FILE COPY

8-C

ANNUAL REPORT

No. 3

DEVELOPMENT OF IMPROVED BLOWOUT PREVENTION PROCEDURES TO BE USED IN DEEP WATER DRILLING OPERATIONS

Submitted To

THE UNITED STATES GEOLOGICAL SURVEY

Department of the Interior

Reston, Virginia

PETROLEUM ENGINEERING DEPARTMENT

Louisiana State University

Baton Rouge, Louisiana 70803

August 15, 1981

ANNUAL SUMMARY REPORT

August 16, 1980 - August 15, 1981

Development of Improved Blowout Prevention

Procedures for Deep Water Drilling Operations

Contract No. 14-08-0001-17225, Mod. 2
Effective Date: August 23, 1978
Expiration Date: August 31, 1982
Funded Amount - $630,789.00

Sponsored by

The United States Geological Survey

The Department of Interior

Reston, Virginia

Principal Investigators:

William R. Holden, Professor
Petroleum Engineering Department

A. T. Bourgoyne, Professor and Chairman
Petroleum Engineering Department

Julius P. Langlinais, Assistant Professor
Petroleum Engineering Department

August 15, 1981

INTRODUCTION

One of the more expensive and potentially dangerous problems faced by the oil producing industry is the control of high-pressure formation fluids encountered while drilling for hydrocarbon reservoirs. When this control is not accomplished, a blowout may occur. A blowout is the uncontrolled flow of formation fluids from the well during drilling operations. When this uncontrolled flow discharges to the atmosphere or seafloor, it is called a surface blowout. The uncontrolled flow of fluids from one subsurface formation, through the wellbore, to a second, more shallow, subsurface formation is called an underground blowout.

Surface blowouts are extremely dangerous, frequently resulting in injury of drilling personnel, and almost always causing damage of drilling equipment and the environment. In some extreme cases, additional wells must be drilled in order to flood the high-pressure formation causing the flow. On the other hand, underground blowouts are not usually as dangerous as surface blowouts, but they are more common because the flow cannot be controlled by surface blowout prevention equipment. Usually subsurface control can be established only by sealing off the lower portion of the well. Many expensive wells have to be redrilled because of this phenomenon.

A threatened blowout or kick in a well occurs when the pressure exerted by a column of drilling fluid or mud decreases below the fluid pressure in a permeable formation which has been penetrated by a bit. Thereupon, formation fluid enters the well and displaces or kicks the drilling mud up the wellbore annulus until the flow at the surface is stopped by closing the BOP's. Before normal drilling operations can be resumed, the formation fluids must be removed from the well, and the density of the drilling mud in the well increased sufficiently to prevent their further influx. This procedure is accomplished by "circulating the well" against a back pressure provided by an emergency high-pressure flowline and an adjustable choke, using one of the several established operational procedures.

As the search for petroleum reserves has moved into the offshore environment, the blowout control problem has continued to increase in complexity. In addition, the difficulties in confining an offshore oil spill makes the environmental consequences of a blowout more important.

Most modern blowout prevention equipment was developed primarily for land-based drilling operations. With only minor modifications, this equipment has been applied to bottom-supported exploratory drilling rigs, such as jack ups and development rigs operating on an offshore platform. However, more significant modifications in blowout prevention equipment and procedures are required for floating vessels, which are used almost exclusively for deep water operations.

The first major modification for deep water operation was the location of the blowout preventer (BOP) stack at the seafloor rather than the surface. The current trend of the oil industry to much greater water depths (see Fig. 1) emphasizes the importance of the blowout control problem in floating drilling vessels. Future plans by the National Science Foundation[2] call for scientific ocean drilling in up to 13,000 ft of water during the next decade as part of their Ocean Margin Drilling program.

When compared to land-based drilling operations, floating drilling incurs more severe well-control problems. One major problem illustrated

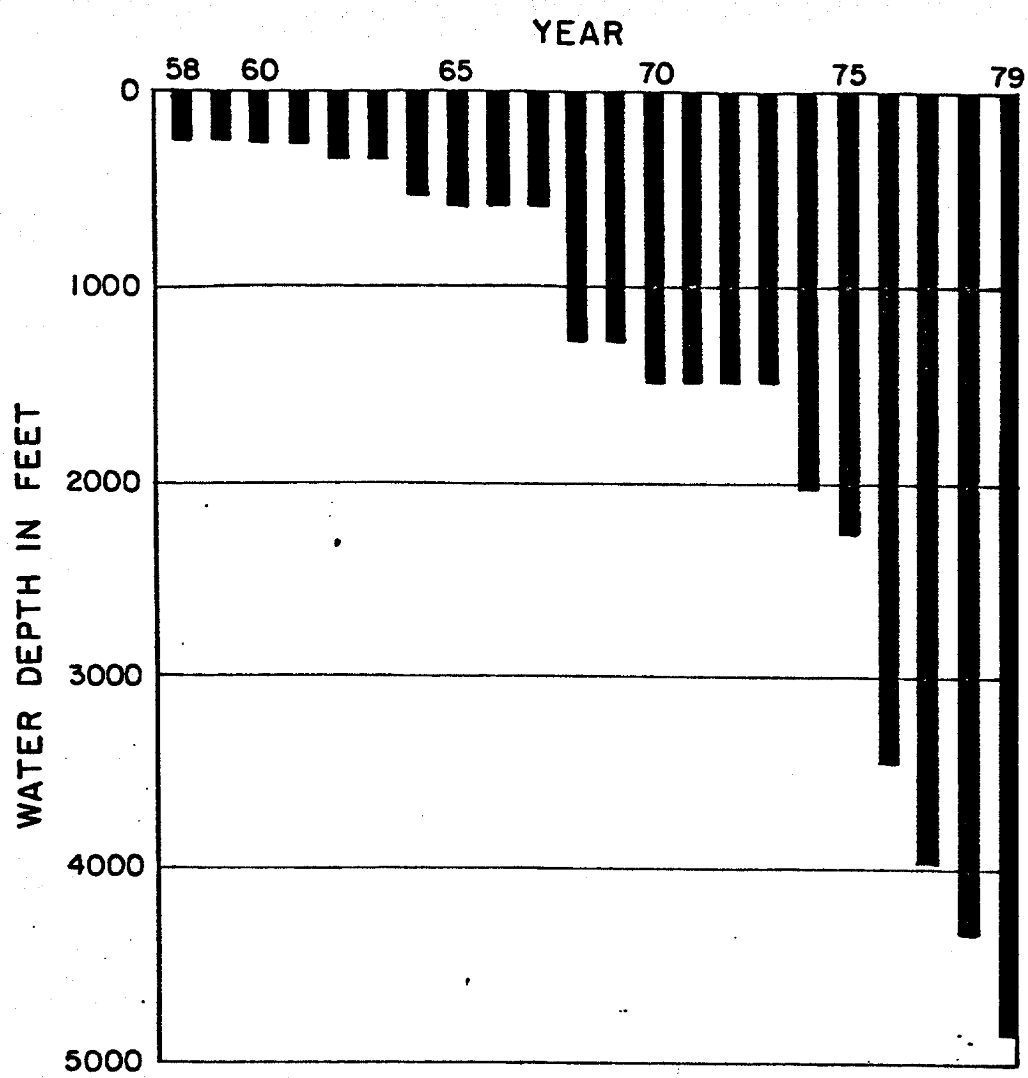

Figure 1. History of Water Depth Record for Floating Drilling Vessels (After Harris')

in Fig. 2 is the lower maximum drilling fluid density which can be used without hydrofracture. Note that the maximum mud density that can be used with a casing penetration into the sediments of 3500 ft decreases from about 13.9 lb/gal on land to 9.8 lb/gal in 13,000 ft of water. A second major problem is the rapid increase in well pressure which must be held by the adjustable choke when formation gas being circulated from the well reaches the well control equipment at the seafloor. This problem is illustrated in Fig. 3 for a hypothetical well-control example prepared using well-planning information from the NSF Ocean Margin Drilling Program[2] for an offshore New Jersey location to be drilled by the Glomar Explorer drillship in 7875 ft of water. Note the rapid change in required choke pressure calculated when the top of the gaseous fluids reaches the seafloor.

