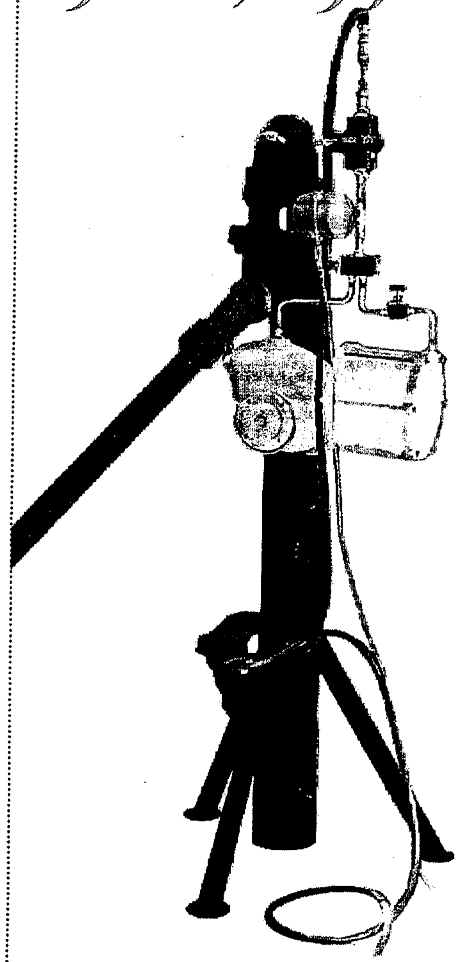
WELL CONTROL WORKSHOP

LSU/MMS

november 19–20, 1996



PETROLEUM ENGINEERING
RESEARCH AND TECHNOLOGY
TRANSFER LABORATORY

BATON ROUGE, LOUISIANA

Registration	8:00 A.M	**ABELL BOARD OF DIRECTORS ROOM** Lod Cook Alumni Center 3838 West Lakeshore Drive, Baton Rouge, LA

TUESDAY MORNING - SESSION 1, *ABELL BOARD OF DIRECTORS ROOM*

Regional Operations Technical Assessment Committee	8:30 A.M.	1. **INTRODUCTION AND WELCOME** Adam T. Bourgoyne, Jr., *LSU*
	8:40 A.M.	2. **OBJECTIVES AND SCOPE OF MEETING** James Regg, *MMS*
Sustained Casing Pressure on Producing Well	8:50 A.M.	3. **SUSTAINED CASING PRESSURE: REVIEW OF PROBLEM** Lee Fowler, *MMS*
	9:20 A.M.	4. **CURRENT REGULATORY REQUIREMENTS AND OPERATIONAL GUIDELINES** James Regg, *MMS*
	9:50 A.M.	5. **CURRENT METHODS FOR ANALYSIS AND REMEDIATION** Stuart Scott, *LSU* and Adam T. Bourgoyne, Jr., *LSU*
	10:20 A.M.	**Coffee Break** Courtesy of Diamond Offshore Drilling, Inc.
	10:40 A.M.	6. **MECHANISMS FOR LONG-TERM GAS MIGRATION BEHIND CASING** Ronald R. Faul, *Halliburton Energy*
	11:10 A.M.	7. **APPLICATIONS OF BLAST FURNACE SLAGS IN PREVENTING FLUID MIGRATION BEHIND CASING** Fred Sabins and Timothy Edwards, *Westport Technology*
	11:40 A.M.	**Lunch** (Courtesy of Wild Well Control, Inc.) *Willis Noland and John Laborde Hall*

TUESDAY AFTERNOON - SESSION 2, *ABELL BOARD OF DIRECTORS ROOM*

	1:00 P.M..	8.1 **CEMENT SLURRY VIBRATION - PART I** John P. Haberman, *Texaco E & P*
	1:30 P.M.	8.2 **CASE HISTORY OF WELL WITH SUSTAINED CASING PRESSURE: VOLUMETRIC KILL USING ZINC BROMIDE** Ralph Hamrick, *SECO* and Craig Landry, *CNG Producing, Inc.*
	2:00 P.M.	9. **CASE HISTORY: ABANDONING A WELL WITH SUSTAINED CASING PRESSURE** David Barnett and Pat Campbell, *Wild Well Control, Inc.*
	2:30 P.M.	Coffee Break
	2:50 P.M.	10. **INDUSTRY INPUT AND OPERATIONAL CONSIDERATIONS** A. Invitation for Industry Comments or Presentations B. Recommendations
	3:15 P.M.	11. **FOLLOW-UP DISCUSSION**
	3:45 P.M.	12. **PROGRESS REPORT ON STUDY OF BOP TEST FREQUENCY** Bill Hauser, *MMS*
Well Control Update		13. **STATUS REPORT—SUPPORT "O" TRAINING REGULATIONS (cancelled)** Joe Levine, *MMS*
	4:00 P.M.	14. **SUMMARY AND CONCLUSIONS** James Regg, *MMS*
Tour of Research Well Facility	6:00 P.M.	**BARBECUE** (Courtesy of SWACO Geolograph) and SITE VISIT 2829 Gourrier Road, *Blowout Prevention and Research Well Facility*

WEDNESDAY MORNING - SESSION 3, *ABELL BOARD OF DIRECTORS ROOM*

Well Control Research Program Review

8:00 A.M.	15.	**OVERVIEW OF LSU RESEARCH PROGRAM ON WELL CONTROL** Adam T. Bourgoyne, Jr., *LSU*
8:30 A.M.	16.	**IMPROVEMENTS IN LSU/MMS RESEARCH AND TRAINING WELL FACILITY** Richard Duncan, *LSU*
8:50 A.M.		**WORKSHOP DISCUSSION**
9:00 A.M.	17.	**PREVENTION OF FLOW AFTER CEMENTING OF SURFACE CASING** Wojciech Manowski, *LSU*
9:30 A.M.		**WORKSHOP DISCUSSION**
9:40 A.M.		**Coffee Break**
10:00 A.M.	18.	**FEASIBILITY STUDY OF DUAL DENSITY SYSTEM FOR DEEPWATER DRILLING** Clovis Lopes, *LSU*
10:30 A.M.		**WORKSHOP DISCUSSION**
10:40 A.M.	19.	**FINITE ELEMENT ANALYSIS OF SOFT SEDIMENT BEHAVIOR DURING LEAK-OFF TESTS** Andrew Wojtanowicz, *LSU*
11:10 A.M.		**WORKSHOP DISCUSSION**
11:20 A.M.	20.	**DENSITY, STRENGTH, AND FRACTURE GRADIENTS FOR SHALLOW MARINE SEDIMENTS** Chris Sandoz and Clay Kimbrell, *LSU*
11:45 A.M.		**WORKSHOP DISCUSSION**
11:55 A.M.		**Lunch** (Courtesy of Halliburton Energy Services) *Willis Noland and John Laborde Hall* Robert LaBelle, Chief, Technology Assessment and Research Branch, *MMS*

WEDNESDAY AFTERNOON - SESSION 4, *ABELL BOARD OF DIRECTORS ROOM*

1:00 P.M.	21.	**DRILL STRING SAFETY VALVE TEST PROGRAM** Adam T. Bourgoyne, Jr., *LSU*; Angelique Lawless, *Amoco;* Elliot D. Coleman, *LSU* and Thomas T. Core Jr., *LSU*
1:20 P.M.	22.	**PROGRESS REPORT ON NEW LOW TORQUE DRILL STRING SAFETY-VALVE DESIGN** L. S. Stephens, *LSU;* Elliot D. Coleman, *LSU* and Thomas T. Core Jr., *LSU*
1:40 P.M.		**WORKSHOP DISCUSSION**
1:50 P.M.		**Coffee Break**
2:10 P.M.	23.	**POST ANALYSIS OF RECENT BLOWOUTS AND NEAR MISSES** John Smith, *LSU*
2:30 P.M.	24.	**AUTOMATED DETECTION OF UNDERGROUND BLOWOUTS** Allen Kelly, *Diamond Offshore Drilling, Inc.* *(Previously LSU)* and Ben Bienvenu, *LSU*
3:00 P.M.		**WORKSHOP DISCUSSION**
3:10 P.M.	25.	**CEMENT SLURRY VIBRATION - PART II** Andrew Wojtanowicz, *LSU*
3:40 P.M.	26.	**OPEN FORUM FOR INDUSTRY AND MMS INPUT** Adam T. Bourgoyne, Jr., *LSU* and Charles Smith, *MMS*
4:00 P.M.	27.	**SUMMARY AND CONCLUSIONS** Adam T. Bourgoyne, Jr., *LSU* and Charles Smith, *MMS*

Project 8

HISTORY OF LSU/MMS RESEARCH PROGRAM

by Adam T. Bourgoyne, Jr., LSU

LSU, with the support of the petroleum industry and the US Minerals Management Service, has maintained an on-going research program in blowout prevention for more than a decade. The initial emphasis was on deep-water well control procedures. In January, 1981, a research well facility was completed to provide a near full scale system for experimentally studying well control procedures that could be applied in a deep water environment. The facility was centered around a 6,000 ft well complete with subsurface equipment which allowed essentially full scale modeling of the flow geometry present on a floating vessel operating in 3,000 ft (1000 m) of water. Extensive new surface equipment also was installed to allow highly instrumented well-control experiments and training exercises to be conducted.

Funding for the new research and training well facility was obtained through the combined support of a consortium of 53 companies in the petroleum and construction industries. The project was given a big boost when Goldking Production Company, after drilling a 10,000-ft, $670,000 dry hole on the LSU campus agreed to donate the well to LSU. Thirteen major oil companies contributed special grants totaling $200,000 for the needed well completion work and surface facilities. Grants of equipment and services valued at $1,200,000 were provided by 40 service companies. In addition, approximately $200,000 of the well completion and site preparation costs were provided as part of a research contract sponsored by the Minerals Management Service.

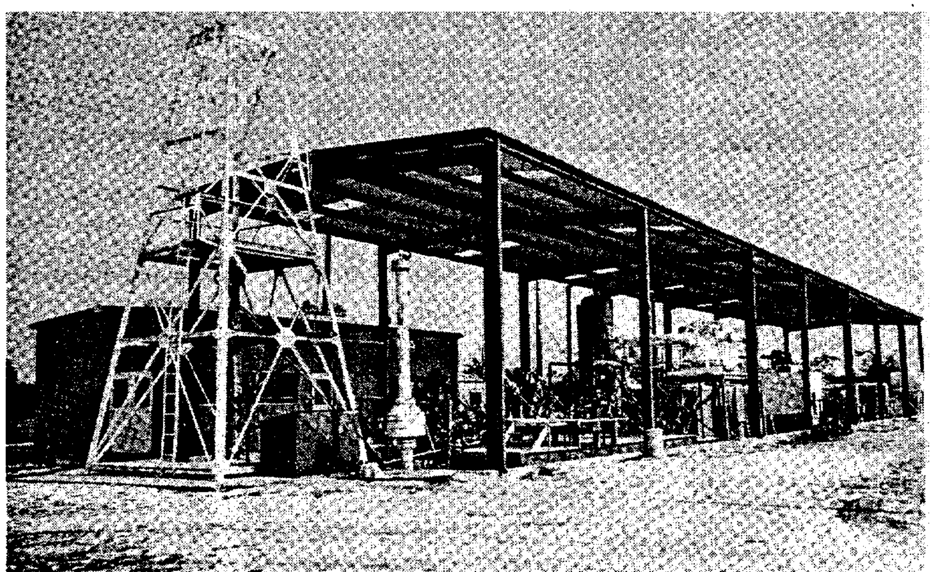


Figure 1 - Photograph of research well facility when it became operational in 1981.

A 1981 photograph of the research facility is shown in Figure 1. The main features of the facility included:

- A 6,000 ft well,
- A choke manifold containing four 15,000-psi adjustable drilling chokes,
- A 250-hp triplex pump,
- Two mud tanks with a combined capacity of 550 bbl,
- A high capacity mud-gas separator,

- Three degassers of varying designs,
- A mud mixing system,
- An instrumentation and control house shown in Figure 2, and
- A classroom building.

The subsurface configuration of tubulars in the well was chosen so the well would exhibit the same hydraulic behavior during pressure control operations as a well being drilled from a floating drilling vessel in 3000 ft of water.

The blowout prevention problem on a floating drilling vessel in deep water is complicated by the location of the blowout preventer (BOP) stack at the seafloor rather than at the surface and the use of multiple high pressure subsea flowlines from the BOP to the surface. In shallow water, the effect of the subsea flowlines is small and the well control system responds much like well control equipment on a land rig or a bottom supported marine rig. However, in very deep-water wells further offshore, the consequences of this special flow geometry become much more pronounced.

The effect of locating the BOP at the seafloor was modeled in the research well using a Baker packer and a Baker triple parallel

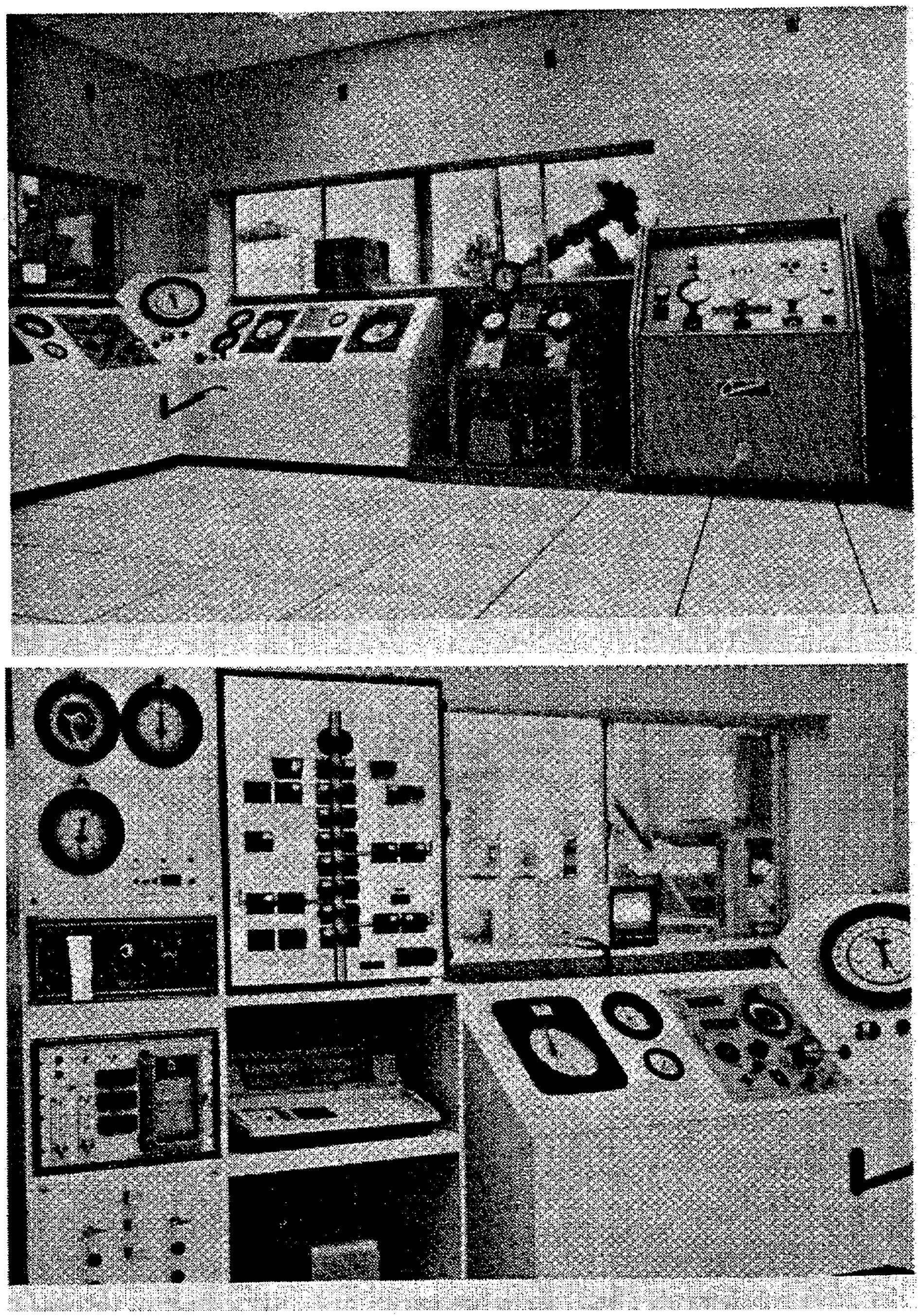


Figure 2 - Instrumentation and control panel.

flow tube as shown in Figure 3. Subsea flowlines connecting the simulated BOP to the surface were modeled using 2.375-in. tubing. A subsea wing valve on one flowline is modeled using a Hydril surface-controlled subsurface safety valve. The simulated wing valve allowed experiments and training exercises to be conducted using only one flow line, with the other line isolated from the system, as is often the case on floating drilling vessels.

