from the questionnaire and other sources to develop a forecast of underbalanced drilling activity over the next decade. To project the use of lightweight fluids in drilling, it was first necessary to estimate the total number of wells that will be drilled. Without exception, respondents indicated that lightweight fluid and underbalanced drilling will form a subset of total drilling, that is, no increase in overall well counts are expected because of underbalanced drilling. Instead, underbalanced drilling will expand by replacing wells that might have been drilled conventionally.

No sources of projections for underbalanced drilling forecast prior to this project were found. This effort represents the first known market projection for underbalanced drilling in the United States that is publicly available.

Several sources of data were used to project the overall level of drilling, as mentioned previously. A primary source was a detailed projection by the Gas Research Institute in *The Long Term Trends in U.S. Gas Supply and Prices: 1994 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010.* Because GRI's projection was made in May 1994, the prediction for 1994 needed to be compared to actual well counts. In addition, since the projected number of wells for 1995 was optimistic compared to actual experience so far this year, adjustments to the projected drilling levels for 1995 through 2005 were deemed necessary.

GRI projected that 24,973 wells would be drilled in the U.S.A. in 1994. *Petroleum Engineer International* magazine, in January 1995, listed the 1994 well count as 27,036. As of July 31, 1995, *Oil & Gas Journal* had a well count for 1994 of 22,700; Petroleum Information, an independent firm specializing in petroleum industry data, had a count of only 17,428. In light of this variation, the GRI well count for 1994 was used as a base level for all projections.

For 1995, GRI projected a total of 27,574 wells to be drilled. *Oil & Gas Journal* (July 31, 1995) projected that 21,900 wells will be drilled in 1995. In addition, *Oil & Gas Journal* notes that the Baker Hughes weekly rig count for the first half of 1995 averaged 666, which is 13% lower than in the first half of 1994. They then projected a year-end average of 730 rigs, down 5.8% from 1994.

The DOE Energy Information Administration predicts that the average rig count for 1995 will be 10.5% lower than the 1994 level. This would yield an average of 693 rigs, very comparable to the *Oil & Gas Journal* prediction. The Energy Information Administration computer model predicts that the rig count for 1996 will rise by 5.8%.

Assuming that the decrease in rig count will be mirrored by a corresponding decrease in total well count, the final total well count for 1995 will be 22,360 wells, based on the industry well count for 1994. This prediction is within 2% of the *Oil & Gas Journal* projection.

The number of wells projected for 1996 using this same method is 23,650. From 1997 to 2005, the GRI total well growth rate projections were used. Combining these data yields the well projection shown in Figure 5-20.