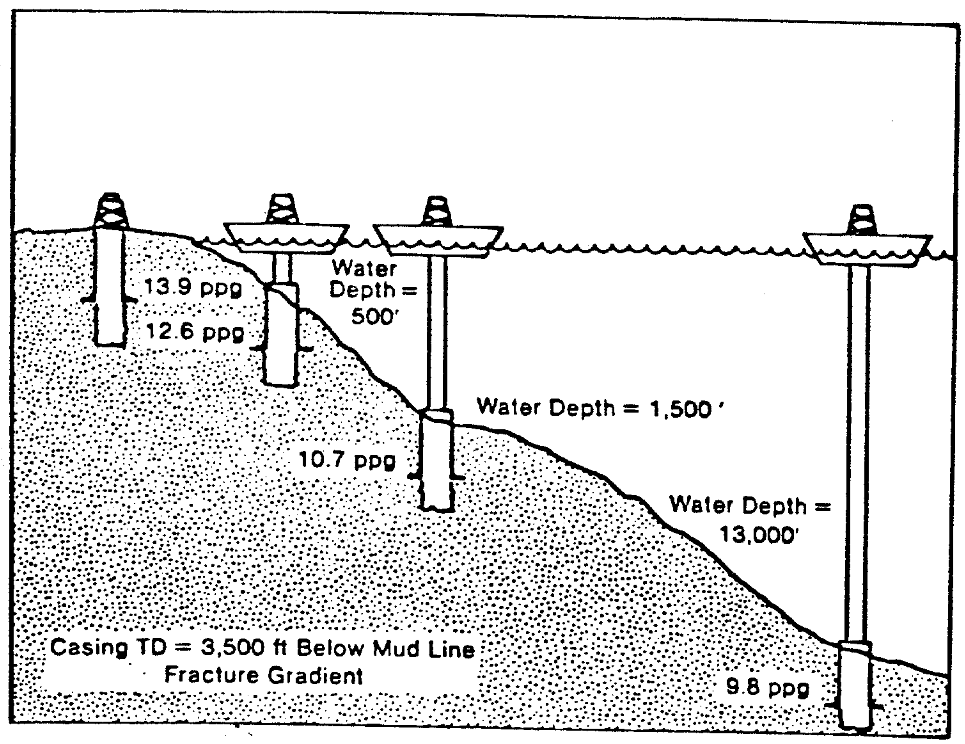

Figure 2. Effect of Water Depth on Fracture Gradient.[2]

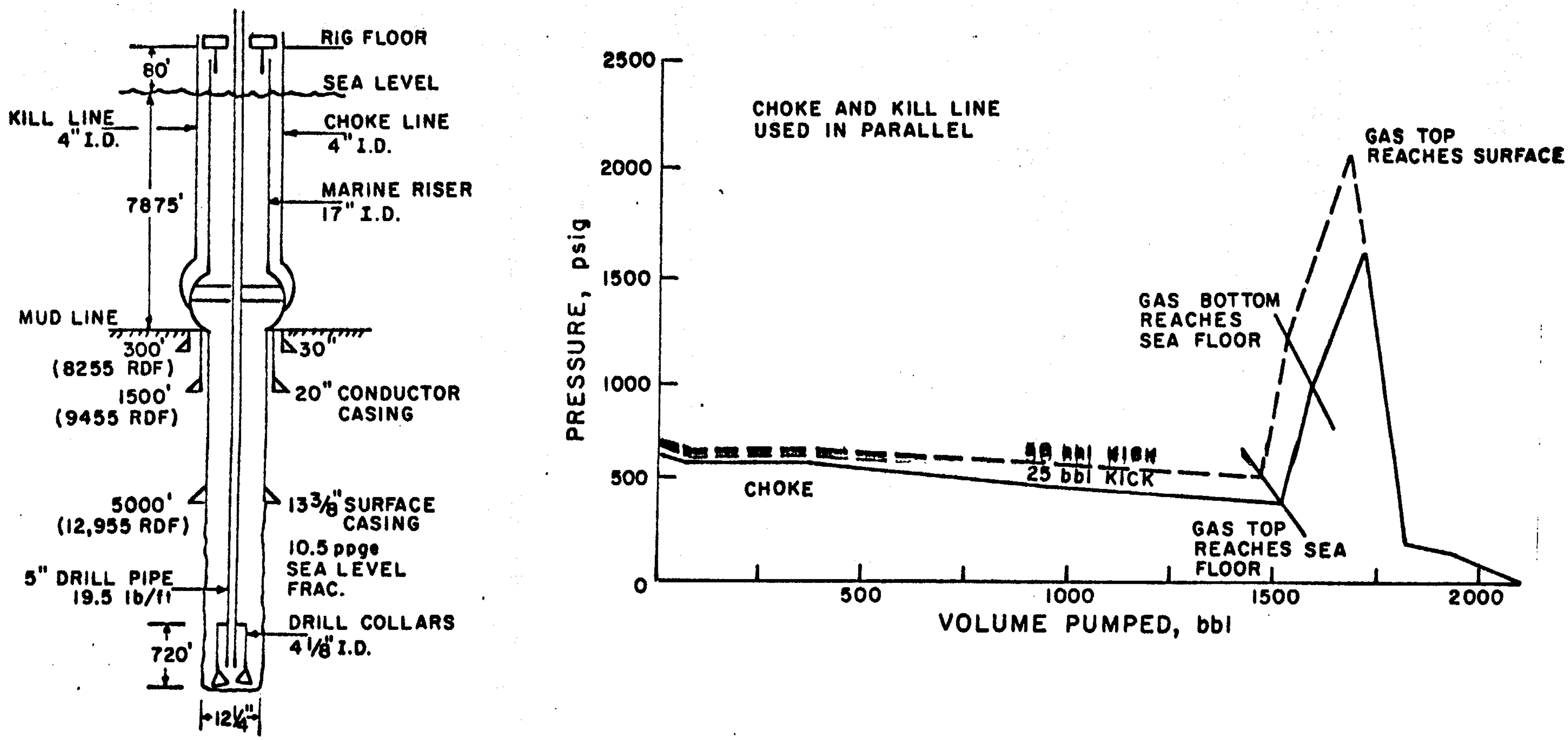

Figure 3. Example Well Control Computer Simulations for Glomar Explorer Drillship on Proposed Offshore New Jersey, Upper Rise Location.

RESEARCH OBJECTIVES

The primary objective of this research program is the development of improved blowout prevention procedures to be used in deep water floating drilling operations. The overall research plan was divided into eight tasks which will take approximately four years for completion at a total cost to the USGS of $822,962. These tasks are as follows:

1. Design of a research well facility for accurately modeling blowout control operations on a floating drilling vessel in deep water.
2. Construction of research well facility.
3. Documentation of blowout control equipment configuration and procedures currently used on deep water floating drilling vessels.
4. Experimental study of shut-in procedure for blowout control on deep water floating drilling vessels.
5. Experimental study of procedures for handling upward gas migration during the shut-in period.
6. Experimental study of pump start-up procedures.
7. Experimental study of pump out procedures with emphasis on problems occurring when a gas kick reaches the seafloor.
8. Development of a mathematical model of well behavior during the control of gas kicks on floating drilling vessels.