Drill pipe was simulated using 6,000 ft of 2.875-in. tubing. Nitrogen gas was injected into the bottom of the well at 6000 ft to simulate influx from a high pressure gas formation. The nitrogen was injected into the well through 6,100 ft of 1.315-in. tubing, which was placed inside the 2.875-in. tubing.

A Sperry Sun pressure transmission system was placed at the bottom of the nitrogen injection line to allow continuous surface monitoring of the bottom-hole pressure during simulated well control operations. The pressure signal was transmitted through 0.125-in. capillary tubing which was strapped to the 1.315-in. gas injection tubing. A check valve located at the bottom of the gas injection line allows this line to be isolated from the system after the gas kick is placed in the well.

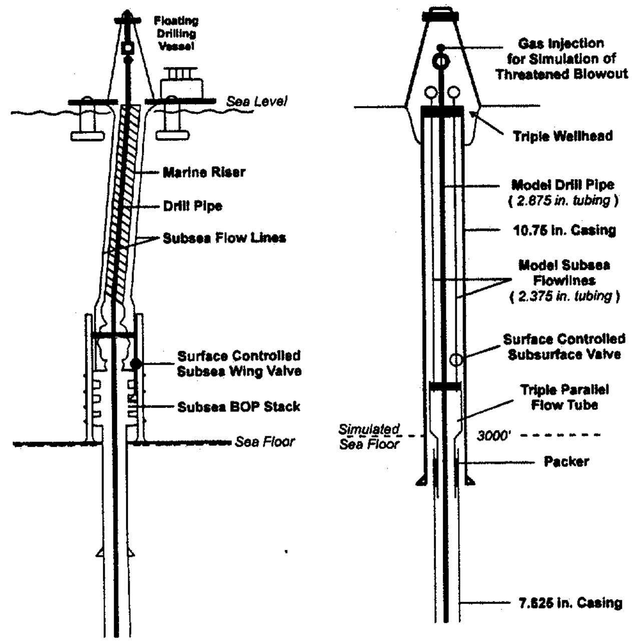


Figure 3 - Well design to model deepwater well control operations.

Like many other aspects of drilling operations, the problem of blowout prevention increases in complexity for floating drilling vessels operating in deep water. Several special well control problems stem from greatly reduced fracture gradients and the use of long subsea choke and kill lines. Figure 4 shows the approximate effect of water depth on fracture gradients below surface casing, expressed in terms of the maximum mud density that can be sustained during normal drilling operations. Note that the maximum mud density that can be used with casing penetrating 3,500 ft (1067 m) into the sediments decreases from about 13.9 lb/gal (1666 kg/m3) on land to about 9.8 lb/gal in 13,000 ft (3962 m) of water. These lower fracture gradients result primarily because the open hole must support a column of drilling fluid that extends far above the mud line to the rig floor. This additional column weight is only partially offset by the seawater. An additional contributing factor is

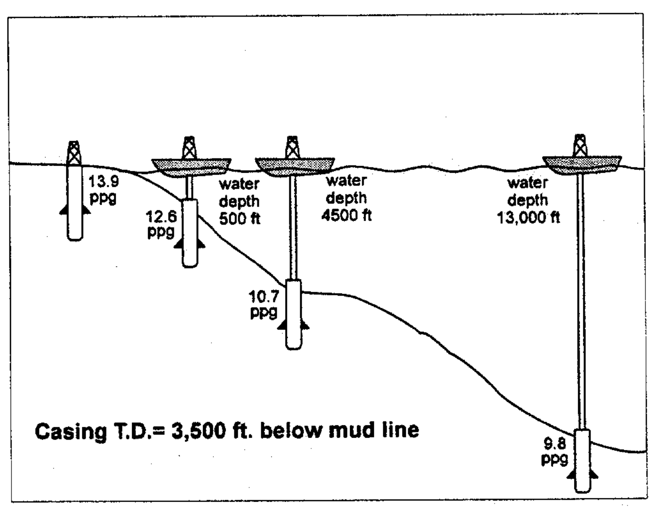


Figure 4 - Effect of water depth on fracture gradient for 3500 ft penetration.

the relatively low bulk density of unconsolidated shallow marine sediments.

Abnormal formation pressure is often encountered at more shallow depths in deep water areas of the Gulf of Mexico. The combination of abnormal formation pore pressure and low fracture resistance results in a need for a large number of casing strings to maintain even a small safety margin between the choke pressure required for well control in the event of a threatened blowout and the choke pressure that would cause formation fracture. Thus, it is often important to be able to maintain pressures close to the target pressure during well control operations. However, manual choke operation is often far from infallible, especially for the complex geometry present in deep water.

Shown in Figure 5 is an example kick simulation in the research well for a 21 bbl gas kick pumped out by industry field personnel during a training exercise. This example illustrates a problem that can occur when the frictional pressure loss in the chokeline is almost as large as the shut-in casing pressure. On completion of pump startup, the required backpressure on the annulus is provided almost entirely by the frictional loss in the choke line. Thus, the choke can be opened far beyond the normal operating range with only a small response in drillpipe pressure. If the choke operator is caught with the choke in nearly a full open position when gas enters the subsea choke line, it is extremely difficult to close the choke quickly enough without closing it too much. Note that in this example, a +400-psi (2758-kPa) error in bottom hole pressure occurred while gas was in the subsea choke line.

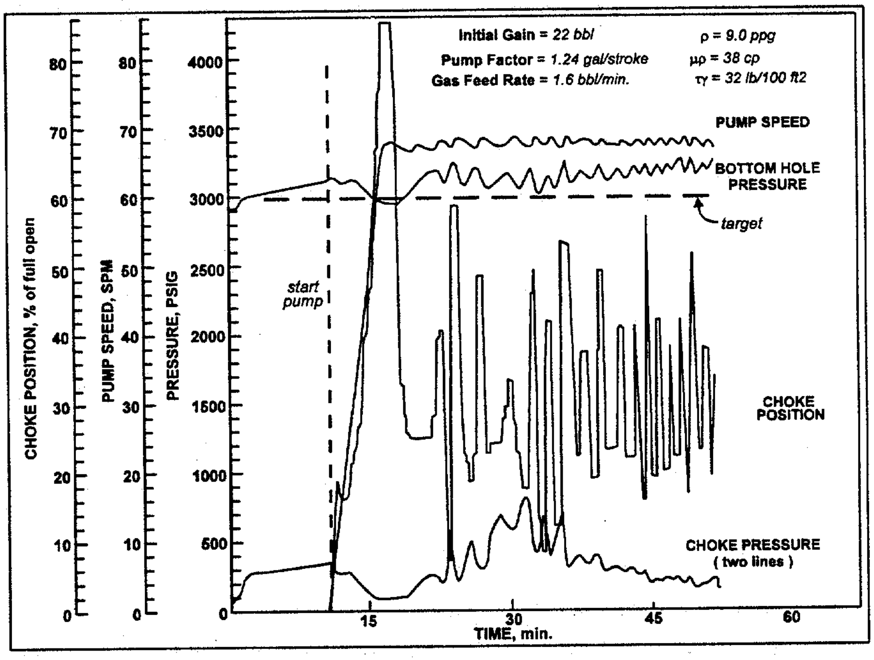


Figure 5 - Example data collected for well control operations in deep water.

A number of common situations were experimentally studied that can lead to errors on the part of the choke operator as large as the example shown in Figure 5. However, it was found that the demands placed on the choke operator were not as great as previously predicted by computer simulations of well-control operations. Nevertheless, considerable hands-on practice may be required for the operator to master the needed special procedures.

A number of new well control procedures developed for the special geometry and low kick tolerance of deep water exploration were experimentally studied under Minerals Management Service sponsorship. These included:

- special shut-in procedures when an influx of formation fluid into the well is detected,
- special procedures for handling gas migration in a closed well,
- special procedures for starting the circulation of a closed well containing formation fluids, and
- special procedures for handling rapid gas expansion in the subsea flowlines connecting the blowout prevention equipment at the seafloor with the surface equipment on the floating drilling vessel.
- special procedures for handling gas trapped in the subsea BOP Stack.

The results of much of the research that was conducted using this well has been presented in a number of technical papers [1-9] presented in the eighties. This work, which was sponsored by MMS, was very timely in that the record water depth for oil and gas exploratory drilling operations increased steadily during the eighties from about 1,500 ft to about 8,000 ft. Deepwater drilling operations were conducted briefly off the Atlantic coast during the eighties. The Gulf of Mexico continues to be an important area of deep water development for the United States. Brazil has also become a leader in the development of oil and gas reserves found in deep water.

DEVELOPMENT OF IMPROVED BLOWOUT PREVENTION SYSTEMS

Between 1984 and 1988, emphasis was shifted in the LSU/MMS program from the development of improved procedures for use in deep water with existing equipment to the development of improvements in the blowout prevention systems. The two major systems that were considered were the Diverter System and the Pressure Control System.

The Diverter System is employed for the shallow portion of a well, before sufficient casing has been set to permit the well to be safely shut-in. Its purpose is to divert the flow of formation fluids away from the rig and rig personnel. MMS personnel had become concerned about a high rate of diverter failure during diverter operations and had recommended that this area be addressed.

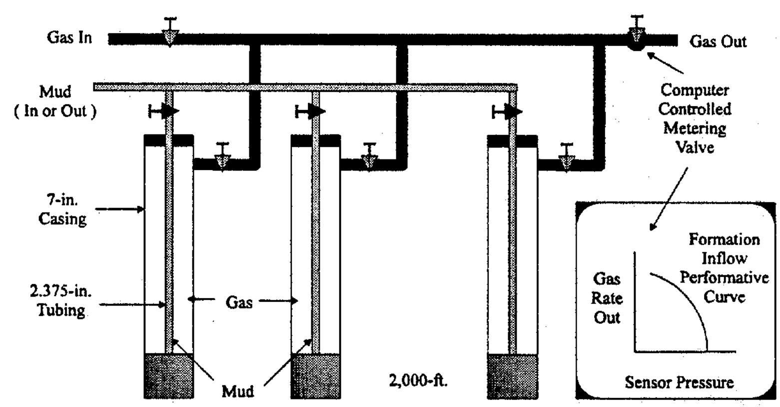


Figure 6 -Gas storage system and formation simulator.

Additional construction at the facility was undertaken to permit a model diverter system to be constructed. A 6-in. pipeline was installed which connects the facility with a natural gas transmission line that operates at 700 psi pressure. Three 2000-ft (610 m) wells were drilled and cased with 7-in., 38 lb/ft N-80 and P-110 casing. These wells were configured to allow natural gas to be compressed as high as 5000 psi for use in well control exercises (Figure 6). Pressurization is accomplished by filling the annulus of the wells with gas from the pipeline, and then compressing the gas by pumping mud down the tubing of one well, forcing the gas into the annulus of the other wells. The fill/compression cycle of one well can be repeated to obtain the final pressure desired. For some experiments, pipeline pressure is adequate and compression of the gas is not required.

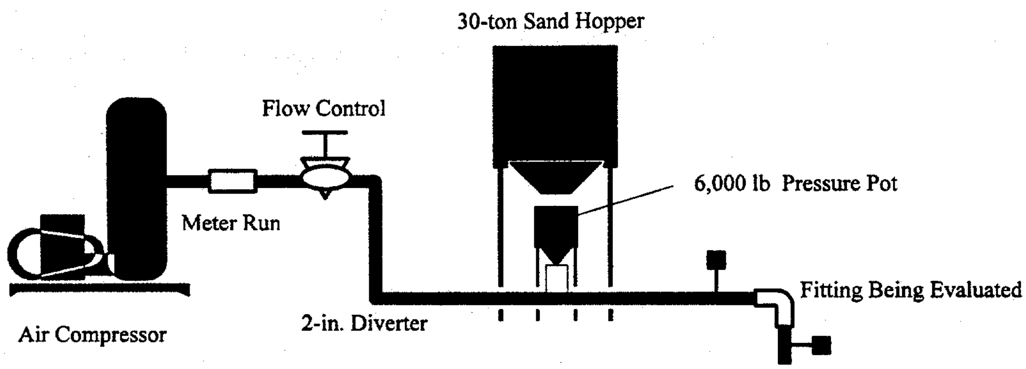
Another well was drilled and cased to 1200 ft (365 m) to allow a model diverter system to be constructed (Figure 7). The diverter was constructed of 6-in., double extra strong pipe that was approximately 80-ft in length. A 7.0626-in. annular blowout preventer manufactured by Hydril is used to close the well and divert the flow through the diverter. The diverter was instrumented with four pressure transducers to provide a record of the multiphase flow pressure behavior during the unloading sequence. The exit of the diverter was above a large earthen pit that was filled with water.

A second diverter system composed of 2-in. pipe was used to study erosion problems due to formation sand being present in the well effluent. Sand was introduced to a gas flow stream from a 6000-lb sand blasting pressure pot. A 30-ton sand hopper was positioned above the pressure pot for loading it with sand. The pressure pot was also located for easy use on the larger 6-in. model diverter system.

Fundamental research on diverter systems was conducted to improve our ability to predict the pressures at various points within a diverter system at different phases of a shallow-gas-flow event and to predict the erosion rates due to the production of sand with the formation fluids. Improved design procedures that considered the conductor casing and diverter as a system were developed. A number of technical papers were presented during the mid to late eighties[10-15] that presented the results of this research. This work was also very timely in that API Recommended Practices and MMS regulations concerning diverter systems were being studied and modified during this time period.

The work on an improved Pressure Control System focused on the possibility for integrating subsurface Measurements-While-Drilling (MWD) technology with an automated well control system. Maintenance of the proper bottom-hole pressure within a small error band is more important for deep-water drilling operations because the margin between fracture pressure and pore pressure is typically much smaller. It was determined that advancements would have to be made in the data transmission rate of MWD systems to allow MWD technology to be integrated into an automated pressure control system.