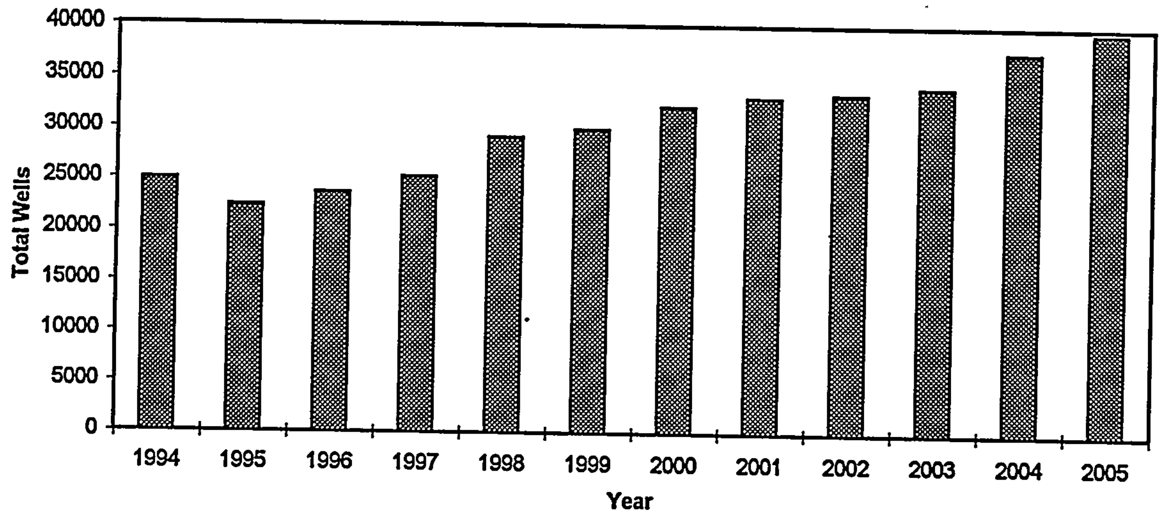

Figure 5-20. U.S.A. Drilling Activity—Total Wells Drilled

Lightweight Fluid Drilling Activity

The number of wells projected to be drilled with lightweight fluids is based on the results of the questionnaire portion of the industry survey. An analysis of responses to Question 1 concluded that the percentage of all wells drilled with lightweight fluids for 1994 and 1995 is 7.2 and 10.0%, respectively. A projected increase in underbalanced drilling (the prospective market for lightweight fluids) was also reported, as determined from the median responses of the operators.

The base case for the projection of lightweight fluid use is a combination of the median response estimate of growth in underbalanced drilling in Figure 5-5 and the projected total well count in Figure 5-20.

Low and high projections were also developed. All cases are based on the projected total well counts (see Figure 5-20). The differences between the cases are due to differences in projected growth rates of underbalanced drilling.

The low-case projection uses a median projected growth rate based only on operators currently drilling less than 85% of their wells with lightweight fluids (i.e., the adjusted response described under Question 1 previously). The low-case projected use of lightweight fluid drilling as a percentage of all wells is 10, 15, and 25% for the years 1997, 2000, and 2005, respectively.

The high-case projection uses the unadjusted average projected growth rates provided by operators responding to the survey. These rates project that, in 1997, 2000, and 2005, 17.1, 27.4 and 36.9%, respectively, of all wells drilled in the U.S.A. will be drilled underbalanced.

Figure 5-21 shows that the number of wells drilled with lightweight drilling fluids will increase from 2236 wells in 1995 to almost 12,000 wells per year by 2005 (base case). The potential market for lightweight drilling fluids has an upside of nearly 15,000 wells per year within the next ten years.

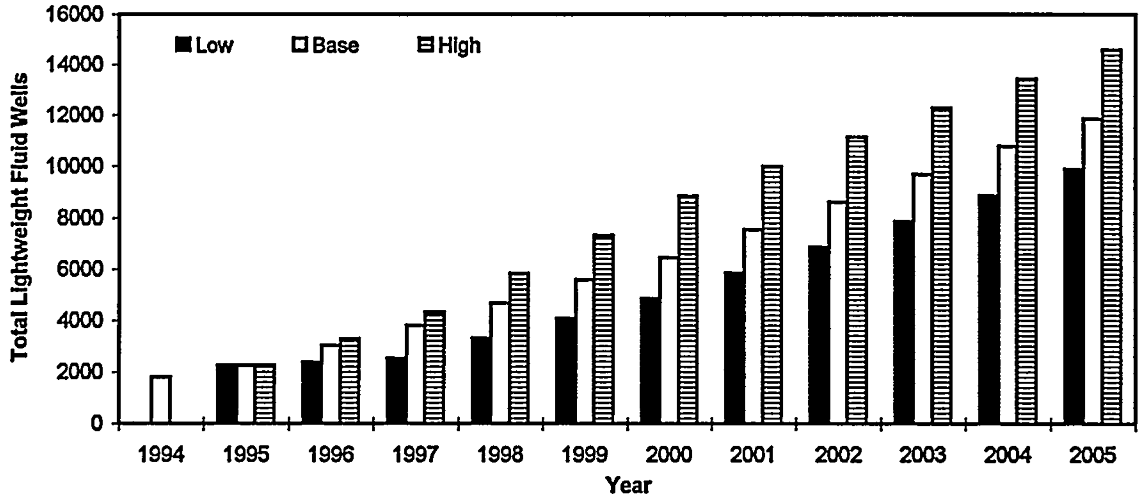

Figure 5-21. Growth of Lightweight Fluid Use in the U.S.A.