It should be pointed out that this research project is being jointly sponsored by industry, and the total cost of the project is approximately 2.8 million dollars. At the end of this reporting period, the third year on this project has been completed with USGS funding to date totaling $630,789.00.

A well-research facility has been designed and constructed to simulate well-control operations on a floating drilling vessel in deep water. Construction of the two-million-dollar facility was accomplished with funding from both industry and the Geological Survey. This new facility complements an older well facility constructed in 1971, which is capable of modeling well-control operations for land rigs and bottom-supported marine rigs.

A photograph of the recently completed well facility is shown in Fig. 4. The main features of this facility include: (1) a 6000-ft well, (2) a choke manifold containing four 15,000-psi adjustable drilling chokes of varying design features, (3) a Halliburton triplex pump, (4) mud tanks, (5) a mud/gas separator, (6) three mud degassers of varying design, (7) a mud-mixing system, and (8) an instrumentation and control house. The subsurface configuration of tubulars in the well were chosen so that the well would exhibit the same hydraulic behavior as a well being drilled in 3000 ft of water.

The effect of locating the BOP at the seafloor is modeled in the well using a packer and triple parallel flow tube, as described in Annual Report No. 2. Subsea choke and kill lines connecting the simulated BOP to the surface are modeled using 2.375-in. tubing. A subsea kill line valve at 3000 ft is modeled using a surface-controlled subsurface safety valve. This allows experiments to be conducted using only the choke line with the kill line isolated from the system, as is often the case in well-control operations on floating drilling vessels. A drill string is simulated using 6000 ft of 2.875-in tubing. Nitrogen gas is injected into the bottom of the well at 6000 ft to simulate a gas kick. The Nitrogen is injected into the well through 6100 ft of 1.315-

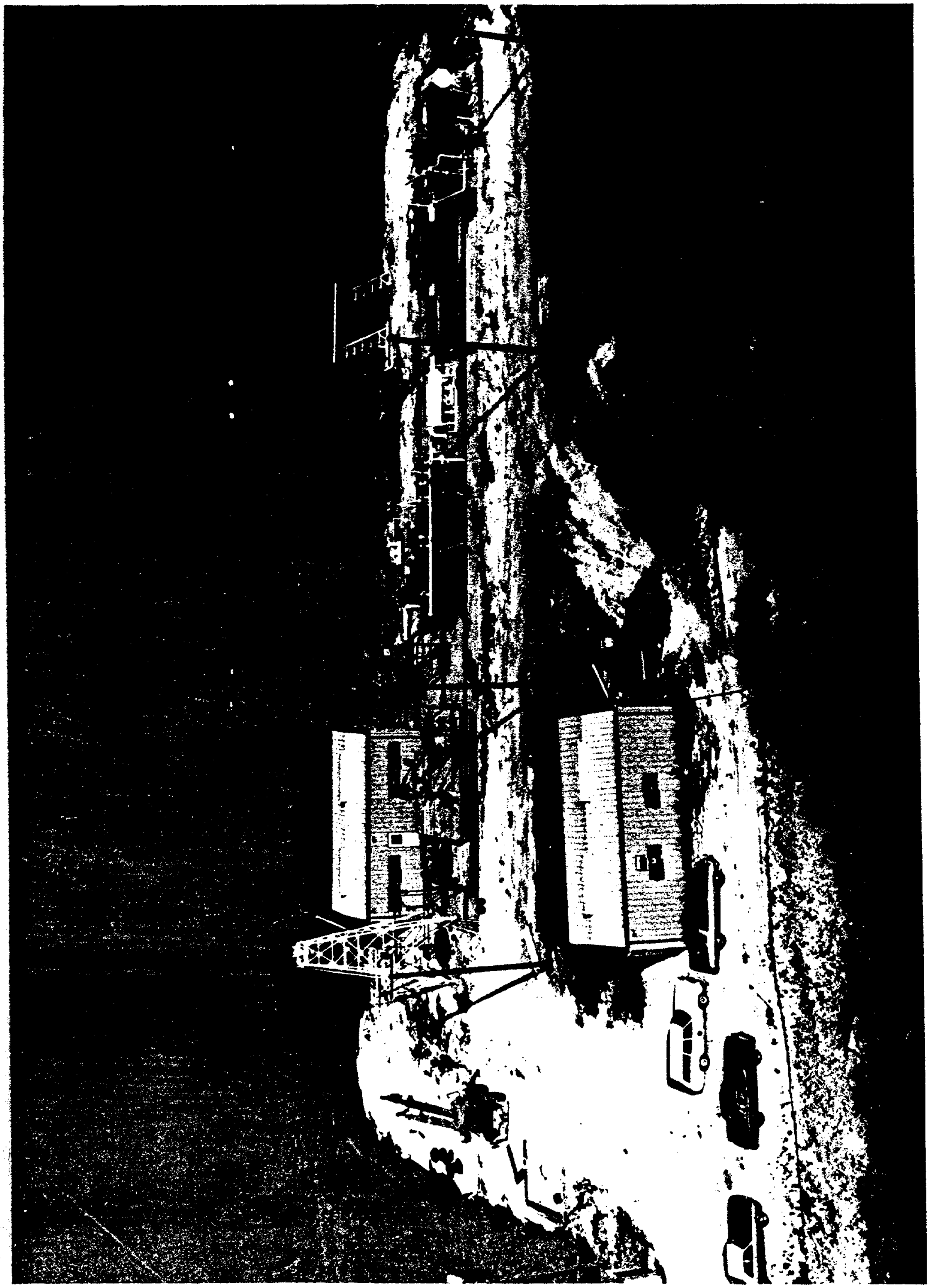

Figure 4. New Well Facility for Modeling Well Control Operations On Floating Drilling Vessels

in. tubing, which was placed inside the 2.875-in. tubing. A pressure sensor was placed at the bottom of the Nitrogen injection line to allow continuous surface monitoring of the bottomhole pressure during simulated well-control operations. The pressure signal is transmitted to the surface through 0.094-in. O.D. capillary tubing which is strapped to the 1.315-in. tubing. A check valve located at the bottom of the Nitrogen injection line allows this line to be isolated from the system after the gas kick is placed in the well.

Assembly of the new well facility was completed in July, 1981. The collection of data on actual pressure profiles obtained during simulated deepwater well-control operations began on July 4, 1981. Theoretical surface pressure profiles for two sets of high conditions are shown in Fig. 5. These pressure profiles were obtained using a "state of the art" computer simulation of the well-control process. Note the similarity between the theoretical behavior of the new well facility to the theoretical behavior of the deepwater well-control example from the NSF Ocean Margin Drilling Programs shown in Fig. 3b. Actual data taken to date using water as a drilling fluid shows some significant differences from the theoretical pressure bahavior, but the problems predicted by the theoretical calculations appear to be real.