A horizontal drill pipe flow loop (Figure 8) was installed at the facility to permit testing of mud pulse data telemetry systems under realistic operating conditions. Use of a horizontal system allowed access to the tool without the need to trip pipe from a borehole to gain access to the telemetry device. The 4.5-in., 20 lb/ft API drill pipe was buried at a depth of four feet with the ends located conveniently for access to the mud circulation system. The total length of the system was about 10,000-ft, and provided a excellent means for studying attenuation of the pressure pulses used to encode data and send it to the surface. A larger mud pump was provided by Halliburton for circulating this system.



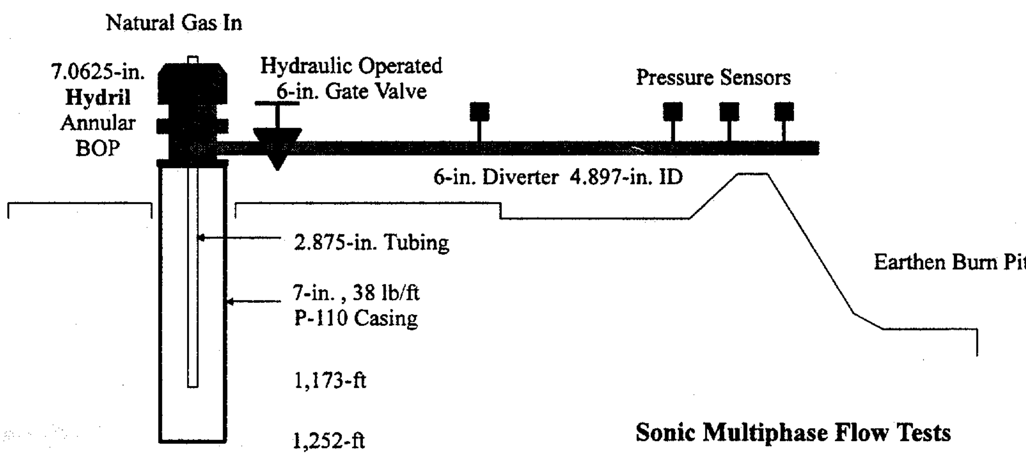


Figure 7 - Scaled diverter model.

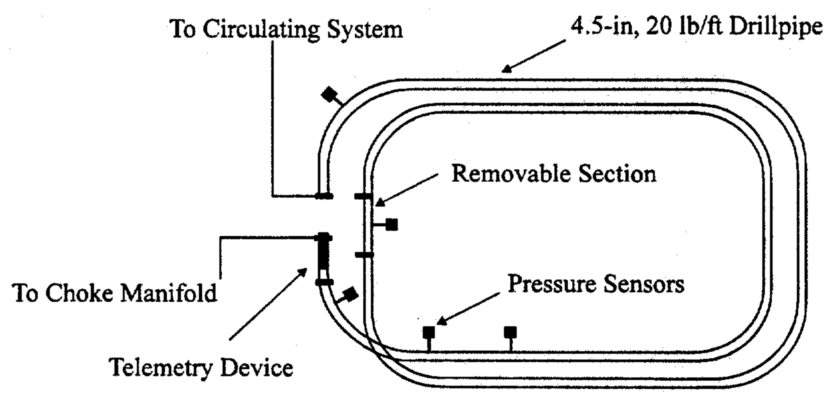


Figure 8 - MWD flow loop.

Basic research was conducted on achieving higher data transmission rates using a new fluidics mud pulser designed by Harry Diamond Laboratory. Work was also done to measure the signal attenuation rate as a function of data transmission rate for different types of mud systems. In addition, process control algorithms were developed for automatic control of the drilling choke and mud pumps during well control operations. Technical papers describing the results of this work were published during the late eighties.[16-18]

INDUSTRY SPONSORED PROJECTS

In addition to the work being sponsored by MMS, several industry sponsored projects were also undertaken during the 1984-88 period. A project sponsored by Tenneco and funded through the Drilling Engineering Association (DEA Project 4) looked at well control problems associated with gas solubility in oil-base muds. Gas solubility and oil swelling due to dissolved gas were measured in several base oils and emulsifiers used to formulate these muds. Similar measurements were also made in several mud formulations. Problems associated with kick detection and with gas cut-mud coming out of solution were also experimentally studied using the research well facility. A related project sponsored by Amoco and funded through the Drilling Engineering Association (DEA Project 7) was also conducted. In this project, down-hole measurements of methane concentration were made during well control operations in both water-base and oil-base muds. A new 6000-ft well was designed and constructed at the LSU facility that would permit down-hole logging tools to be run in the well during well control operations (Figure 9). Results obtained in DEA Project 4 were published during the late eighties.[24-26] However, because of the high costs involved, participants required that data from DEA Project 7 could not be released for several years.

Industry sponsored work on toxicity testing of oil-base muds, on rig fire suppression systems, and on freeze plug formation through injection of carbon dioxide was also undertaken in this period. Most of this work involved testing of proprietary systems developed by others. Some of the fire suppression work was sponsored by the National Fire Center of the National Bureau of Standards and Technology.

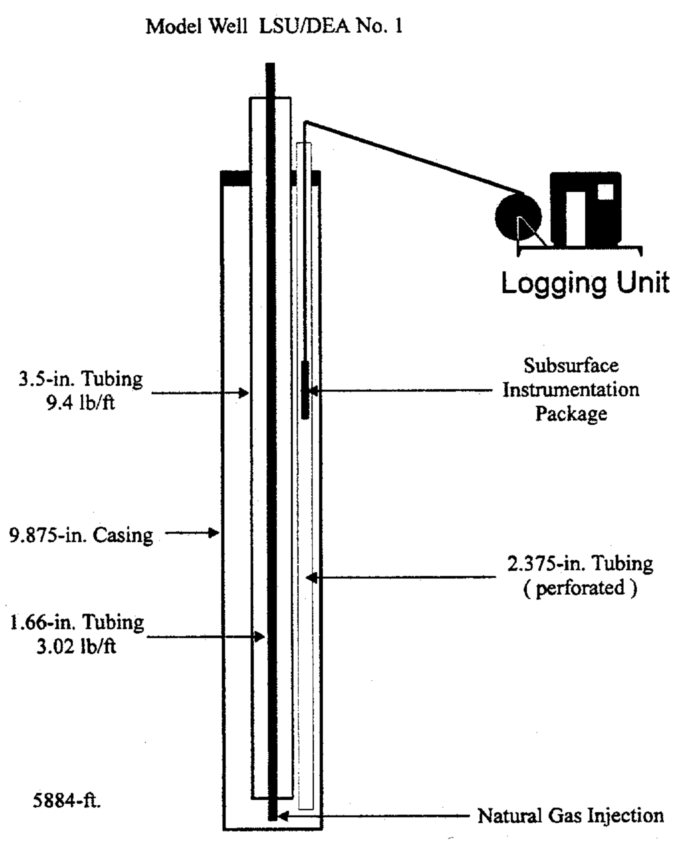


Figure 9 - Research well permitting well logging during well control operations.

IMPROVED CONTINGENCY PROCEDURES

In 1989, the LSU well control research effort began focusing on the development of improved contingency procedures for complications arising during offshore blowout prevention operations. An International Well Control Symposium was held in 1989 to review the results of recent and on-going well-control research and to obtain input for future research. Following this symposium, work on the development of improved diverter systems and pressure control systems continued. The integration of MWD data into an automated pressure control system was demonstrated to be feasible. In addition, correlations developed for the prediction of multiphase sonic exit pressures and for the prediction of erosion rates at bends of a diverter system were successfully extended to larger diameter pipe sizes.[19,20] The verification of our predictive models in near full-scale systems allows them to be applied to field conditions with more confidence. The effect of injected water and/or friction reducing agents as a means of reducing diverter erosion during diverter operations was studied. A computer model was developed to permit the potential application of injected water for a given field situation to be easily determined. The potential field use of a sonic-velocity detector and erosional indicator at the diverter exit was also demonstrated.

Important complications to blowout prevention operations that were identified at the International Well Control Symposium for further study included: (1) well control operations on highly deviated or horizontal wells, (2) well control problems caused by solution, diffusion, and dispersion of formation gas in oil-base muds, and (3) special problems arising after a well is placed on a diverter before it is brought under control.

An inclined annular flow model about 49 ft (15 m) long was designed and constructed to permit basic multiphase flow studies with non-Newtonian drilling fluids. (Figure 10) The model is supported from a 100-ft derrick and permits gas concentration to be determined for various inclination angles, gas rates, and mud rates. This model allowed the development of a valuable database on gas slip velocities and gas concentration that occurs at various points in a highly deviated or horizontal well.[21] Work was also done[22,23] on developing more accurate methods of determining the surface pressures needed to obtain the desired bottom-hole pressure.

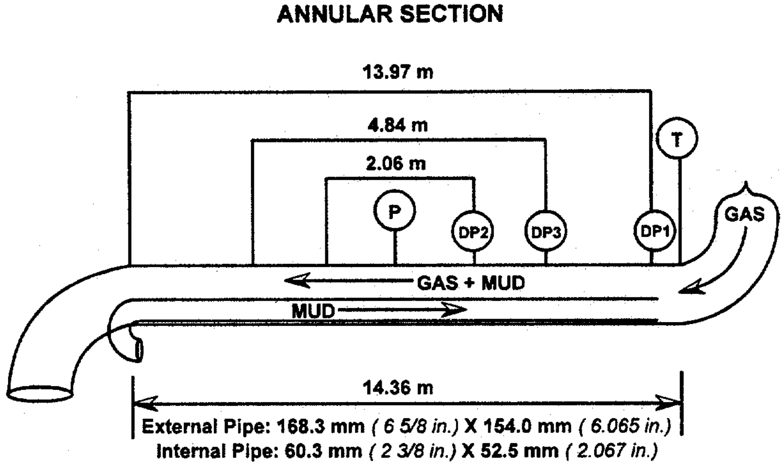


Figure 10 - Annular model for inclined multi-phase flow.

We have also studied some of the special problems that can arise after a well is placed on a diverter. One such problem is designing a dynamic kill to bring the well under control. In many past cases, a dynamic kill had to be attempted with the drill string inserted only partially into the well. The multiphase flow behavior in the bottom portion of the well for these conditions were simulated in our inclined flow loop. The experimental study provided information on how much heavy drilling fluid will fall into the bottom portion of the well, and how much will be blown out of the well for a given operating condition.

Other recently completed projects include (1) a study of the sediment failure mechanisms by which a crater can develop under an offshore structure and erode its foundations, (2) an experimental study of multiphase flow conditions during bull-heading operations, (3) an experimental evaluation of erosion resistant materials for use in diverter systems, and (4) the re-completion of one of our test wells in a new configuration that will better support our planned research and training activities. We are reporting the results of this recent work at this workshop. In addition, several technical papers have recently been prepared to help dessiminate the results of our work to industry. [27-32]

DETECTING AND HANDLING UNDERGROUND BLOWOUTS

In October, 1995, a new five year effort was initiated on well control problems associated with underground blowouts. An underground blowout differs from a surface blowout in that the uncontrolled flow exits the well beneath the surface rather than at some point above the seafloor. The formation fluids enter the well at one point and exit the well at another. The exit point could be a fractured formation, a failed cement seal, a failed casing connector, or a rupture in the casing. Underground blowouts are more numerous than surface blowouts, and sometimes contribute to a surface blowout. A recent paper by Danenberger[33] reported that the fracturing of subsurface formations allowing gas to escape to shallow sediments or to the seafloor was a contributing factor in 24.1% of the surface blowouts occurring on the outer continental shelf from 1971 to 1991.

Salt water flows that occur outside of the conductor casing string are also a severe problem in deep water drilling in some areas of the Gulf of Mexico. In some cases, more than half of the cost of the deep water exploratory well is associated with controlling flows outside the shallow casing strings and getting a satisfactory cement job on these strings. Cratering due to such flows could be a serious hazard to the foundations of a deep water production facility.

The technology of designing a well kill for an underground blowout is not nearly as straightforward or as understood as conventional kick control. Often the well remains under pressure for a long period of time, and the subsurface well conditions are more difficult to determine from the surface pressure. This can lead to an increased risk of personnel error before the underground flow is corrected. The three main control techniques used are (1) bull-heading, (2) a dynamic kill technique for placing a region of heavy mud near bottom, and (3) placing plugging agents such as a barite pill or cement in the well. The design of the well kill is often more by trial and error than through the use of a standard calculation procedure. It has been difficult to develop good well control training modules in the area of underground blowouts because a systematic approach has not yet been defined.

In some cases involving underground blowouts, the problem may never be fully resolved, and an underground flow may continue after the well is abandoned. Such situations are often difficult to detect until a well is drilled at a later time and finds unexpected pressure at a more shallow depth. Significant loss of natural resources as well as potential environmental damage can result from undetected underground flows that continue for long periods of time.

Another problem that is sometimes related to underground flow outside of the production casing is the development of excessive pressure on an annulus between casing strings that is supposed to be sealed. Excessive casing pressure problems can occur on completed wells that are in a producing phase, in addition to problems seen while drilling. After the well is completed, diagnosing the cause of the excessive casing pressure can sometimes be very expensive. In some cases, the operator may request a temporary waiver from MMS requirements concerning the maximum allowable casing pressure seen, or they may request permission to bleed pressure off the casing. The problems and risks associated with bleeding fluids from a casing annulus that is experiencing unexpected high pressures have not been extensively studied.

The high difficulty level of the problems that are being studied will require a multi-year approach. During the current year, members of the research team are conducting work on the prevention, detection, remediation, and post analysis of underground blowouts in drilling operations. In addition, a field study of producing wells in the Gulf of Mexico with excessive casing pressure waivers granted during the past two years will be initiated. A number of recent publications[34-48] have highlighted some of our results obtained since starting our new five year research plan in 1994. Some additional results obtained in this new research area will also be presented during this workshop.

REFERENCES

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2. Mathews, J. L. and Bourgoyne, A.T. : "A Feasibility Study on the Use of Subsea Chokes in Well Control Operations on Floating Drilling Vessels", Journal of Petroleum Technology (May, 1982) and Transactions of the Society of Petroleum Engineers, 1982.

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INTRODUCTION

by

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The MMS has funded well control research at the Louisiana State University since the early 1980's. The current 5-year project includes 12 tasks addressing issues relating to underground blowouts. The long range objective of MMS and LSU through the well control research program is to develop improved methods for detecting and quickly stopping an underground blowout.

One of the research tasks is to study excessive casing pressures in producing wells. The MMS estimates that there are 6000 wells with sustained pressures affecting one or more casing strings. To better examine sustained casinghead pressure concerns and the broader issue of underground blowouts, the MMS and LSU are conveneing a 2-day workshop. The first day of the workshop will be conducted as an extension of the MMS Gulf of Mexico (GOM) Outer Continental Shelf (OCS) Regional Operations Technology Assessment Committee (ROTAC) to discuss sustained casinghead pressure issues. MMS regulations and policy will be presented and openly discussed with industry, as will the results of recent surveys mandated by MMS. Remedial projects and research efforts will also be discussed.