Gas Well Projections

GRI forecast the number of gas wells to be drilled in their 1994 baseline projection. The same ratio of gas wells to total wells was used in the present study to project the number of gas wells to be drilled with lightweight fluids. The forecast (Figure 5-22) predicts that the number of gas wells drilled with lightweight fluids will increase over the next ten years from the current 662 to nearly 3000 per year, with a high-side potential of over 3600 per year.

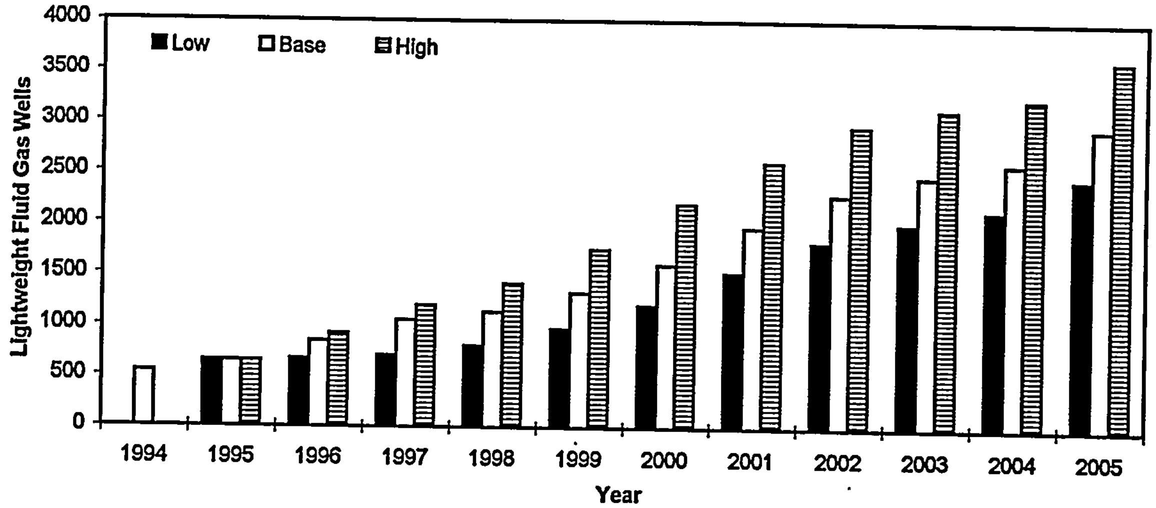

Figure 5-22. Gas Wells Drilled With Lightweight Fluids

The gas well projection is probably conservative. Questionnaire responses show that a larger percentage of gas wells than oil wells are drilled with lightweight fluids. One reason for this trend is that any gas produced during underbalanced drilling can be flared. Handling produced oil on a drilling site is much more difficult.

5.4 MARKETING PLANS

5.4.1 FOAM Model

Maurer Engineering Inc. (MEI) will be the primary distributor of the FOAM computer software. MEI will begin making this software available in its final form as soon as the Department of Energy gives the formal approval to do so.

MEI's direct clients include eight of the top ten oil and gas operating companies in terms of wells drilled in the United States. Its client list represents 55% of the net wells drilled in the United States in 1994 by the 300 largest operators, as reported in the *Oil & Gas Journal* (September 5, 1994).

Through past work for the DOE, GRI, and the Drilling Engineering Association (DEA), MEI has developed a network of thousands of contacts in hundreds of companies who are directly involved in drilling oil and gas wells. These contacts represent a large portion of the market base for this software.