An ultimate goal of the experimental well-control research at LSU is the development of more accurate algorithms for use in computer simulations of well-control operations. Computer simulators can provide an effective means of evaluating alternative well-control procedures, as well as providing effective well-control training exercises. An accurate computer simulation of pressure control operations requires an accurate knowledge of fluid behavior in the well. Our research has

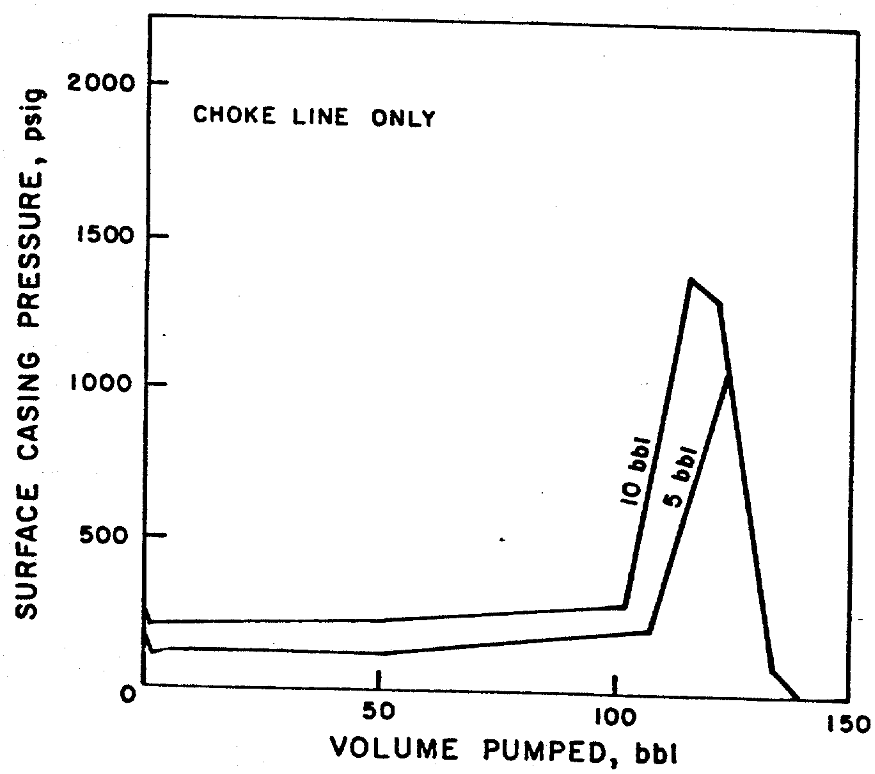

Figure 5. Theoretical Choke Pressure Profiles Computed for New Research Well.

already shown that the assumptions used at present in well-control simulations do not always reallistically model actual well behavior when gas is present. Two common assumptions found to be at fault are (1) that gas influx enters the wellbore as a continuous plug which occupies the entire annular cross section of the well and remains in this configuration during subsequent well-control operations and (2) that the gas zone does not migrate upward through the column of drilling fluid but moves instead at the same velocity as the circulating drilling fluid.

Laboratory experiments are being conducted in a three-story wellbore model (see Fig. 6) to learn more about the actual flow patterns present in well-control operations. To date, flow patterns and gas concentrations resulting for various gas feed rates have been studied in Newtonian fluids over a wide range of fluid viscosities. Shown in Fig. 7 is a photograph obtained of one flow pattern occurring in the laboratory model. These experiments indicate that bubble flow is the predominant flow pattern present as a gas kick enters a well. Very high gas feed rates are required to generate a slug flow pattern.

Experimentally-obtained average gas concentration in the kick region as a function of gas feed rate is shown in Fig. 8. Gas feed rate is expressed as a superficial gas velocity, i.e., the gas flow rate divided by the annular cross sectional area of the well. The upper limit of the experimental data of about 0.8 ft/sec corresponds to a kick rate of about 1.9 bbl/min.

In addition to the data collected on flow pattern and gas concentration in the kick zone, data on gas-bubble-rise velocity for various size bubbles and slugs were also collected. Shown in Fig. 9 is bubble-

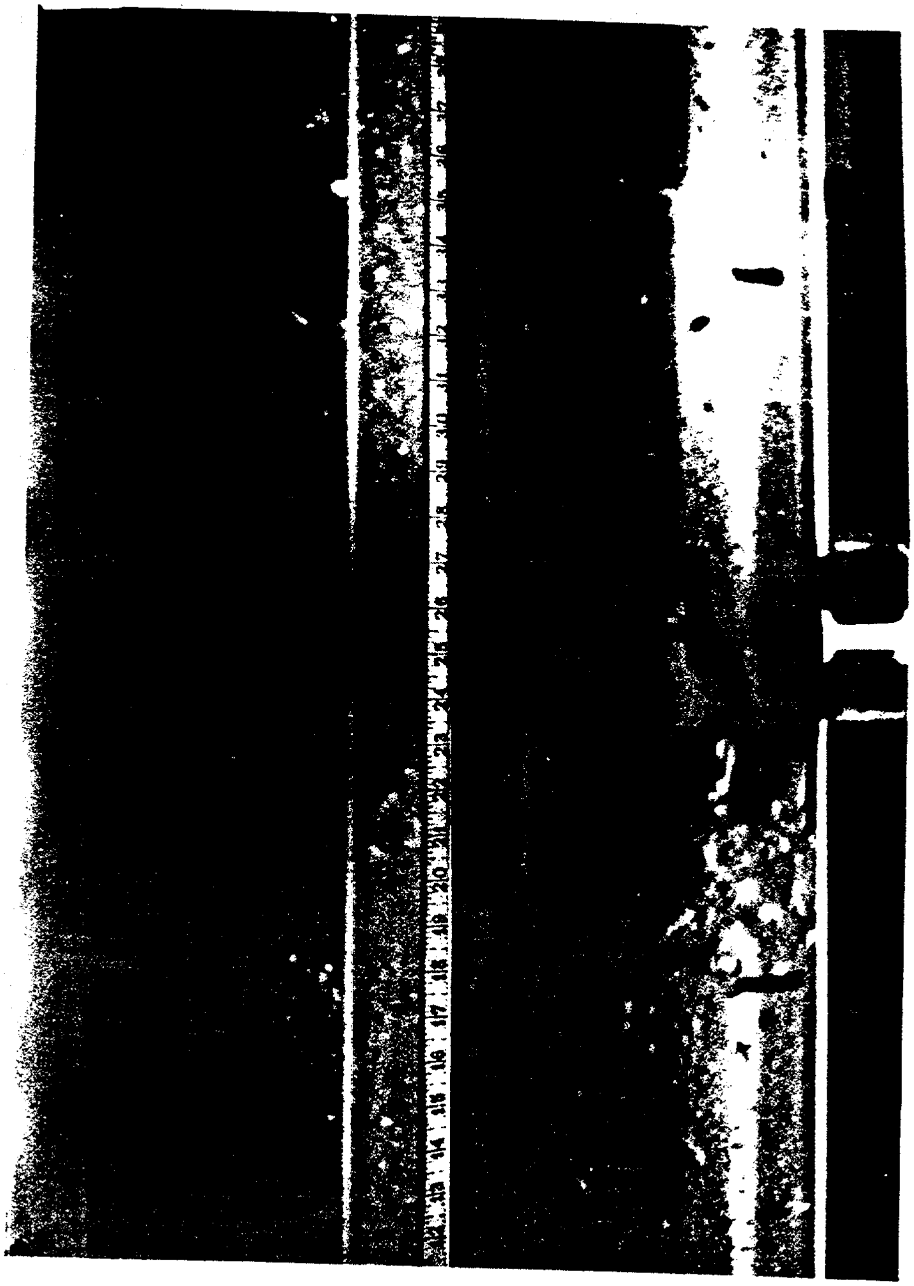

Figure 7. Example Two-phase Flow Pattern Observed in Laboratory Model.