The second day of the workshop will be a review of ongoing research at LSU on well control supported by The Minerals Management Service and by the Oil and Gas Industry. The overall goal of the LSU/MMS research program is to foster technology improvements and safety in the development of new oil and gas reserves from the U. S. Outer Continental Shelf and the 200-mile Exclusive Economic Zone while minimizing the risk to the marine environment and minimizing the waste of our natural resources. The research program has been sponsored under multi-year plans and funded on an annual basis. We are currently starting the third year of a five-year effort focused on underground blowouts in a marine environment. The goals of this portion of the workshop are to:

- Disseminate information about the results of LSU's well control research projects that have been accomplished during the past year,
- Evaluate the completed research tasks and proposed future research,
- Suggest areas of need not currently being addressed, and
- Develop a priority list for the most needed work that should be undertaken during the next academic year.

Workshop participants include MMS representatives from the various OCS regions and from MMS headquarters, industry representatives, and members of the LSU well control research team. Forms are provided to assist the MMS and industry representatives in recording their evaluation and suggestions on the various topics presented.

The first day of the workshop will start with presentations from ROTAC members that review recent problems, current regulatory requirements and operational guidelines, and case histories. This will be followed by a discussion of the best available technology for reducing the occurrence of these problems. Recognized experts have been invited to participate in the technical discussions. Time will be provided for industry input. Operational considerations and the possible need for additional research will also be discussed. The activities of the day will end with a Barbecue sponsored by SWACO and a site visit at the LSU Research & Training Well Facility.

The second day of the workshop will start with presentations from LSU's well control research team that will summarize on-going research efforts and our proposed research theme for the next three years. Projects that are currently being proposed for next year will also be presented. At the end of the presentations, an open session will be held to allow participants to evaluate the proposed research plan, to offer ideas and recommendations, and to help assign priorities to possible future work. A short presentation by Robert Labelle, Chief of the Technology Assessment and Research Branch of MMS, at the Luncheon will bring the participants up-to-date on the overall research and future directions of MMS. The last session will end with an open forum discussion on future research. The meeting will conclude by 4:45 pm.

PRE-REGISTERED WORKSHOP PARTICIPANTS (AS OF 11/18/96)

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Duncan, Richard Research Associate		✓
Kimbrell, Clay Research Associate		✓
Lopes, Clovis Graduate Student		✓
Sandoz, Chris Graduate Student		✓
Scott, Stuart Assistant Professor	✓	✓
Smith, John Graduate Student		✓
Stephens, L. Scott Professor		✓
Manowski, Wojciech Graduate Student		✓
Wojtanowicz, Andrew Professor		✓

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WORKSHOP EVALUATION FORM, DAY 1

Session	Evaluation	of	Workshop	Activity	Comments
	Excellent	Good	OK	Poor	
Sustained Casing Pressure: Review of Problem					
Current Regulatory Requirements and Operational Guidelines					
Current Methods for Analysis and Remediation					
Mechanisms for Long-Term Gas Migration Behind Casing					
Applications of Blast Furnace Slags in Preventing Fluid Migration Behind Casing					
Case History of Well with Sustained Casing Pressure: Volumetric Kill Using Zinc Bromide					
Case History: Abandoning a Well with Sustained Casing Pressure					
Industry Input and Operational Considerations					
Progress Report on Study of BOP Test Frequency					
Status Report- Support "O" Training Regulations					
Site Visit to Research Facility					

GENERAL COMMENTS AND SUGGESTIONS:

Please indicate your category below

- ☐ MMS Headquarters Representative
- ☐ MMS Pacific Region Representative
- ☐ MMS Gulf Coast Region Representative
- ☐ Research Industrial Sponsor
- ☐ Industry Representative

(PLEASE USE BACK OF FORM IF NEEDED.)

WORKSHOP EVALUATION FORM, DAY 2

Session	Evaluation	of	Session		Comments
	Excellent	Good	OK	Not Needed	
Research Program Overview					
Improvements in LSU/MMS Research and Training Well Facility					
Feasibility Study of Dual Density System for Deepwater Drilling					
Finite Element Analysis of Soft Sediment Behavior During Leak-off Tests					
Density, Strength, & Fracture Gradients for Shallow Marine Sediments					
Drill String Safety Valve Test Program					
Low Torque Drill String Safety-Valve Design					
Post Analysis of Recent Blowouts and Near Misses					
Automated Detection of Underground Blowouts					
Cement Slurry Vibration as Method for Prevention of Flow Behind Casing					
Overall Program					

GENERAL COMMENTS AND SUGGESTIONS:

SUGGESTED TOP RESEARCH PRIORITIES:

Please indicate your category below

- ☐ MMS Headquarters Representative
- ☐ MMS Pacific Region Representative
- ☐ MMS Gulf Coast Region Representative
- ☐ Research Industrial Sponsor
- ☐ Industry Representative
- ☐ Other:____________________

Please rate your hotel accomadations:

- ☐ Highly Recommended
- ☐ Recommended
- ☐ Satifactory
- ☐ Unsatifactory
- ☐ Poor

Name of Hotel: ____________________

Sustained Casing Pressure on Producing Wells

November 19, 1996

Gulf of Mexico OCS Region
Regional Operations Technology Assessment Committee (ROTAC) Workshop

Agenda

- MMS presentations - focus discussion
- Remedial actions
  - » field applications
  - » case studies
  - » research at LSU
- Information exchange - technical and operational issues; policy

ROTAC

- Regional Operations Technology Assessment Committee
- Review technology advancements
- Identify operational needs
- Review/prioritize research proposals
- Operational issues/workshops
  - » e.g., *Shallow Gas Flows While Waiting on Cement (1995)*

Workshop Objectives

- Summarize MMS SCP data
  - » 8100 wells w/SCP; affecting 11,500 casings
  - » 13,600 active completions (12/95)
- Highlight current MMS regulations and policy relating to SCP
- Identify and discuss concerns
- Discuss some key remedial projects
- Identify MMS contacts

Lagniappe

- Progress Report - *Study of BOP Test Frequency*
  - » Bill Hauser, MMS
- Status Report - *Subpart O Training Regulations*
  - » Joe Levine, MMS
- Barbecue and Site Visit of Research Well Facility

Sustained Casing Pressure: A Review of the Problem

Lee Fowler
MMS
Lake Jackson District Office

Sustained Casing Pressure Review

May 18, 1995 Letter to Lessees
Response

MMS

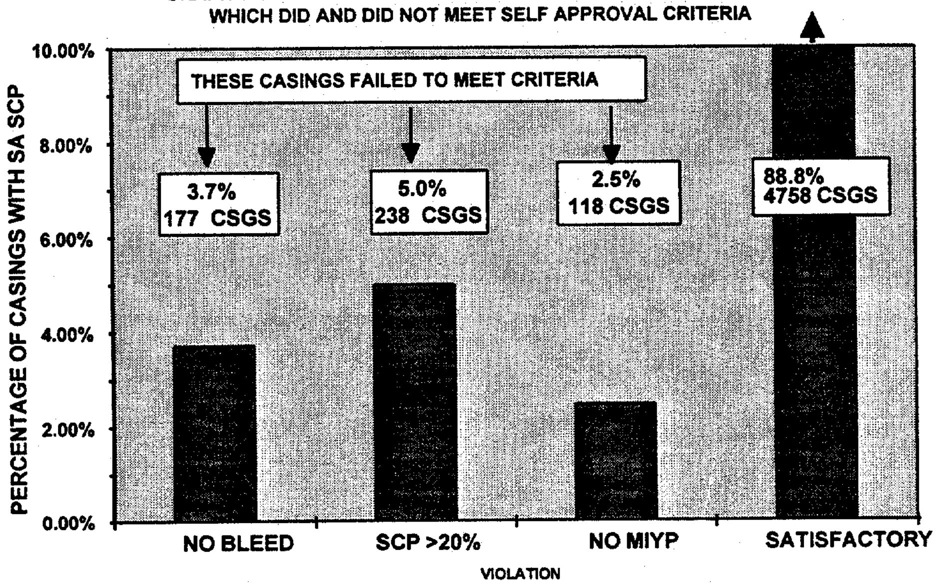
GENERAL RESULTS

- INFORMATION RECEIVED ON
  - 3041 WELLS WITH 4758 SCP CASINGS
- INCREASED PREVIOUS INFORMATION:
  - WELLS 6111 TO 8122
  - PRESSURED CASINGS 6819 TO 11498
- DENIALS ISSUED 14

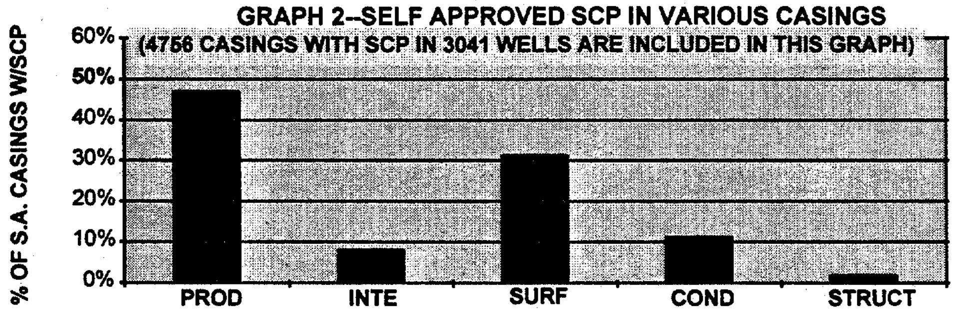
GENERAL RESULTS

- INFORMATION RECEIVED ON
  - 3041 WELLS WITH 4758 SCP CASINGS
- INCREASED PREVIOUS INFORMATION:
  - WELLS 6111 TO 8122
  - PRESSURED CASINGS 6819 TO 11498
- DENIALS ISSUED 14

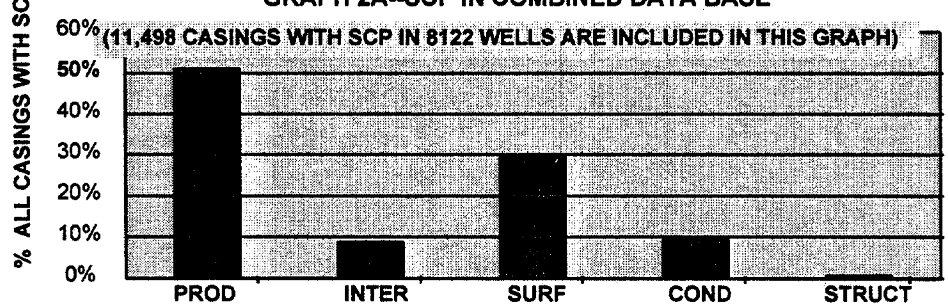
GRAPH 1--PERCENT OF REPORTED CSGS WITH SELF APPROVED SCP WHICH DID AND DID NOT MEET SELF APPROVAL CRITERIA