In the past, MEI has developed and distributed more than 20 other software products, most having a structure similar to that of the FOAM model. Most of the software distribution has taken place through DEA-sponsored projects. The DEA will be the primary marketing avenue for the FOAM computer program.

Initial distribution will take place through the companies currently participating in the MEI DEA projects. All participants in the DEA projects involving horizontal, slim-hole, and coiled-tubing drilling will be given a copy of the FOAM model.

Distribution will be made to the widest audience possible, as quickly as possible. The FOAM model will be demonstrated at a minimum of two industry-wide technical conferences. At these demonstrations, anyone interested in obtaining a copy of the program will be encouraged to contact MEI.

MEI will distribute the FOAM model to all interested parties who request it for a fee of $50-100. This minimal charge will cover the costs of reproduction, the user's manual, and shipping and handling.

Dynamic software development demands a high level of program maintenance. The MEI staff will be available to maintain and update the FOAM software with regard to both technical content and program design and operation. The FOAM program will be maintained and updated as needed.

MEI also maintains the capability to provide training in the most effective use of the software. Training in the use and application of the FOAM program will be developed by MEI. A school on underbalanced drilling will be developed, with a major portion of the school built around the lightweight fluid model. This training will be made available through on-site seminars in users' offices or at MEI facilities in Houston.

MEI will retain the exclusive rights to the source code for this model for five years, with the exception that the United States government will be able to use it for governmental purposes.

The FOAM computer model will have wide application, not only in the drilling industry, but also as a tool for workovers done with foam fluids. MEI will investigate applications for the FOAM model in the well workover and clean-out industry. One avenue to expand this market for the program will be through the Completions Engineering Association (CEA).

5.4.2 Lightweight Solid Additives

Plans for marketing the lightweight solid additive (LWSA) fluid are still being developed. The concept of an incompressible fluid has been introduced to the general public through presentations at the 1995 DOE Contractors' Review meeting and the Society of Petroleum Engineers annual meeting (October 1995).

These LWSAs have been used in the industry for years, although not for this application. These additives are, as a consequence, not patentable. This makes effective marketing more difficult. MEI will continue to work with our subcontractors to develop a unique procedure related to LWSA fluids that could result in a patentable product.

MEI and manufacturers' representatives have met several times. Distributors for the LWSA are in place around the world. Supply should not be a problem, since the additives can be stored and transported in a variety of containers.

Even though the LWSAs and fluids look promising in the laboratory, they are as yet unproven for use in the proposed application. Field testing is schedule to begin in the Fall 1995. Results of field tests will help determine the marketability of the product.

Three options exist for marketing lightweight solid additive fluids. MEI is pursuing each of these:

1. MEI might seek the involvement of a major mud company. The mud company will act as distributor and license holder for the technology. Specialized applications and handling techniques will be revealed only to this license holder.
2. MEI will develop a process for handling or mixing the additives to make a drilling fluid with optimum properties. Other processes with the potential for patents include recycling and re-using the additives, proper application of the fluid, and rheology control techniques.
3. MEI might form a new company to distribute the product. The new company will act as licensee to apply the technology in the right reservoir and under the proper conditions. New techniques for achieving optimal performance from the additives will be developed.

Additional market potential for these fluids also exists in the well workover industry. This potential will be investigated similarly to that of the FOAM model.

5.5 ECONOMIC ANALYSIS

5.5.1 FOAM Model

The economics of drilling with air, mist, and foam requires a multifaceted analysis. Initial responses from most potential users are that foam drilling costs more than conventional drilling. This appears to be the case at a macroscopic level, especially when a conventional drilling rig is used. The necessary compressors, boosters, and liquid injection pumps must be rented at additional costs ranging from $2500-$4500/day. In addition, a foam drilling equipment engineer must be hired.