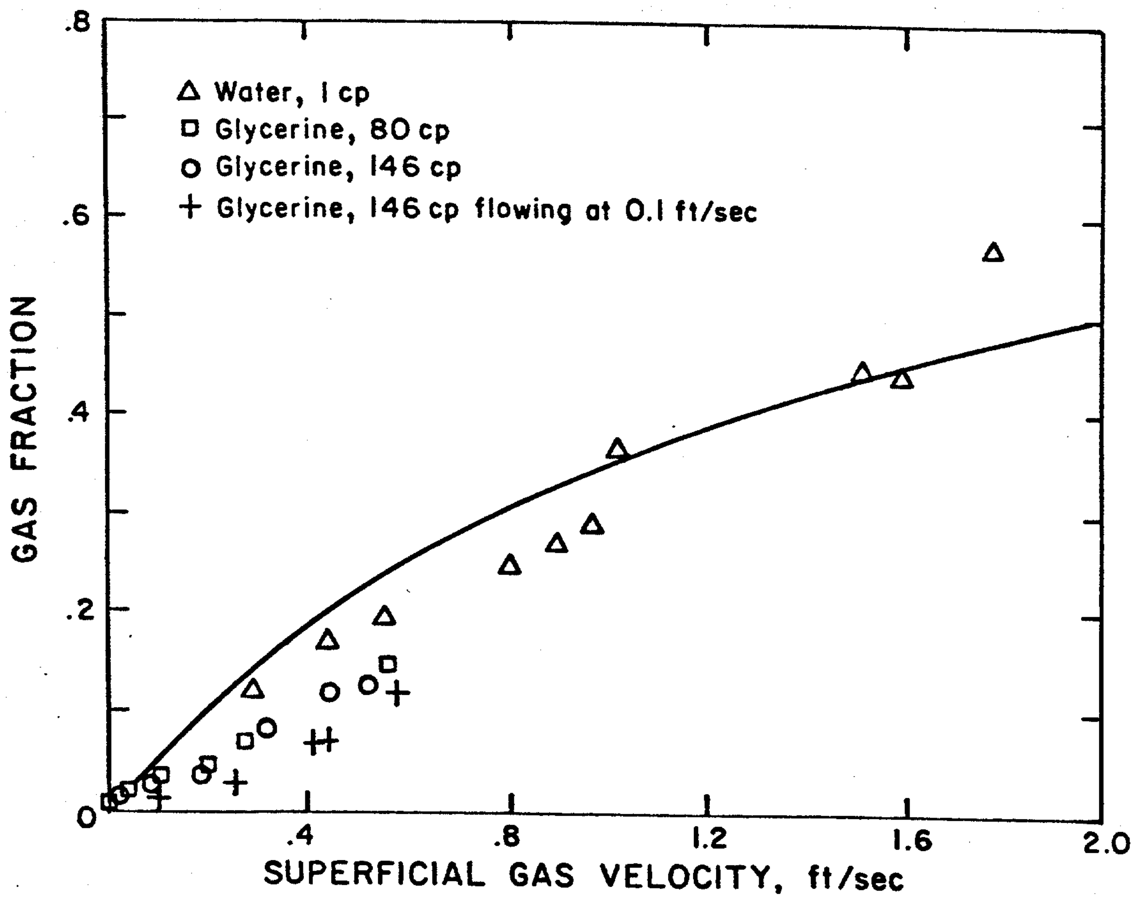

Figure 8. Gas Fraction in Kick Zone as a Function of Gas Feed Rate (Gas Feed Rate Expressed as a Superficial Gas Velocity)

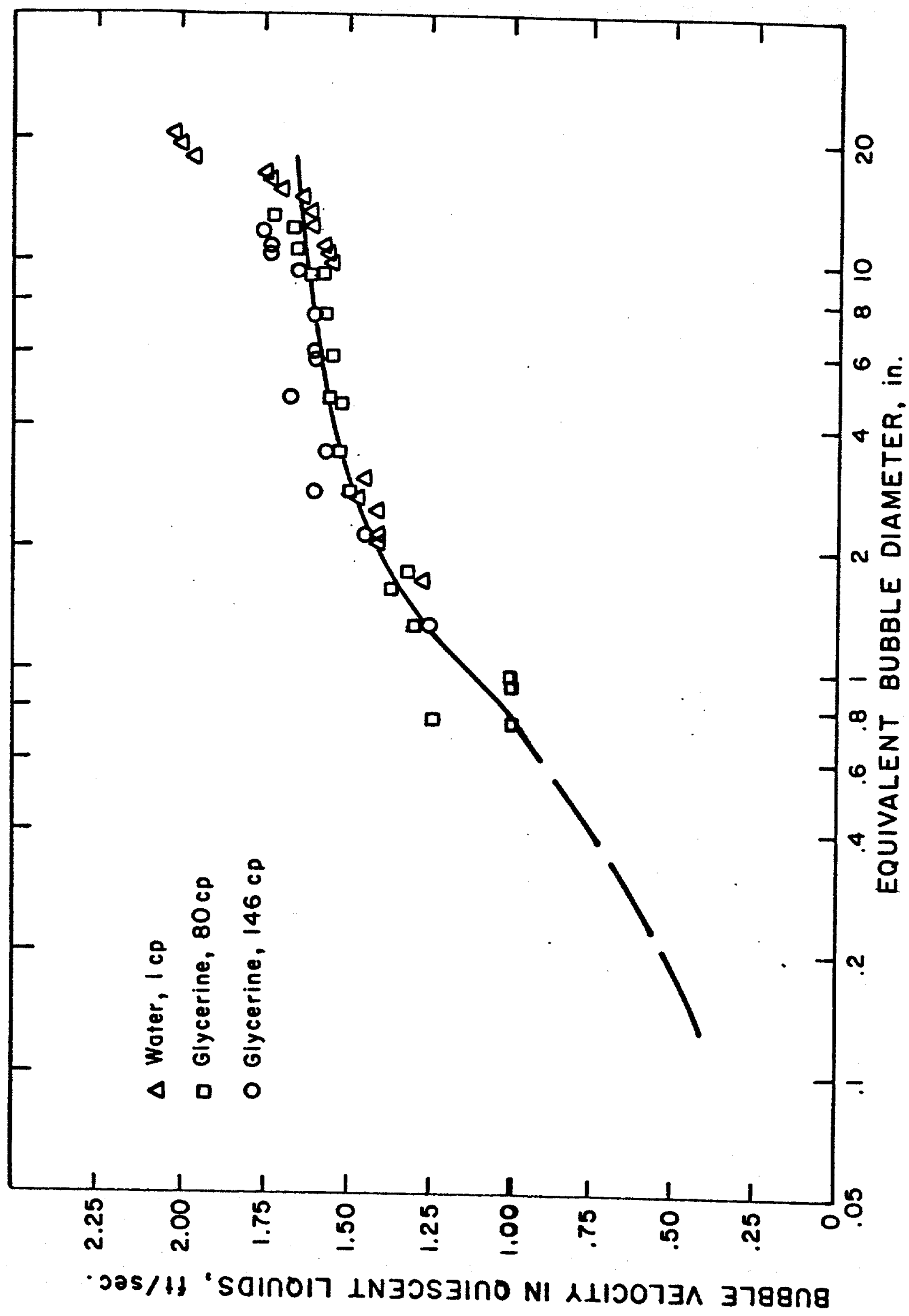

Figure 9. Measured Bubble Velocity Versus Equivalent Bubble Diameter for a Static 6.375in. by 2.375in. Annular Liquid Column.

rise-velocity relative to an observer at the surface for various bubble volumes (expressed as an equivalent spherical bubble diameter) and various liquid viscosities. Note that for the 6.375-in. by 2.375-in. annulus, the bubble-rise velocity is not greatly affected by liquid viscosity. Shown in Fig. 10 is gas-slug-slip velocity relative to the average liquid velocity above the gas slug for various slug lengths and liquid viscosities. Note that for the annular geometry studied, the gas slug slip velocity is essentially a constant, having a value of about 1.5 ft/sec.