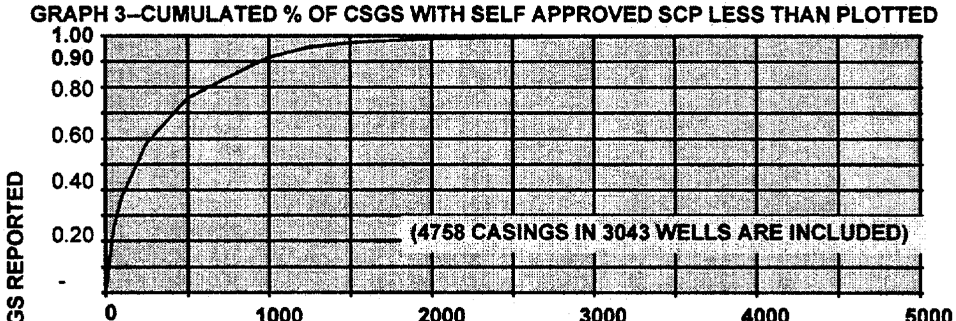
GRAPH 2--SELF APPROVED SCP IN VARIOUS CASINGS



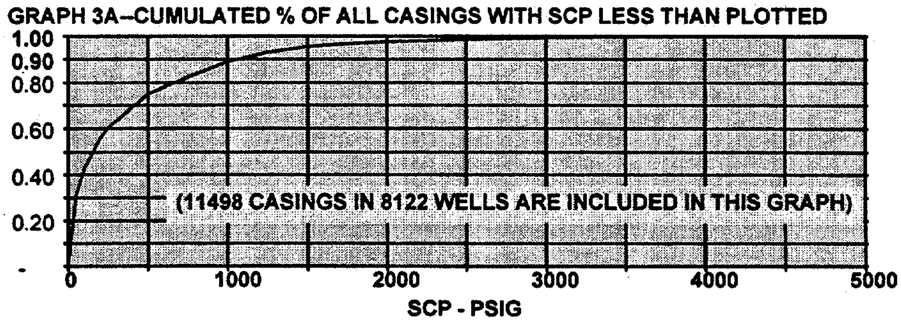
GRAPH 2A--SCP IN COMBINED DATA BASE



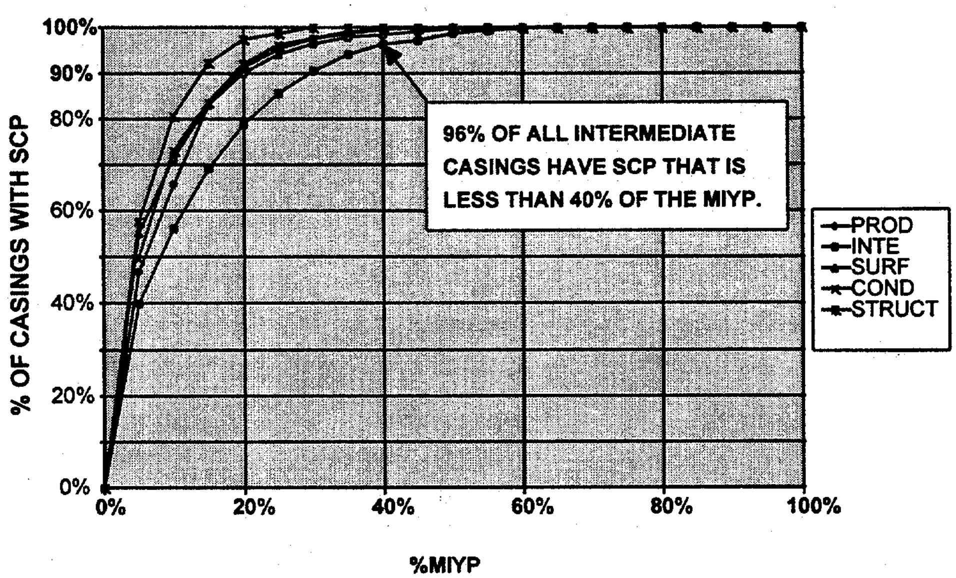
GRAPH 3--CUMULATED % OF CSGS WITH SELF APPROVED SCP LESS THAN PLOTTED



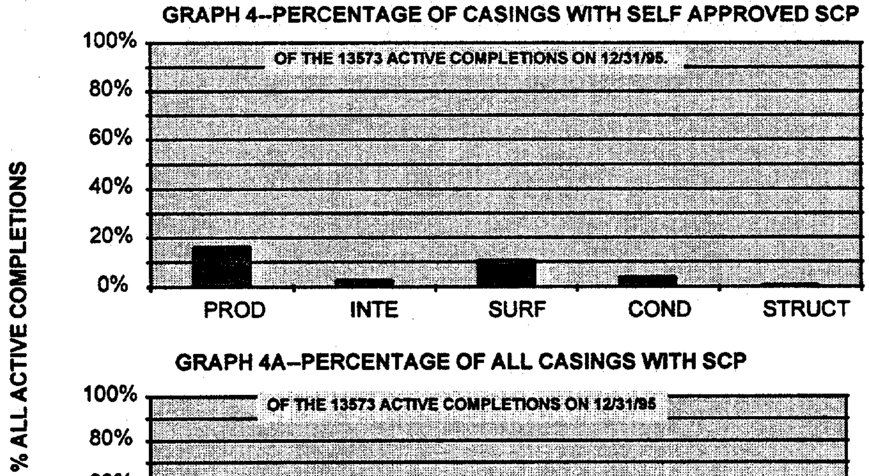
GRAPH 3A--CUMULATED % OF ALL CASINGS WITH SCP LESS THAN PLOTTED



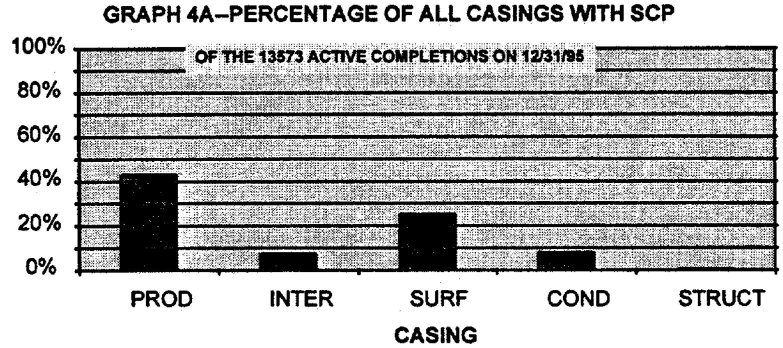
GRAPH 3A(bu2)--SCP DISTRIBUTION AS % MIYP FOR CASINGS



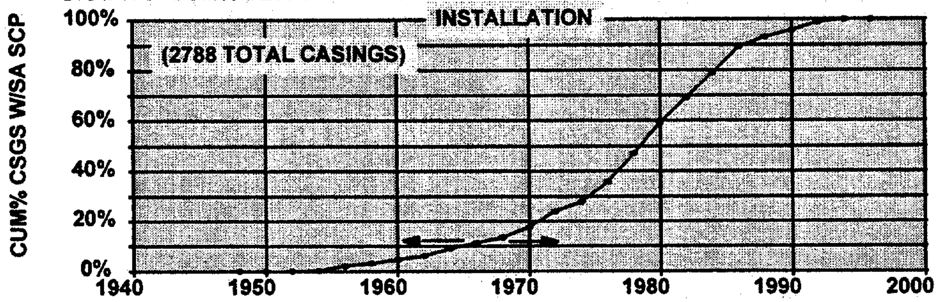
GRAPH 4--PERCENTAGE OF CASINGS WITH SELF APPROVED SCP



GRAPH 4A--PERCENTAGE OF ALL CASINGS WITH SCP



GRAPH 5--CUM% SELF APPROVED SCP CSGS VS YR PLATFORM APPROVED FOR INSTALLATION



GRAPH 5A--CUM % ALL SCP CSGS VS YR PLATFORM APPROVED FOR INSTALLATION

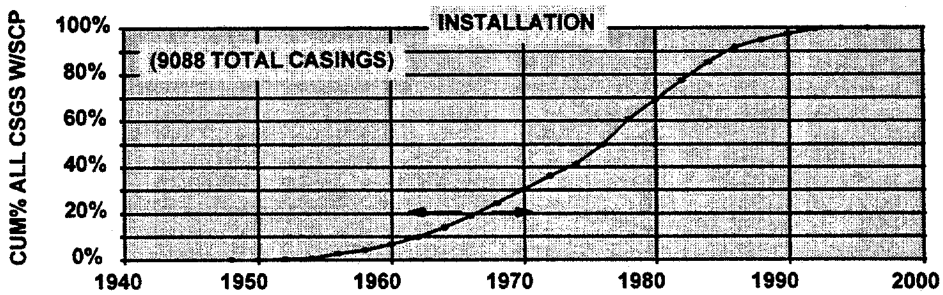


TABLE I

TYPE OF PRODUCTION-CIRCA DEC 1995

<u>SELF APPROVED SUSTAINED CASING PRESSURE WELLS</u>

		SCP CASINGS-STATUS OF WELLS			
TYPE OF PRODUCTION	WELLS	TOTAL CSGS	ACTIVE	SHUT IN	OTHER
GAS	787	1104	587	517	0
OIL	757	1191	841	350	0
SULFUR	30	52	5	47	0
SERVICE	5	7	7	0	0
ABAND, TEMP ABAND, AND S. I.	678	1018	0	1018	0
UNDESIGNATED	784	1386	0	0	1386
		TOTAL	ACTIVE	SHUT IN	UNK
TOTAL	3041	<u>4758</u>	1440	<u>1932</u>	1386

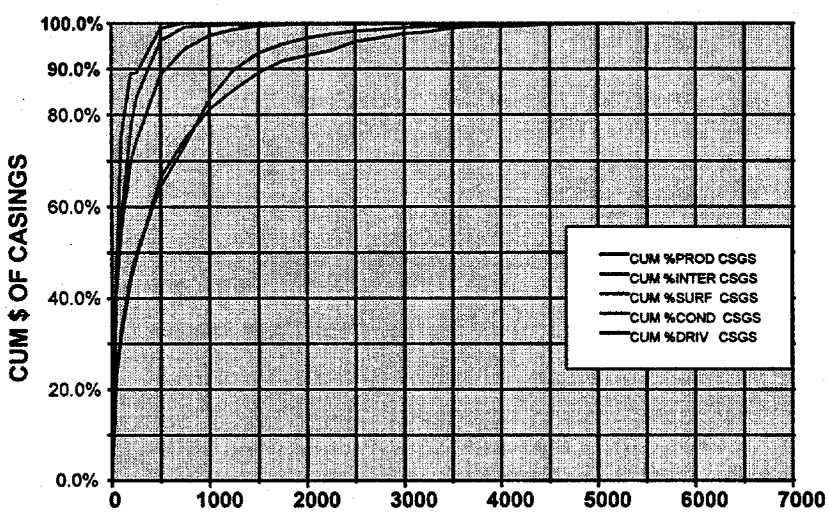
<u>ALL SUSTAINED CASING PRESSURE WELLS</u>

		SCP CASINGS-STATUS OF WELLS			
TYPE OF PRODUCTION	WELLS	TOTAL CSGS	ACTIVE	SHUT IN	OTHER
GAS	2888	4192	1352	2840	
OIL	2850	3959	2172	1787	
SULFUR	184	266	12	254	
SERVICE	5	6	6		
ABAND, TEMP ABAND, AND S. I.	357	578		578	
UNDESIGNATED	1838	2497			2497
		TOTAL	ACTIVE	SHUT IN	UNK
TOTAL	8122	<u>11498</u>	3542	<u>5459</u>	2497

CONCLUSIONS

- This effort has added to our information about SCP and resulted in some improvement in safety.
- The number of violations was small, and repetitions of this type of study should be made only on a 5-year basis.
- **Tubing design** process for offshore wells needs to be improved.
- **Cement design** process for offshore wells also needs to be improved.
- The SA SCP wells appear to have a better chronology (relative to the design criteria of the platforms where they are located) than the wells in combined data base.
- A substantial portion of the efforts of both industry and the MMS to assure safety of wells with SCP is spent on wells that are in a non-productive status (SI, TA, PA).

Graph 3A(bu1)-- PRESSURE DISTRIBUTION OCCURRENCE IN EACH CASING



SUSTAINED CASING PRESSURE--PROD CSG

SUSTAINED CASING PRESSURE REVIEW

I. **INTRODUCTION**
   A. LTL of May 18, 1995--Requested information on "Self Approved" (SA) status wells
      1. Pressure < 20% MIYP
      2. Bleed Zero in <24 hrs thru ½ inch needle valve
   B. Purpose to summarize analysis of the data received

II. **SCP DATA BASE**
   A. Foxpro File--1988 to 1996
   B. Annual Departures, Indefinite Departure, and Denials
   C. Total 6111 wells in the data base with 6819 pressured casings
   D. Made it into an Excel File

III. **LTL DATA BASE**
   A. Circa May - Dec 1995
   B. SA casings with SCP
   C. **DATA BASE CONSTRUCTION**
      1. Original data (some 12000 records) was on printed reports.
      2. Requested disk copies of data and received disk data on some 10500 records

      (Disk data was in several formats, Excel, Lotus, Word Perfect etc, and was arranged differently for each operator.)

      3. Was able to enter the disk data in 1/4 of the time required for manual entry of data from the printed reports.
   D. Totals:
      1. Reported: 4332 wells with 8222 casings in the data base
      2. Refined : 3041 wells with 4758 casings in the data base
         a. Removed casings with 0 pressure
         b. Removed casings with self imposed (gas lift) pressure
         c. Removed duplicate information
   E. Made it into an Excel File

IV. **COMBINED DATA BASE**
   A. Combined the Excel Files
   B. Removed duplications--kept the most recent data for each casing
   C. 8122 wells with 11498 pressured casings in the data base
   D. Survey added 2011 net wells and 3276 net casings to our information on SCP--net increase of 30% in our information

V. **RESULTS**
   A. **Graph 1** - Violations of SA Criteria

1. 415 casings (8%) did not meet SA Criteria
2. 118 casings (2.5%) did not contain MIYP data
3. Letters written to 30 Operators [NOTE: NEED TO CK THIS NUMBER]
    a. Request additional information
    b. Grant annual departure where appropriate
    c. Issued 14 denials

B. **Graph 2** - Distribution of Pressure Between Casings
1. 48% of casings with SA SCP have pressure on the production casing (Mostly result of tubing leaks)
2. 52% of casings with SA SCP have pressure on other casings (Mostly result of micro annulii in the cement of the next casing)
3. **Graph 2A** for combined analysis confirms this trend

C. **Graph 3** - Distribution of Pressures Seen in All Casings
1. Casing burst is not a problem in most cases.
2. **Graph 3A** for combined analysis confirms this trend
3. **Graph 3A(bu2)** for combined analysis shows
    a. More than 90% of the scps were below 40% of the miyp.
    b. The Self Approval criteria of 20% miyp encompassed more than 80% of the casings.

D. **Graph 4** - Casings with SCP - Percent of Active COM Wells
1. 16% of active s have SA SCP on Prod Casing
2. 16% of active s have SA SCP on Others (Intermediate, Surface, Conductor, or Structural Casings)
3. **Graph 4A** for combined analysis indicates the seriousness of this trend:
    a. About 42% of active s have SCP on Prod
    b. About 42% of active s have SCP on Others
4. TUBING DESIGN NEEDS TO BE IMPROVEMENT
    a. SCP
    b. Laving reserves because "CAN'T AFFORD TO REPLACE TUBING"
5. CEMENT DESIGN NEEDS TO BE IMPROVED
    a. SCP
    b. SOME HIGH PRESSURES ARE A HAZARD

E. **Graph 5** - Year Platform Was Approved For Installation for Casings With SCP
1. 11% of Casings With SA SCP are on platforms designed on 25 yr Wave Height Critieria.
2. **Graph 5A** shows that 21% of casings (in the more inclusive combined data base) are on platforms designed on 25 yr Wave Height Criteria

F. **Table I** - Type Production - Self Approved SCP Wells
1. Numbers of oil and gas wells with Sustained Pressure are about equal
2. **Table IA** - Same Data for Wells in Combined Data Base
3. **In both tables:** "A significant effort is being spent by Operators and the

MMS in maintaining a large number of shut in wells with SCP."

VI. CONCLUSIONS

A. The information from this effort has resulted in some improvement in safety. The number of violations was small, and repetitions of this type of study should be made only on a multi-year basis.

B. Tubing design process for offshore wells needs to be improved.

C. Cement design process for offshore wells also needs to be improved.

D. The SA SCP wells appear to have a better geographal location (relative to the design criteria of the platforms where they are located) than the wells in overall data base.

E. A substantial portion of the efforts of both industry and the MMS to assure safety of wells with SCP is spent on wells that are in a non-productive status (SI, TA, PA).

Current Regulatory Requirements and Operational Guidelines

Sustained Casing Pressures on Producing Wells Workshop
November 19, 1996

Performance Requirements

- Performance Requirements
  - » 30 CFR 250.3
- Use of new or alternative techniques
  - » equal or better safety, performance, protection
  - » prior written approval from MMS required
- Departures
- Incorporating industry standards and recommended practices

SCP Regulatory Background
(1988 - Present)

- 1988: Consolidated regulations
  - » 30 CFR 250.87 - monitor all annuli
  - » concerns: number of wells and reporting
  - » MMS and OOC initiated discussions
  - » SCP study (OOC) commenced
- 1989: SCP Policy
  - » OOC/MMS meetings (study results)
  - » streamlined departure process

SCP Regulatory Background
(1988 - Present)

- 1991: Letter to Lessees (LTL)
  - » reflecting 1989 policy
- 1994: LTL
  - » supersedes 1991 LTL
  - » clarify policy
    - reporting and data submittal requirements
    - time to respond to denial (30 vs. 15 days)
    - unsustained pressure; subsea wells

SCP Regulatory Background
(1988 - Present)

- LTL dated May 18, 1995
  - » further clarification
  - » MMS SCP departure on a well basis
  - » data collection for wells with SCP<20%

Current Practice

- January 13, 1994, LTL sets policy
- Drive/Structural pipe excluded
- Notify District Supervisor
  - » day following date SCP discovered
- Diagnostic requirements
  - » new SCP
  - » change in SCP (200 psi - PROD and INT; 100 psi others)

Data Requirements

- Request departure if:
  - » SCP > 20% MIYP, or
  - » SCP does not bleed to zero in 24 hrs
- Pressure vs. time - 1 hr increments
  - » bleed-down and 24-hour build-up
- ALL CASING annuli w/SCP
- Pre-bleed pressure
- Well status; flowrates; SITP; FTP

Departures

- Granted on a Well Basis
  - » does not present a hazard to personnel, platform, formation, or the environment
  - » allow wells to continue producing
- Annual
  - » e.g., SCP > 20% AND bleeds to zero psi
- Indefinite/Life of completion
- Special Cases

Departure Processing

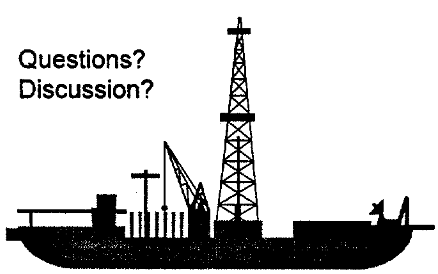
- TAOS Section
  - » issue departures; letter or verbal
  - » coordinate policy decisions
- District
  - » initial reports of SCP
  - » follow-up actions to denials
- Special remedial projects addressed by both offices

Future

- Continue/expand remedial projects
- Additional studies?
  - » results of ongoing research
  - » follow-up actions
- Periodic surveys?
  - » similar to May 1995 LTL
- Update existing policy?

LSU/MMS Well Control Workshop

Questions?
Discussion?



Current Methods for Analysis and Remediation

Dr. Stuart Scott
LSU

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Gulf of Mexico OCS Region
1201 Elmwood Park Boulevard
New Orleans, Louisiana 70123-2394

IN REPLY REFER TO:

In Reply Refer To: MS 5220

MAY 18 1995

Gentlemen:

This Letter to Lessees and Operators (LTL) serves to summarize briefly the historical evolution of the Minerals Management Service (MMS) sustained casinghead pressure (SCP) policy and to update information regarding all wells with SCP on the Gulf of Mexico (GOM) Outer Continental Shelf (OCS).