However, foam equipment often displaces conventional mud drilling equipment and the cost of the conventional mud system. Fixed costs for a conventional mud system can range up to $20,000. Daily costs range from $800 to $3500/day, depending on the type of conventional mud system employed.

Drilling with foam can cost as much as $3700 a day more than with conventional muds, or it may be less expensive. A typical estimate for foam drilling costs is $2500/day more expensive than conventional.

These added costs can only be justified if savings can be accrued elsewhere in the operation. Fortunately, this is normally easily done.

Since rates of penetration with lightweight fluids can range from 2 to 10 times faster than with conventional muds in the same hole, the entire drilling operation will take much less time. Drilling operations can cost $175/hour (low side) to as much as $1000/hour (high side) for wells where foam drilling may be applicable. In the low-side case, more than 11 hours per day would need to be saved to justify drilling with foam. If the penetration rate is 10 times faster, these savings would be attainable.

In the high-side case, only 2 hours per day must be saved to justify foam drilling. Even if penetration rates increase only 10%, the extra costs will be offset.

Other considerations for air drilling are reductions in formation damage and hole trouble. If the well productivity is increased only slightly because there is no fluid invasion into the reservoir, foam drilling can be justified. Likewise, the elimination of lost-circulation or differential-sticking problems can justify the use of foam.

5.5.2 Lightweight Solid Additive Muds

Many factors impact the economic viability of hollow glass sphere (HGS) muds. The cost of the mud itself is the most obvious factor, but sphere recoverability, increased penetration rates and well productivity will also affect economics. HGS muds could be highly competitive with aerated and nitrified fluids, where compressor and nitrogen costs can be as high as $20,000 to $30,000/day.

A barrel of conventional 8.8 ppg PHPA mud costs between $1.50 to $2.50/bbl. At current glass sphere costs, a comparable barrel of HGS mud containing 30% spheres and weighing 7.0 ppg will cost $70 to $80/bbl, which is in the same range as mineral oil-base muds. It is possible that the cost of glass spheres can be reduced if they find widespread use in the petroleum industry and large quantities are purchased.

The range of expected sphere recovery for recycling (as described in Chapter 4) is 70 to 95%. Consequently, recycling the spheres can result in a net mud cost of $5.50 to $25.00/bbl, not including sphere recovery costs. If the use of HGS mud is compared to an oil-base alternative, HGS mud would have significantly less environmental cost than oil-base muds, since the glass spheres are inert and easily disposed.

A conventional PHPA mud system typically represents 8 to 15% of the total cost of drilling a well (exclusive of completion costs). In comparison, a mineral oil-base mud system often represents 20 to 25% of the total drilling cost. If the maintenance and make-up cost of HGS mud is comparable to a mineral oil-base system, the use of an HGS mud would increase the cost of a 20-day, 9000-ft TD, $400,000 well by $40,000 to $75,000, which is significantly less than the cost of compressors and nitrogen for air drilling.

If increased rate of penetration is the sole reason for underbalanced drilling, penetration would have to be increased by 23% in the typical well described above (i.e., 550 vs. 450 ft/day) for costs to break even. This magnitude of increase is well within the realm of possibility, since 2- to 10-fold increases in drilling rate have been observed in underbalanced drilling.

The potential for improved productivity in wells that are drilled underbalanced is also high due to the reduction or elimination of formation damage. A small improvement in productivity over the life of a well might easily justify the additional costs of using HGS mud.

5.5.3 Summary

Widespread use of foam and HGS mud technology for underbalanced drilling has the potential to significantly reduce capital expenditures and increase well productivity. In concert, these improvements will increase the net present value of drilling programs and extend the use of capital.

During Phase II of this project, multiple field performance tests will be conducted to verify the anticipated results. Data to be collected include drilling performance, early-time well productivity, and cost. Using those data, a comprehensive performance/economic analysis will be completed and reported in the Phase II final report.

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7. Acknowledgments

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