Gas migration experiments have also been conducted in a 6000-ft well. The focus of these experiments was on an evaluation of the volumetric method of handling gas migration in a shut-in well. The volumetric method of handling gas migration has been proposed as a technique which can be applied when a meaningful drillpipe pressure is not available because of mechanical difficulties, such as a plugged drillstring, a leaking drillstring, or an off-bottom drillstring. The volumetric method, illustrated in Fig. 11, utilizes observed changes in pit level and casing pressure to maintain a nearly constant bottomhole pressure. This is accomplished by:

1. Allowing the casing pressure to rise due to upward gas migration to a value slightly above the initial shut-in pressure to allow a margin of safety. Usually about 100 psi is considered an appropriate safety margin.
2. Allowing the casing pressure to rise due to upward gas migration by an additional pressure increment. Usually about 50 psi is considered appropriate.

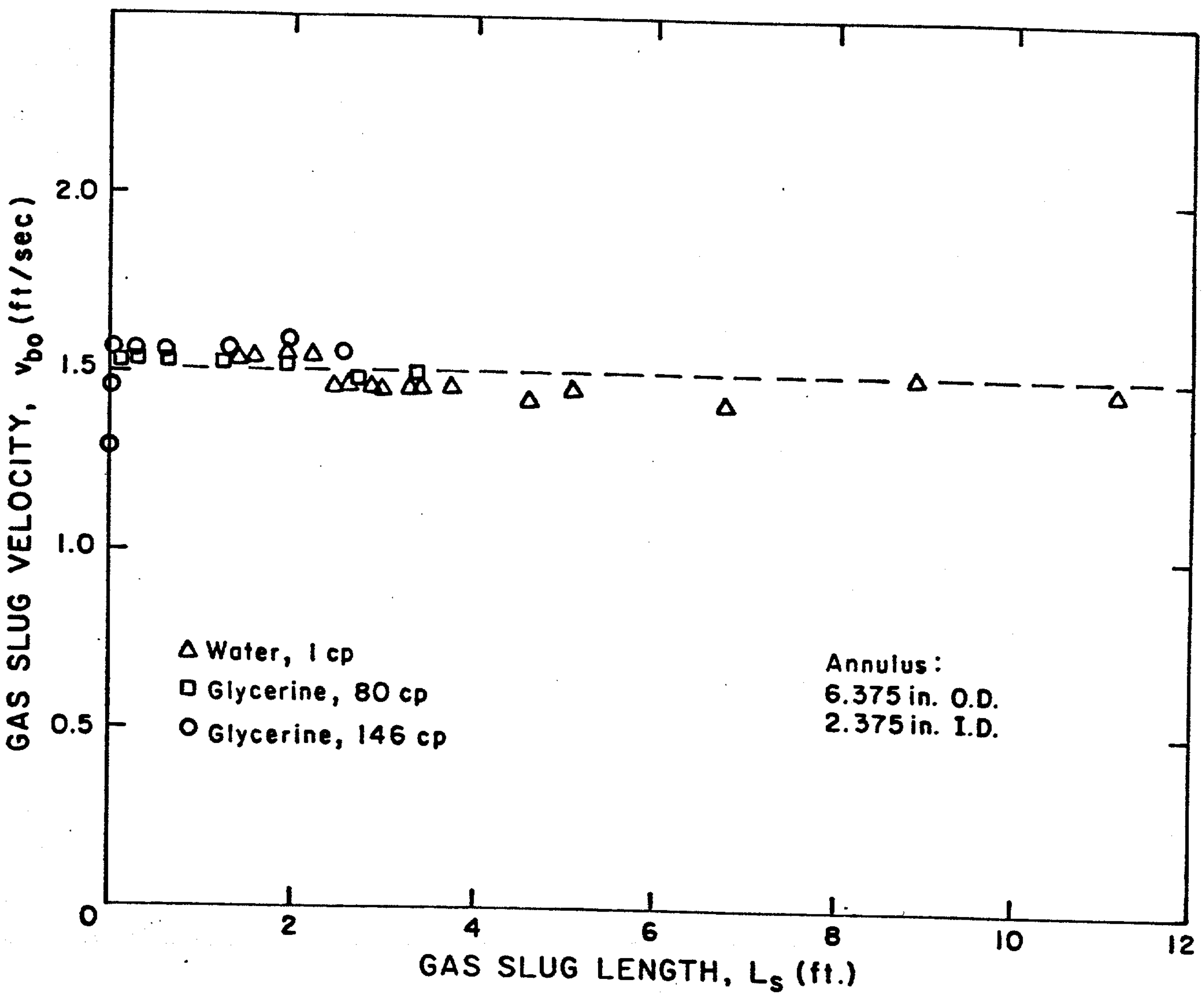

Figure 10. Slip Velocity of Gas Slugs Relative to Average Liquid Velocity Above the Gaseous Region.