In August 1991, MMS sent a letter to all GOM OCS lessees that identified policy changes concerning SCP and thereby initially clarified the provisions contained in 30 CFR 250.87(c). These changes streamlined the reporting procedures for wells with SCP conditions. The intention of this initial policy was twofold: to permit the continued production from existing completions, subject to specific monitoring requirements, and to allow for the retention of records at the lessee's field office. This policy also addressed wells with SCP's that were less than 20 percent of the minimum internal yield pressure of the affected casing and that bled to zero pressure through a 1/2-inch needle valve in 24 hours or less. A "self-approved" category for wells with SCP's that met these criteria did not have to be submitted to MMS for approval of a departure. This policy was revised in a letter, dated January 13, 1994, that provided further clarification regarding wells with SCP, the time retention of field records, and the criteria to be used to determine unsustained casing pressure due to thermal effects.

Previous LTL's have resulted in confusion regarding which casing strings are to be reported in a departure request. For clarification, the MMS approval of a SCP departure request is granted on a <u>well-basis</u>. The operator shall list all casing strings with SCP in the departure request, and positively note that the remaining annuli do not have SCP.

It is recognized that with the passage of time everything is subject to change; therefore, the condition of a well may further deteriorate throughout its producible life. Even though casing pressure may not increase to a level that triggers diagnostic testing, the condition(s) that are contributing to the casinghead pressure may have worsened over time, and pressure on the affected casing annulus may not be able to be bled to zero as in the past.

The MMS currently has limited information on wells with SCP's that fall into the former indefinite departure or the new "self-approved" category. Although the fact that these wells were noted to have pressure may have been appropriately reported to the respective MMS District office, the results of subsequent diagnostic testing by the operator for the most part were <u>not</u> provided to MMS.

Therefore, each operator shall submit a status report to this office within 90 days of the date on this letter. The report is to provide an updated listing of all wells with self-approved SCP. This listing shall include the most recent pressures on <u>all annuli</u> with SCP. Operators are free to design their own report form, but must include the information outlined in the enclosed sample data sheet. This effort will help MMS update the official records for wells with SCP, assuring the industry that MMS is relying on the same data for assessments of departure requests. The diagnostic data requested are critical to the safety analysis of a well with SCP. If a diagnostic test has not been conducted within the past 12 months on a well that has SCP, a test should be conducted prior to submitting this status report. Those wells with sustained casinghead pressure less than 100 psi on the conductor or surface casing, or 200 psi on the intermediate or production casing are exempt from the diagnostic testing requirements established above.

It is recognized that bleeding fluid from a casing annulus for a SCP diagnostic test could potentially result in increasing the magnitude of the pressure problem. Operators are encouraged to replace liquids recovered during bleed-down diagnostic testing with a fluid that is of equal or greater density, and to replace gas with appropriate mud or packer fluid.

Please contact Doug McIntosh at (504) 736-2529 should you have any questions regarding this effort.

Sincerely,

Donald C. Howard

Donald C. Howard
Regional Supervisor
Field Operations

Enclosure

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
Gulf of Mexico OCS Region

In Reply Refer To: MS 5221

Jan 13 1994

Gentlemen:

This letter serves to inform lessees operating in the Gulf of Mexico Outer Continental Shelf of the current policy concerning sustained casing pressure according to the provisions of 30 CFR 250.87. The following policy supersedes our last Letter to Lessees and Operators dated August 5, 1991, and is intended to streamline procedures and reduce burdensome paperwork concerning the reporting of sustained casing pressure conditions and the approval process for those wells that the Minerals Management Service (MMS) will allow to be produced with sustained casing pressure.

1. All casinghead pressures, excluding drive or structural casing, must be immediately reported to the District Supervisor. This notification by the lessee, to the District Supervisor can either be in writing *or* by telephone, with a record of the notification placed in the record addressed in Paragraph 5 below, by the close of business the next working day after the casing pressure is discovered.

2. Wells with sustained casinghead pressure that is less than 20 percent of the minimum internal yield pressure of the affected casing *and* that bleed to zero pressure through a ½-inch needle valve in 24 hours or less may continue producing operations from the present completion with monitoring and evaluation requirements discussed below.

A diagnostic test that includes bleeddown through a ½-needle valve and buildup to record the pressures in at least 1-hour increments must be performed on each casing string in the wellbore found with casing pressure. The evaluation should contain identification of each casing annulus; magnitude of pressure on each casing; time required to bleed down through a ½-inch needle valve; type of fluid and volume recovered; current rate of buildup, shown graphically or tabularly in hourly increments; current shut-in and flowing tubing pressure; current production data; and well status. Diagnostic tests conducted on wells that meet the conditions described in Paragraph 2 above do not have to be formally submitted for approval.

3. Wells having casings with sustained pressure greater than 20 percent of the minimum internal yield pressure of the affected casing *or* pressure that does not bleed to zero through a ½-inch needle valve, must be submitted to this office for approval. The information submitted for consideration of a sustained casing pressure departure under these conditions should be the same as described in the above paragraph.

4. The casing(s) of wells with sustained casinghead pressure should not be bled down without notifying this office except for required and documented testing. If the casing pressure from the last diagnostic test increases by 200 psig or more in the intermediate or production casing, or 100 psig or more in the conductor or surface casing, then a subsequent diagnostic test must be performed to reevaluate the well. Notification to this office is not necessary if the pressure is less than 20 percent of the minimum internal yield pressure of the affected casing *and* bleeds to zero through a ½-inch needle valve. The recorded results of the subsequent diagnostic test must be kept at the field office. However, the results of this test must be submitted to this office for evaluation of the conditions as described in Paragraph 3 apply.

5. Complete data on each well's casing pressure information need only be retained for a period of 2 years, except that the latest diagnostic information must not be purged from the overall historical record that must be kept. Casing pressure records must be maintained at the lessee's field office nearest the OCS facility for review by the District Supervisor's representative(s).

6. The previous approval of a sustained casing pressure departure is invalidated if workover operations, as defined by 30 CFR 250.91, commence on the well. Also, operations such as acid stimulation, shifting of sliding sleeves, and gas-lift valve replacement require diagnostic reevaluation of any production or intermediate casing annulus having sustained pressure.

7. Unsustained casinghead pressure may be the result of thermal expansion or may be deliberately applied for purposes such as gas-lift, backup for packers, or for reducing the pressure differential across a packoff in the tubing string. Unsustained casinghead pressure which is deliberately applied does not need to be submitted to this office. Unsustained casinghead pressure, as the result of thermal expansion, greater than 20 percent of the minimum internal yield pressure of the affected casing *or* does not bleed to zero through a ½-inch needle valve needs to be submitted to this office with either of the following information:

a. The lessee must report the casing(s) pressure decline (without bleeddown) to near zero during a period when the well is shut in, or

b. With thoroughly stabilized pressure and temperature conditions during production operations, the lessee may bleed down the affected casing(s) through a ½-inch needle valve approximately 15–20 percent, and obtain a 24-hour chart which shows that the pressure at the end of the following 24-hour period is essentially the same as the bleeddown pressure at the start of the 24-hour period while production remains at a stabilized rate.

8. Subsea wells with remote monitoring capability must be monitored, analyzed, and reported as described above. If the casing valve(s) must be operated manually the monitoring, analyzing, and reporting frequency is 2 years at a maximum.

9. Should a request for a departure from 30 CFR 250.87 result in a denial, the operator of the well will have 30 days to respond to the MMS District Office with a plan to eliminate the sustained casinghead pressure. Based on well conditions, certain denials may specify a shorter time period for corrections.

If there are any questions regarding this matter, please contact Mr. B.J. Kruse at (504) 736-2634.

Sincerely
[signed] D.J.Bourgeois
Regional Supervisor
Field Operations

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
Gulf of Mexico OCS Region

In Reply Refer To: MS 5221

Aug 05 1991

Gentlemen:

This letter serves to inform lessees operating in the Gulf of Mexico Outer Continental Shelf of policy changes concerning the provisions of 30 CFR 250.87(c). These changes are initiated to streamline reporting procedures and reduce burdensome paperwork concerning the reporting of sustained casing pressure conditions.

Current policy dictates that the lessee must perform bleed down and build up diagnostic tests on wells which exhibit sustained casing pressure. The diagnostic test results are submitted to this office and are evaluated based on the specific conditions found. Wells with casings having pressures that are less than 20 percent of the minimum internal yield pressure of the affected casing *and* bleed to zero pressure during a bleed down and build up diagnostic test are approved for continued operation of the present completion with monitoring requirements. Effective immediately, diagnostic tests conducted on wells which qualify under these conditions will no longer have to be formally submitted for approval. If such a sustained pressure condition exists, the lessee shall, however, adhere to the following conditions:

1. Monitor the well(s) *monthly* and maintain records with regard to casing pressure(s) observed and diagnostic tests performed on the well(s). These records must be made available for Minerals Management Service (MMS) inspection at the lessee's field office nearest the OCS facility or at other locations conveniently available to the District Supervisor.

2. If the casing pressure from the last diagnostic test increases by 200 psig or more in the intermediate or production casing, or 100 psig or more in the conductor or surface casing, then a subsequent diagnostic test must be performed to reevaluate the well. The results of the subsequent diagnostic test must be recorded at the field office and submitted to this office for evaluation if either of the following conditions apply:

   a. The casing pressure has increased to greater than 20 percent of the minimum internal yield pressure for the affected casing, or

   b. During the performance of the diagnostic test the casing pressure fails to bleed to zero.

The information submitted should contain the identification of the casing annulus with pressure, magnitude of such pressure, time required to bleed down, type of fluid and volume recovered, current rate of buildup, and current shut-in and flowing tubing pressure.

3. Such approval is invalidated if workover operations commence on the well(s).

4. The casing(s) should not be bled down during this period without notifying this office, except during required diagnostic tests conducted pursuant to condition No. 2 above.

Information on wells having casings with sustained pressure greater than 20 percent of the minimum internal yield pressure of the affected casing *or* pressure which does not bleed to zero, must continue to be submitted to this office for approval.

If there are any questions regarding this matter, please contact Mr. [*corrected:* B.J. Kruse at (504) 736-2634—*Ed.*]

Sincerely,
[signed] D.J. Bourgeois
Regional Supervisor
Field Operations

CURRENT METHODS FOR ANALYSIS AND REMEDIATION OF SUSTAINED CASING PRESSURE

by

Stuart Scott and Adam T. Bourgoyne, Jr.

Petroleum Engineering Department
Louisiana State University
Baton Rouge, Louisiana 70803-6417

OBJECTIVE

A large number of producing wells in the OCS develop undesirable and sometimes potentially dangerous sustained pressure on one or more casing strings. The objectives of ongoing research by LSU in this area are to:

1. Compile information from the MMS and operators on the magnitude of the sustained casing pressure problem;
2. Determine the possible causes of sustained casing pressure;
3. Compile information from the literature and from operators on procedures for correcting or managing existing problems and reducing the number of future problems; and,
4. Assisting in the development of new technology for reducing the number of future problems.

INTRODUCTION

The invention of portland cement by Joseph Aspdin has allowed major advances in our civilization because of its low cost, strength, and ability to set under water. It has been used by the oil and gas industry since the early 1900's as the primary means of sealing the area between the open borehole and the casing placed in the well. Shown in Figure 1 is a typical well completion showing the placement of cement to seal off the interior of various casing strings from the subsurface formations exposed by the drill bit. Ideally, the well of Figure 1 should show pressure only on the production tubing. Gauges on all of the casing strings should read zero if:

- the well is allowed to come to a steady-state flowing condition, and
- the effect of any liquid pressurization due to heating of the casing and completion fluids by the produced fluids is allowed to bleed off by opening a needle valve.

Only a small volume of fluid has to be bled in order for the casing pressure to fall to atmospheric pressure if the pressure was caused by thermal expansion effects. If the needle valve is closed and the well remains at the same steady-state condition, then the casing pressure should remain at zero. If the casing pressure returns when the needle valve is closed, then the casing is said to exhibit sustained casing pressure (SCP). In some cases the pressure can reach dangerously high values. The Minerals Management is concerned about wells on the Outer Continental Shelf

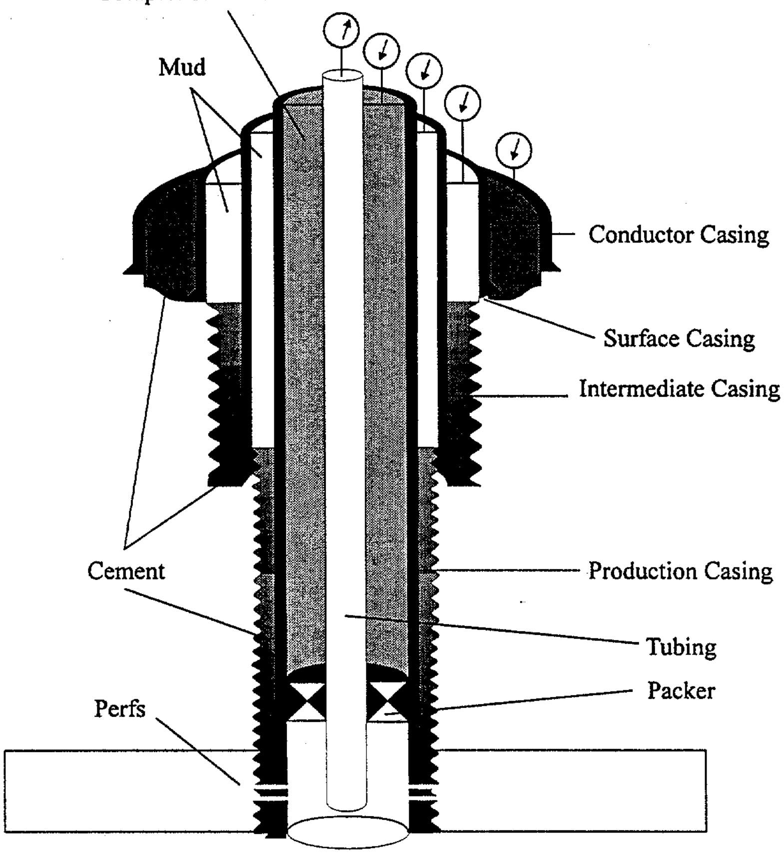


Figure 1 - Simplified Well Schematic

(OCS) that exhibit significant sustained casing pressure because of its responsibility for worker safety and environmental protection as mandated by congress.

At present, any amount of sustained casing pressure seen on one or more casing strings of a well (excluding drive pipe and structural casing) is viewed as significant enough to trigger notification of MMS. Structural and drive pipe is excluded because it is recognized that gas of biogenic origin is sometimes encountered in the shallow sediments and can cause insignificant pressures on the drive and structural casing. SCP also triggers a requirement that records of the casing pressures observed be kept available for inspection in the operator's field office.

Strictly speaking, regulations under 30 CFR 250.57 state that wells with SCP should not be produced until the problem is corrected. However, provisions are made for a departure from 30 CFR 250.57 to be obtained. As part of the effort to streamline government and reduce burdensome paperwork, MMS developed guidelines under which the offshore operator could self-approve a departure for 30 CFR250.57. Departure approval is automatic as long as the SCP is less than 20% of the minimum internal yield pressure and will bleed down to zero through a 0.5-in. needle valve in less than 24 hours.