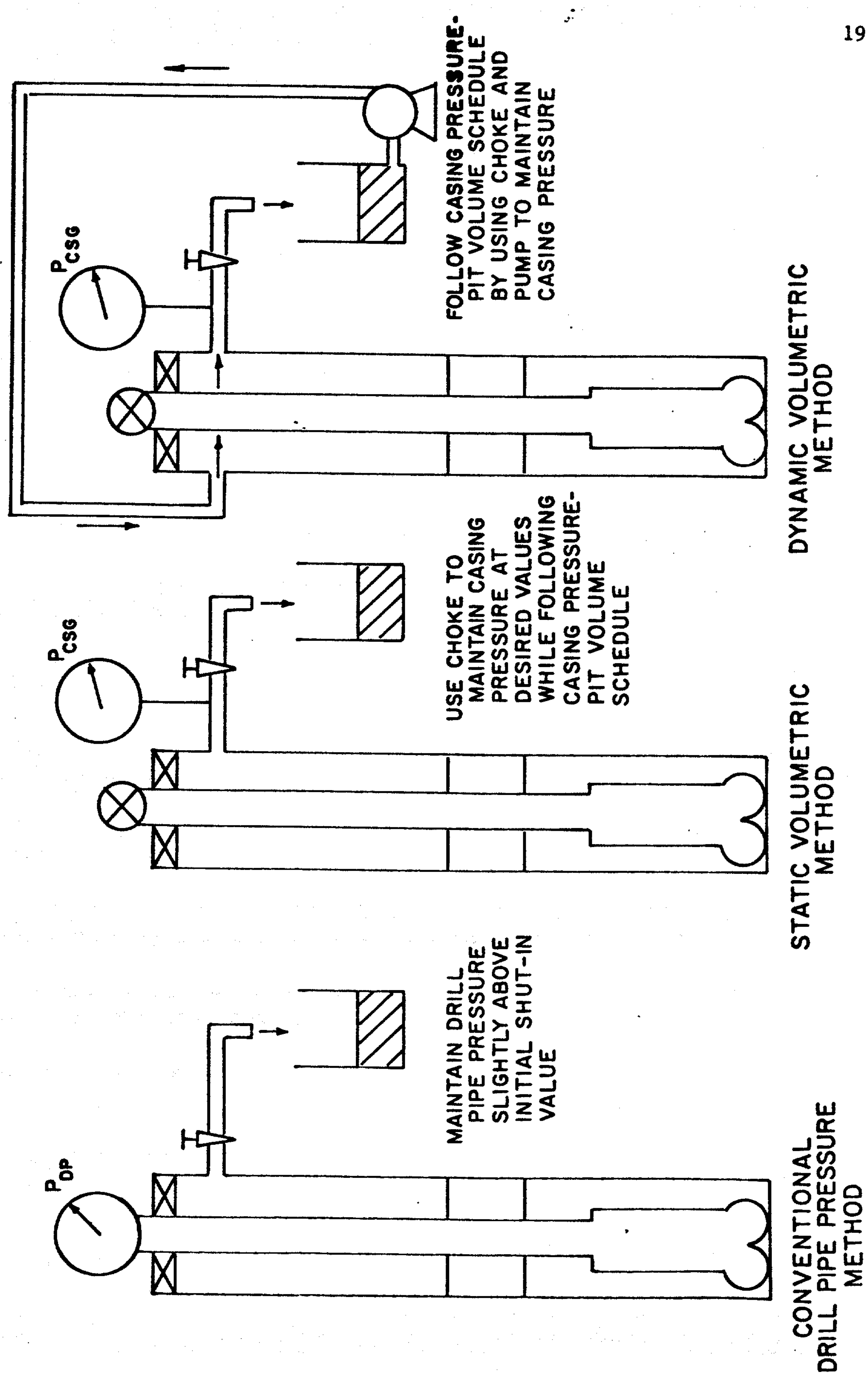

Figure 11. Proposed Methods for Safe Handling of Upward Migration of Gas Kicks in a Shut-in Well.

3. Bleeding a volume of well fluid through the adjustable drilling choke which would generate in the well a hydrostatic pressure equal to the selected pressure increment. Adjusting the choke to accomplish this release of well fluid at a near-constant casing pressure.

4. Repeating steps 2 and 3 as necessary until gas reaches the surface.

A schematic showing the experimental flow loop used to evaluate the volumetric method of handling gas migration is shown in Fig. 12. Typical results obtained using this experimental flow loop are shown in Fig. 13. Contrary to expectations and conventional calculations, surface pressure build-up did not stop after gas reached the surface. A considerable amount of gas was still rising through the drilling fluid after the leading edge of the gaseous zone reached the surface. However, once the leading edge of the gaseous zone reached the surface, subsequent bleeding operations using the adjustable choke produced only gas. Again, contrary to conventional calculations, it was possible to bleed a considerable volume of gas without loss of bottomhole pressure. As a result of the experimental work performed, the volumetric method of handling upward gas migration was found to be a viable technique for the simple well geometries studied. Additional data will be taken for the more complex geometry present for a floating drilling vessel using the new well facility.

The development of improved algorithms for computer simulations of well-control operations requires an understanding of well-control equipment response, as well as an understanding of the two-phase annular flow behavior in the well. Experimental work at LSU is also underway to

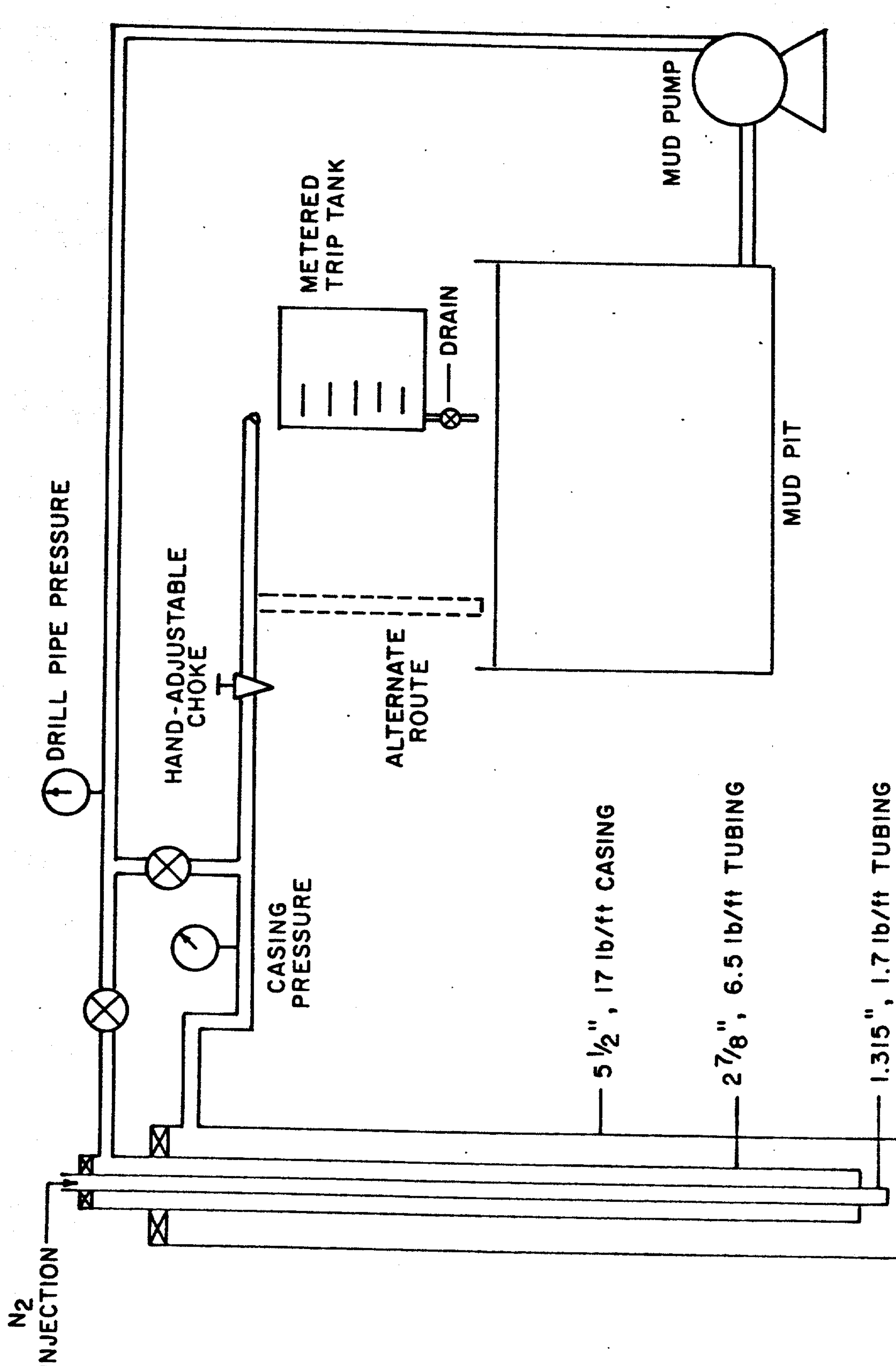

Figure 12. Experimental Flow Loop for Evaluation of Proposed Methods of Handling Upward Gas Migration.