For wells with more than 100 psi on the conductor or surface casing, or more than 200 psi on the intermediate or production casing, MMS also requires operators wanting to qualify for self approval to perform a specified diagnostic procedure and maintain records of the results of the diagnostic tests. The diagnostic tests must be repeated whenever the pressure is observed to increase (above the value that triggered the previous test) by more than 100 psi on the conductor or surface casing or 200 psi on the intermediate or production casing. However, if at any time the casing pressure is observed to exceed 20% of the minimum internal yield pressure of the affected casing, or if the diagnostic test shows that the casing will not bleed to zero pressure through a 0.5-in. needle valve over a 24 hour period, then the operator is expected to repair the well under regulations 30 CFR 250.87. If the operator does not believe that it is economically justifiable to

repair the well, and also believes that the well can be operated safely in its current condition, a request for a departure from 30 CFR 250.87 can be made. If the request for a departure is denied, the operator normally has 30 days to correct the problem. When a departure is requested, MMS begins tracking the well's casing pressure data in an SCP database. There are currently over 6000 wells in the SCP database that do not meet the criteria for self-approval.

Sustained casing pressure is a difficult operational problem that in extreme cases can compromise the integrity of the well. This study reveals how wide-spread this problem is for the petroleum industry, particularly in the U.S. Gulf of Mexico. Surveys with operators have shown intensive efforts are underway to understand and correct this problem. Remediation efforts to date have had mixed results. This report details where SCP problems are encountered, the suspected causes, how SCP problems are diagnosed and monitored, and current methods being used for remediation and prevention. First, several case histories are examined to demonstrate the seriousness of this problem.

CASE HISTORIES OF PROBLEMS CAUSED BY SCP

The principal concern of sustained casing pressure is loss of well control. Migration of high pressure to the surface puts the well in an uncontrolled situation and puts personnel, the environment and natural resources at risk. Outer casing strings are not rates to sustain high pressure and therefore do not represent a barrier to flow under these conditions. The failure of one or more deeper casing string can cause a cascade of casing failures as subsequent strings are exposed to high pressures from deep formations. A sustained casing pressure indicates a flow path has been established through cement or casing. The pressure values measured often increase slowly over time and the technology does not exist at present to predict how fast this pressure will increase or to what level will it ultimately reach. The potential problems that can occur in wells exhibiting SCP is best understood by reviewing several example case histories.

Case 1 - Two wells on a platform developed SCP on the production casing about six years after the wells were completed. The operator requested a departure indicated that the shut-in tubing pressure was about 3400 psi and the minimum internal yield on the casing was about 6900 psi. Thus the operator argued that a safe operation could be maintained. A departure was granted by MMS and the well continued to be produced. Two years later, the well began blowing out from the annulus between the production casing and surface casing. The well was out of control for 46 days and released an estimated 600 MMscf of gas and 3200 bbl of condensate during this period. Pollution washed up on about 4 miles of beach. The well cratered and the platform tipped over. The blowout was killed using a relief well and the platform and wells had to be abandoned and removed. The wells were plugged and cut off below the mudline.

Case 2 - Five years after a well was put on production, SCP was seen on the production casing and a departure was requested. The departure was granted for a period of one year. At the end of this year, the operator requested that the departure be renewed, reporting that the SCP on the production casing ranged from 1400 psi to 1800 psi. MMS granted the renewal with a diagnostic monitoring program in place to periodically bleed down the pressure to determine the rate of pressure buildup. About six months later, the SCP began fluctuating and bubbles were seen below the platform. The underground blowout was confirmed in one of the wells that had been stuck and sidetracked during drilling operations. The foundation below one of

the platform legs was eroded and the platform began to shift and settle. All of the wells on the platform were temporarily plugged and work proceeded on repairing the platform and killing the underground blowout. A relief well was needed to kill the blowout. This work was eventually successful, with about 250,000 cubic yards of fill sand being needed to fill the crater around the platform leg. The wells were returned to production after about a year of blowout control and remediation work.

Case 3 - About four years after the well was drilled, the well began to flow mud, gas, and water from the annular space between the surface casing and the conductor casing. Some of the wells had SCP on the production casing. All of the six wells within the leg of the platform containing the flowing well were killed with mud. It was noted that the flow stopped when the SCP on an adjacent well was bled down from about 700 psi. The flow path was thought to be from the production casing of one well, into a shallow water sand, and up the surface casing/conductor casing annulus. A number of wells had to be abandoned and replacement wells drilled as a result of this problem.

Case 4 - Soon after the well was completed and put on production, the operator requested a departure from MMS for SCP on the intermediate casing of 4600 psi, which was about 46% of the minimum internal yield point. When the departure was requested, it was thought that the casing pressure could have been due to thermal expansion. Eighteen months later, work was done on the well to determine why the production rates were lower than expected. Temperature and TDT logs were run and a BHP survey was made. It was determined that an underground blowout was in progress with holes in the tubing, production casing, and intermediate casing. Flow was exiting into a salt water sand below the surface casing. About two months were required to kill the underground blowout, and the well was plugged and abandoned. Some damage was done to the platform foundation, and some settlement of the platform occurred.

SCP DATABASE

Information on wells granted departures by the MMS has been compiled into a database and a new user interface has been created. The database contains 6,049 individual records. We have attempted to divide the wells in the SCP database into two main categories. Wells that have SCP only on the production casing are assumed to have a mechanical problem such as tubing leaks, gas lift pressure, thermal expansion, applied pressure and injection pressure (see Figure 2). The second category includes wells that have pressure on outer casing strings. Wells having

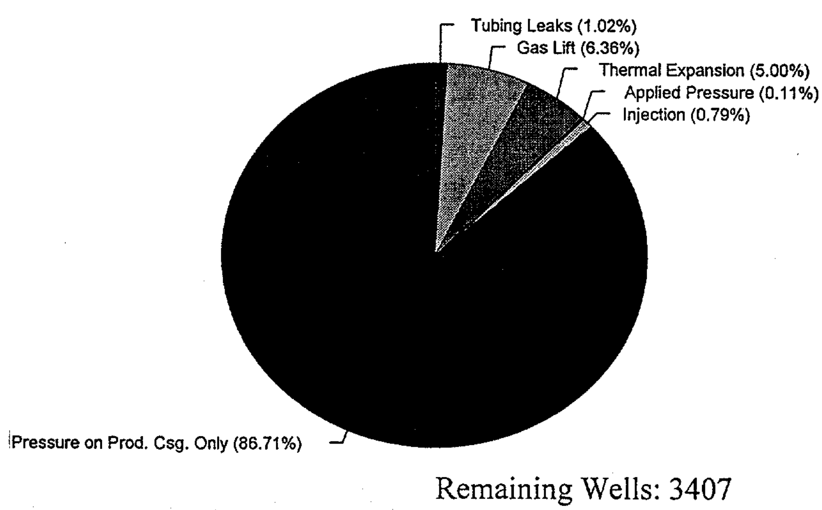


Figure 2: Breakdown of Records Removed from SCP Database

pressure only on the production casing can generally be more easily repaired than wells with pressure on outer casing strings. The second category of wells was felt to need the greatest study. The breakdown of wells falling into this category is shown in Figure 3.

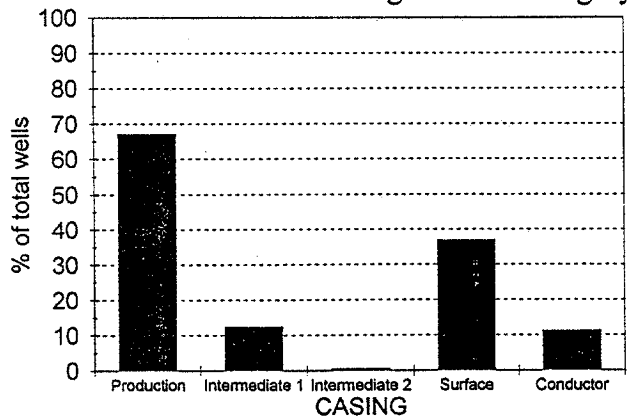


Figure 3: Breakdown of Remaining Wells

After this removal process, 3,407 wells remained which were not self-approved and for which an MMS departure was requested. Figure 4 shows a breakdown of where the wells with unexplained sustained casing pressure are located. The information shown is the total number of wells in an area that are effected and also a normalized percentage of the wells in a given area that are effected.

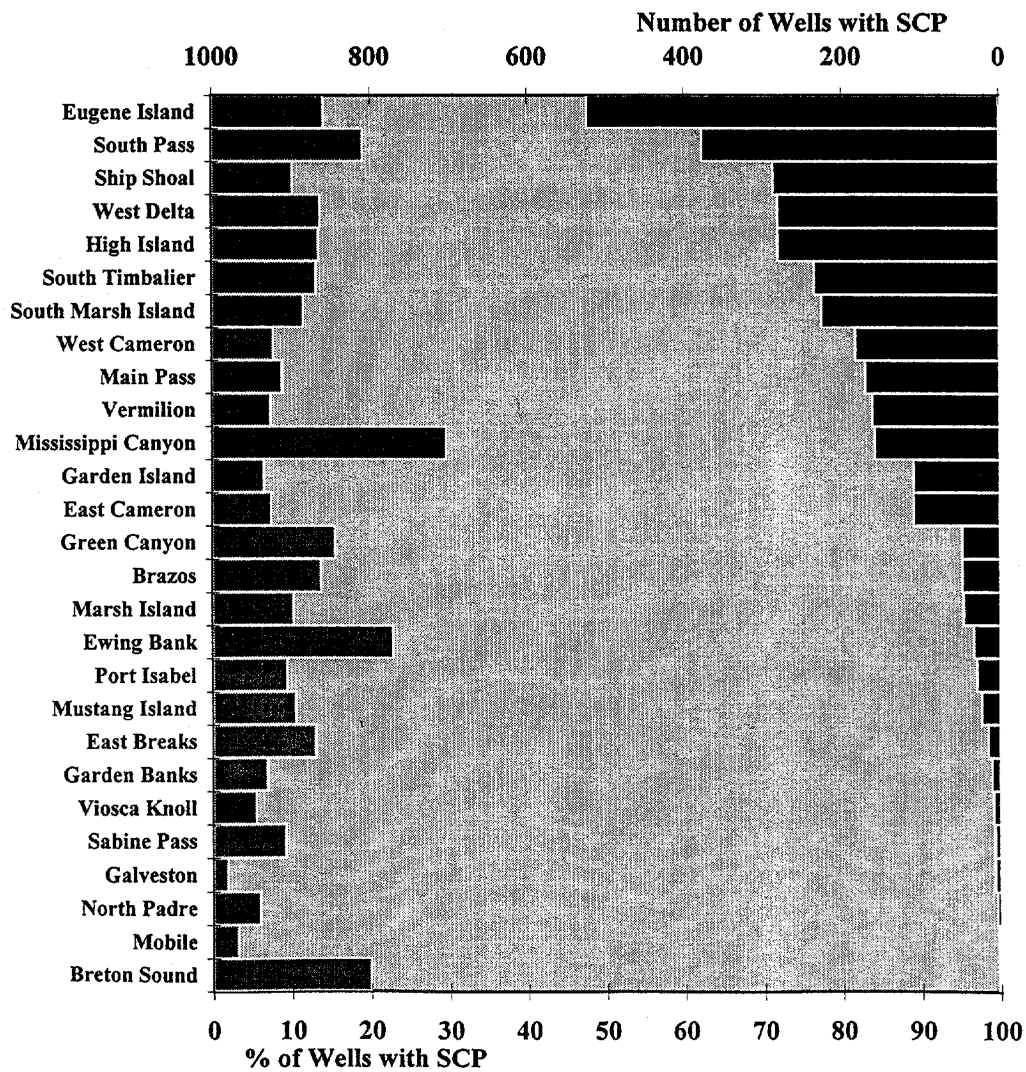


Figure 4: OCS Gulf Region Wells Effected by SCP

SUSPECTED CAUSES OF SUSTAINED CASING PRESSURE

Casing pressure increase due to thermal expansion is a normal occurrence whenever well production rates are changed significantly. These thermal induced effects can be distinguished from SCP in that they rapidly bleed-off to zero pressure and do not persist when the well is produced in a continuous fashion. While it is often difficult to determine the precise cause of sustained casing pressure, the likely causes can be divided into three primary groups: 1) poor primary cement; 2) damage to primary cement after setting; and, 3) casing leaks.

1) Poor Primary Cement. The primary cement job can be compromised in several ways to provide flow paths for gas migration. The most common problem occurring during primary cementing is the invasion of gas into the cement during the setting process. As cement gels it losses the ability to transmit hydrostatic pressure. During this period, fluids (water and/or gas) can invade the cement and form channels. This flow of formation fluids can be from the pay zone to the surface or can be cross-flow between zones of differing pressure. This type of short term fluid migration problem often leads to long term zonal isolation problems and SCP. Also, if substantial thickness of mud cake develops during the drilling process and is not removed prior to cementing, the formation/cement bond may not develop.

2) Damage to Primary Cement. Even a flawless primary cement job can be damaged by operations occurring after the cement has set. This damage can result in formation of a micro-annulus that will allow gas flow to the surface or to other zones. One of the first means of damaging cement is the mechanical impacts occurring during tripping drill collars, stabilizers and other tubulars. These mechanical shocks will play some role in weakening the casing-cement bond. Changes in pressure and temperature result in expansion and contraction of the casing and cement sheath which do not behave in a uniform manner due to the greatly differing thermal and mechanical expansion properties of metal and cement. This can result in the separation of the casing from the cement. These thermal and pressure effects have been the focus of several recent research projects. Increasing and decreasing pressure of the internal casing string was considered by Jackson and Murphey (1993) and a recent investigation by Goodwin and Crook (1990) considered both pressure and temperature effects.