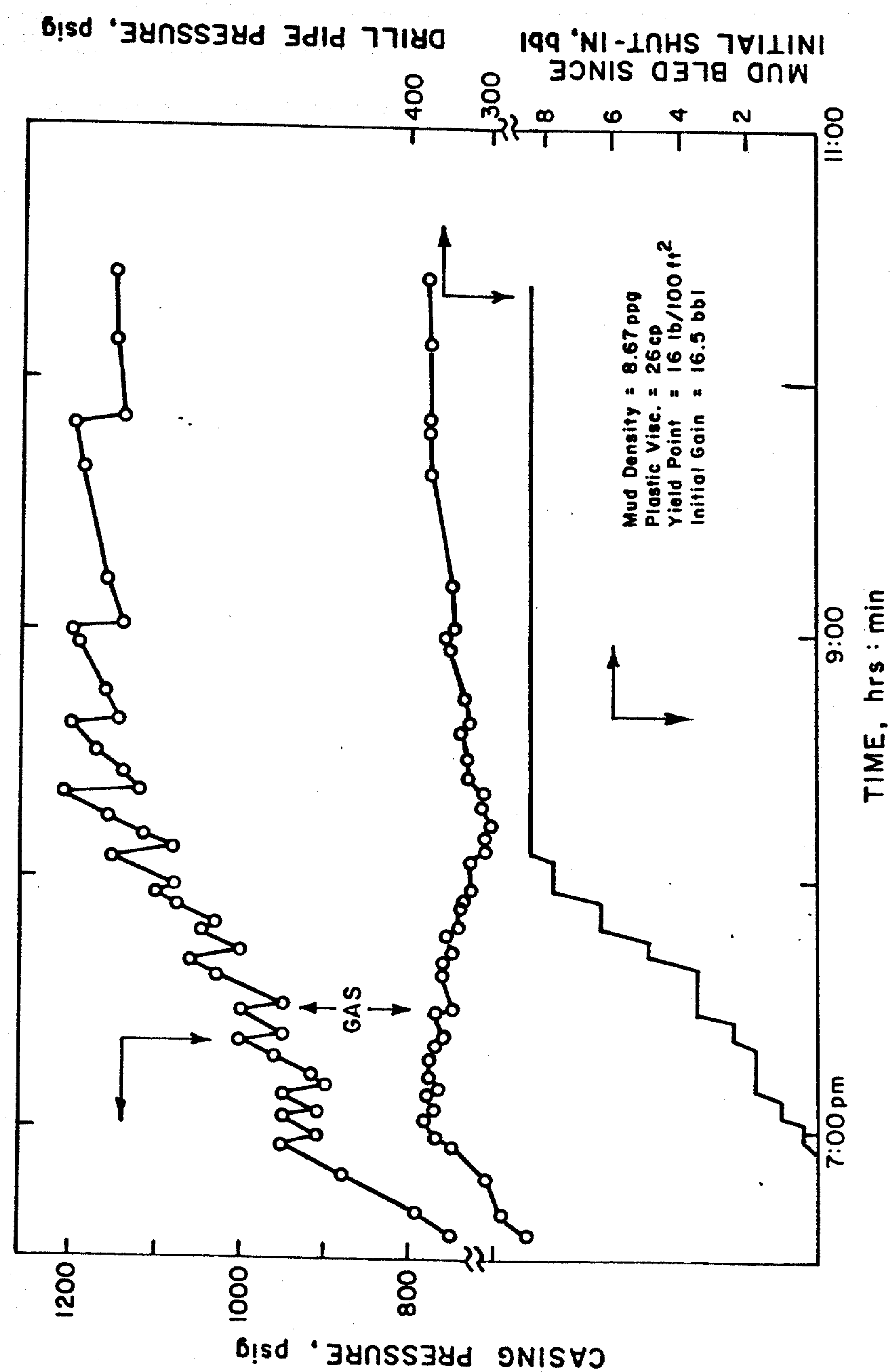

Figure 13. Example Pressure-Volume-Time Data For Static Volumetric Method (Run 12).

determine the flow characteristics of the commercially available drilling chokes. It is hoped that the flow coefficient data collected will lead to greatly improved algorithms for computing the changes in well pressures and flow rates with time caused by incremental changes in choke position by the choke operator. Similarly, it is hoped that flow coefficient data collected on an annular blowout preventer for various stages of closure will lead to more accurate algorithms for predicting initial pressure surges during well closure and ultimately to improved shut-in procedures. Typical flow coefficient data obtained on one of the commercially available drilling chokes is given in Table 1, and typical flow coefficient data obtained on an annular BOP is given in Table 2.

One aspect of the research program being conducted at LSU is the evaluation of alternative well-control procedures. In order to keep abreast of current practice, a study documenting the existing equipment and procedures now in use is being conducted. In this study, equipment currently being manufactured was first cataloged. A survey of deepwater rigs was then conducted to identify how the available equipment was being configured in actual practice. A number of drillships and semi-submersible rigs were visited in conjunction with this study. Next, all USGS-approved subsea well-control manuals were surveyed in order to catalog the various recommended procedures for use of the existing equipment. Some limitations of existing equipment and procedures will be explored experimentally using the new research well facility.

Table 1 - Example Flow Data for Swaco Remote Adjustable Drilling Choke (8.6 ppg mud with plastic viscosity of 20 cp and yield point of 10 $lb/100\ ft^2$)

Choke Position (fraction open)	Flow Rate (gpm)	Upstream Pressure (psig)	Valve Capacity Coefficient Cv
0.750	280	20	63.62
	285	23	60.38
	300	42	47.04
	312	62	40.26
	320	70	38.86
	323	80	36.69
0.625	277	27	54.17
	295	55	40.42
	308	70	37.40
	320	80	36.35
	328	100	33.33
0.500	275	40	44.18
	295	80	33.52
	305	105	30.24
	315	120	29.22
	320	135	27.98
0.333	265	40	42.57
	270	50	38.80
	273	70	33.15
	275	100	27.94
	277	130	24.69
0.250	267	90	28.60
	271	170	21.12
	273	270	16.88
	275	370	14.53
	277	540	12.11
0.200	265	360	14.19
	270	870	9.30
	273	1200	8.01
0.167	251	830	8.85
	255	1120	7.74
	260	1500	6.82

Table 2 - Example Flow Characteristics Data for 6-in.
Annular Blowout Preventer Using Water

Drill Pipe O.D. (in.)	Piston Position (in.)	Piston Position Frac. (open)	Flow Rate (gpm)	Well Pressure (psig)	Value Coefficient Cv
2.375	0	1.000	162.6	0	-
	1.552	0.483	168.0	20	37.6
	1.968	0.613	168.0	30	30.7
	2.3715	0.7386	168.0	30	30.7
	2.7854	0.8675	130.9	580	5.4
	2.8840	0.8982	84.0	1400	2.2
	3.211	0.0	0.0	-	0
	2.6507	0.8124	177.0	60	22.9
			119.0	20	26.6
			48.0	3	27.7
			180.0	40	28.46
			113.5	20	25.4
			48.5	3	28.0
	2.8546	0.8748	157.5	320	8.8
			107.5	190	7.8
			46.0	40	7.3
			150.5	420	7.3
			120.0	320	6.7
			47.5	140	4.0
	3.0585	0.9373	101	1280	2.8
			54.5	820	1.9
			20.5	560	0.87

- Automatic Closure -

REFERENCES

1. Harris, L. M.: "Design for Reliability in Deepwater Floating Drilling Operations." The Petroleum Publishing Co., Tulsa, Oklahoma, 1979.

2. "Ocean Margin Drilling Program" Volume III - Final Report, National Science Foundation, December, 1980.