   A number of common completion activities produce a sizable increase in internal casing pressure. Casing pressure tests are routinely conducted to confirm the competency of each string. Pressure tests are also performed prior to perforating, fracturing and after setting packers or bridge plugs. High pressures are also experienced during acidizing, fracturing, and cementing operations. In previous years, most Gulf of Mexico formation completion operations were performed at pressure below the fracturing gradient. In the past few year, the Frac Pack technique has radically changed the way many offshore wells are completed. For this operation, internal casing pressure well above the fracturing pressure is required as shown in Figure 5. This has the effect of increasing by several thousand psi the pressures experienced during well stimulation operations. These increases in the internal casing string pressure has the effect of expanding the internal casing string and compressing the cement sheath. When the pressure inside the casing is reduced, the cement may not experience full elastic recovery, resulting damage to the casing/cement bond creating a small micro annulus when this high pressure is released. Chevron researchers (Jackson & Murphey, 1993)

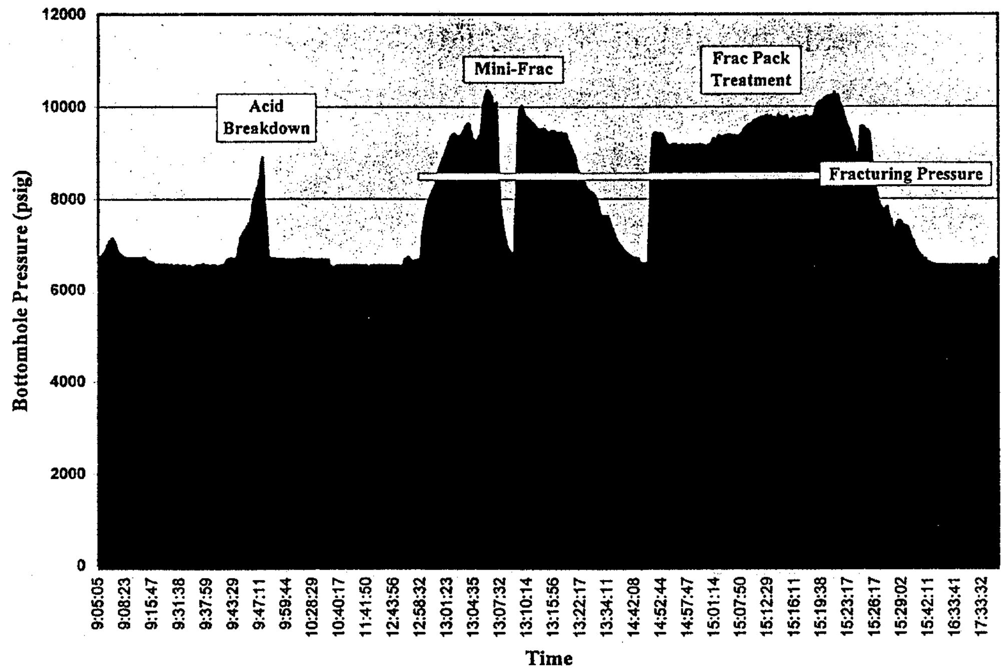


Figure 5: Typical Ship Shoal Frac Pack Treatment

conducted experiments that examined the effect of increasing internal casing pressure. In this work, the cement was set with an internal casing pressure of 1,000 psi and then pressurized and depressurized to examine the effect of increasing internal casing pressure such as during pressure testing. A micro-annulus developed resulting in gas flow for after a cycle to 8,000 psi followed by a depressurization to 1,000 psi. The micro annulus remained active whenever internal casing pressure was below 3,000 psi (Figure 6)

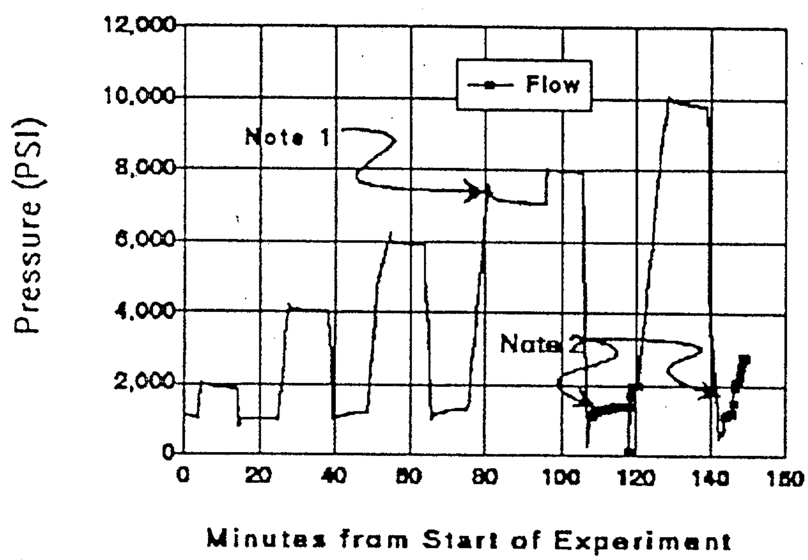


Figure 6: Effects of Increased Casing Pressure (after Jackson & Murphey, 1993)

Decreasing the internal casing pressure is also common during completion and production operations. Operations such as underbalanced perforating, circulation operations, gas-lift operations or from the simple reduction in reservoir pressure due to depletion all reduce internal casing pressure on the primary production string. Use of a lighter packer fluid or lighter muds during drilling a deeper zone may also produce periods of lower pressure in the internal casing than when the cement was allowed to set. So pronounced is this effect that wells are often pressurized prior to running CBL's to obtain a better identification of the location of cement in the annulus. Chevron (Jackson & Murphey, 1993) also performed experiment examining the effects of decreasing internal casing pressure. In this case, the cement was set at an internal pressure of 10,000 psi. Reduction of internal pressure to 3,000 resulted in a flowing micro- annulus that remained active whenever internal casing pressure was dropped below 4,000 psi. (Figure 7)

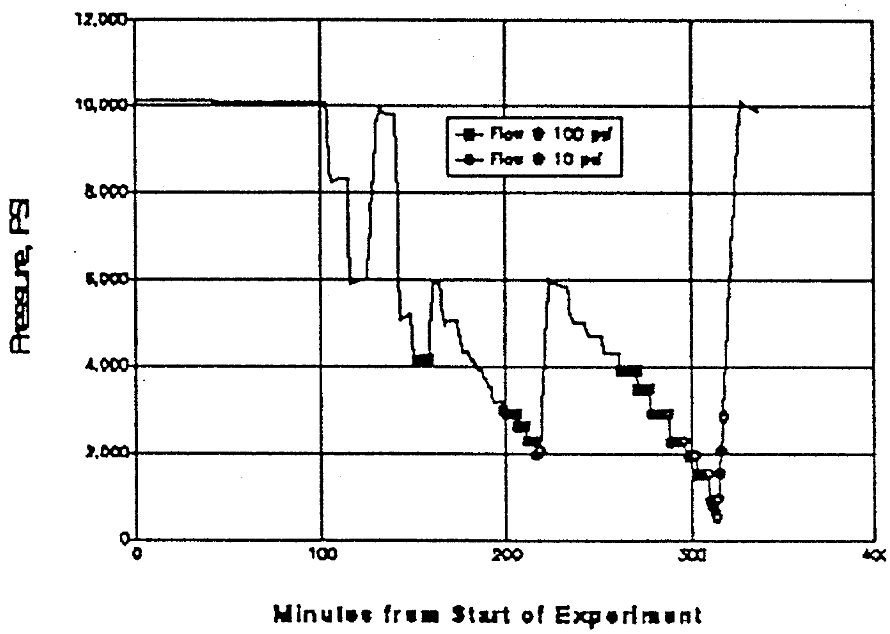


Figure 5: Effects of Decreased Casing Pressure (after Jackson & Murphey, 1993)

3) <u>Casing and Tubing Leaks</u>. A less common cause of high sustained casing pressure is the leakage of pressure from an inner casing and/or tubing string. These leaks can result from a poor thread connection, corrosion, thermal-stress cracking or mechanical rupture of the inner string. Leaks can often be identified by varying the pressure in the inner string and observing the effected to string to determine if the pressure responds in a similar fashion. In extreme cases, it may be possible to identify a tubing leak from routine production data when plotted in backpressure form. Tubing and casing leaks are more often too small for identification from production data and pressure testing is often used.

WELL MAINTENANCE AND DIAGNOSTIC PROCEDURES

Engineering analysis of sustained casing pressure is a data driven process that has thus far been limited by the success of obtaining quality indicative data. In other cases, available data is not collected because a clear use has not yet developed. Some of the sources of data that can be used are:

1) Fluid Sample Analysis - The weight and composition of the fluid that flows from the well during pressure bleed-off operations can yield valuable information regarding the density of the annular fluid and the source of the behind pipe influx of fluids.

2) Well Logging - When behind casing flows are significant, noise and temperature logs can provide information regarding the fluid entry point. Oxygen activation is a cased hole tool that can also provide information regarding fluid flow behind casing.

3) Monitoring Fluid Levels - Due to the difficulties presented by the annular geometry and the 90 degree turns in the wellhead, many convention methods of fluid level determination cannot be utilized. Some operators report success in shooting fluid levels in the annular space using a conventional acoustic test.

4) Pressure Testing - Tubing and production casing leaks can often be identified by pressure testing. Application of surface pressure on inner casing strings may also allow determination of what flow path the invading fluids are flowing.

5) Bleed-Down Performance - The process of bleeding-off pressure from an effected annulus presents one of the best opportunities to obtain information about the annular volume, gas content and channel/micro annulus flow capacity. This operation is normally performed through a fix size (1/2") needle valve and the liquid recovered is also measured. In some cases, an orifice tester is utilized to also measure upstream pressure and allow calculation of effective gas production rate.

6) Wellhead Maintenance - The point of communication from one casing string to another can sometimes be through the wellhead. This was observed by one operator where SCP in the outer 9 5/8" string (3,222 psi) communicated with the 7" casing through a small leak in the wellhead resulting in a SCP of 1,755 psi. In this case, periodic application of grease to the wellhead seals eliminated the problem.

REMEDIATION AND MITIGATION PROCEDURES

A number of methods have been developed in an attempt to eliminate or reduce the pressure once a sustained casing pressure is observed.

1) Do Not Bleed-Off Pressure. The procedure of periodic bleeding of casing pressure is perceived by many operators to only exacerbate the problem. There is some evidence to support this perception. Some have documented cases that show a trend of increasing sustained pressure for wells that have been repeatedly bleed to atmospheric conditions. The fluid bleed-off is often gas, foam, or a light weight (<9.0 ppg) fluid. Therefore, this process effectively reduces the hydrostatic pressure and can potentially increases the influx of gas or light weight fluids into the annulus unless equal weight fluids are replaced. Many are in favor of changing requirements to bleed excess casing pressure to zero to obtain a sustained casing

pressure waiver. Bleeding to a pressure greater than atmospheric if also preferred by some operators.

2) Bleed-Off Pressure. Some wells are cemented to the surface, severely limiting the remediation methods that can be applied. In these cases the volume of gas reaching the surface is extremely small and continuous bleeding-off of surface pressure may be an effective means of mitigating the risks of casing burst. If the high pressure zone feeding the annulus is small, continuous bleeding may deplete this zone and eliminate the SCP altogether. The bleed-off procedure normally involves flowing against a fixed size needle valve at sonic conditions.

3) Lubricate in Weighted Brine. At present, most Gulf Coast operators are examining this method. The concept it to replace the gas and liquids produced during the pressure bleed-off process with a high density brine such as zink bromide. Several operators have reported a reduction in surface casing pressures from the methods. One operator was able to drop the pressure on the 7" by 10 3/4" annulus from 800 psig to 650-700 psig in one well and is planning to apply this procedure to five additional wells in the fall of 1996. Another company has developed a "stair-step" procedure that entails bleeding small amounts of light weight gas and fluid from the annulus and lubricating in zinc bromide brine. This process of systematically increasing annular fluid density has reduced surface casing pressure in several wells. Occasionally, pressures will increase as a new "gas bubble" migrates to the surface, however, the trend is toward lower casing pressures. Special equipment is normally required to inject brine at these extremely low rates (sometime measured in 5-10 quarts per day). While this procedure has been applied for over two years in some wells there have been reversals in the trend of decreasing surface annulus pressures.

4) Circulation of Weighted Brine or Mud. The extremely small volume of fluid that can be lubricated into the annulus has generated interest in developing a method of circulating a higher density fluid to a depth of 1,000 ft. While this has not yet been implemented, several operators and service companies are working on design to use in wells that are not cemented to surface. This method would insert a small diameter string into the annulus to allow circulation to some depth. The 90 degrees turn from the wing valve into the annulus the one of the largest obstacles to the method. Wellheads, with angled annular inlets are being considered to reduce this problem in future wells. If insertion of a circulation sting can be achieved, it provides the opportunity displace lighter weight fluids from the annulus and replace them with a weighted brine or mud.

5) Inject Sealing Fluid. In some cases, injectivity can be established into the effected annulus. In the past, some operators have injected cement or resin to attempt to plug the flow path to the surface. Unfortunately, this approach may satisfy regulatory requirements by eliminating indication of surface pressure, but may mask increasing pressure in the annulus just below the surface in the same casing string.

6) Squeezing. Cutting the casing and squeezing cement is normally considered as a last resort effort. This is do to the low success rate of this type of operations (<50%) and also to the extreme costs. Both block and circulation squeezes have been attempted. These procedures involve perforating or cutting the effected casing string and injection of cement to plug the channel or micro-annulus. The success rate of these procedures is low due to the difficulty in establishing injection from the wellbore to the annular space. As an example of the cost and

success rate of this procedure, one operator reported spending over 20 million dollars on seven wells. This work lasted 13 months in which the casing was cut, milled and cement squeezed. Even after this Herculean effort some of the wells are still reporting sustained casing pressure at the surface.

7) Casing Leak Repair. If the effected casing is accessible, internal casing patches can be used to repair a leak. This device is normally run on elective line and can patch localized leaks.

PREVENTION METHODS

The widespread occurrence of sustained casing pressure has prompted interest in preventing problems through use of new drilling and completion techniques. The following techniques are currently being reported by operators and in the literature:

1) New Cementing Formulation and Practices. Recently, new techniques and cement formulations have been proposed to improve quality of the primary cementing job. Reciprocation, rotation and decentralized rotation of casing during setting may all aid in reducing gas migration through the setting cement. A new technique has been proposed and is actively being tested by Texaco in which the cement is vibrated to improve the cement's ability to achieve zonal isolation. Mud systems are also being developed to minimize the thickness of the mud cake or to incorporate the mud cake into the cement.

2) Annular Casing Packer. From a view point of satisfying regulatory requirements, excess casing pressure at the surface can be eliminated in new wells by mechanical means through use of a packer in the effected annulus. This technique (Vrooman et al., 1992) received one of the 1992 Petroleum Engineering International Meritorious Engineering Awards. In most cases, this technique effectively eliminates gas and pressure migration to the surface. Excess pressure can remain trapped under the packer and may still represent a risk to the integrity of the well.

3) Internal Pressure Considerations during Completion and Production. Strong evidence exists that repeated and extreme cycling of the internal casing pressure weakens the cement sheath thereby creating a micro-annulus path for gas flow. Although some reduction in tubing pressure is inevitable due to reservoir depletion, steps can be taken to minimize unnecessary pressure cycling of the casing. For example, casing integrity tests can be limited to only the necessary pressure and not some arbitrary percentage of rated burst pressure. In the small percentage of wells experiencing tortuosity during fracturing operations, steps can be taken to lower the treating pressure. Also, packer fluids and lead fluids in cementing operations can be designed to assist in maintaining internal casing pressure at a reasonable level.

SUMMARY AND CONCLUSIONS

This study has established the problem of sustained casing pressure on producing wells is more wide spread than previously indicated. Operators are using a number of techniques to remediate the problem and while achieving some isolated success, the results in general are poor. New evaluation techniques are required to determine the best course of action for mitigating SCP. Methods must be developed to determine if the pressure observed can be effectively bleed-off over time or if other measures are required.

RECOMMENDATIONS FOR FURTHER WORK

1. Work with operators to participate on-site during the bleed-off operation. Collect pressure/rate data during both the bleed-off and buildup phases to improve characterization of the flow channel.
2. Develop a simplified model for predicting fluid migration under a wide variety of remediation methods. This would include bleed-off, lubrication of high density brines and injection of muds or resins. The model could separate the thermal effect from the behind pipe effects.
3. Develop improve data gathering and diagnostic tests for wells ...A new methodology is proposed for analyzing the bleeding off and buildup of sustained excess casing pressure. Based on an analysis of these results, recommendations can be made on the most effective method of treating casing pressure. The testing procedures, analysis method and proposed treatment recommendations are detailed below.
4. Perform experimental and modeling investigation of gas migration through nearly set cement which will examine new cement formulations and procedures such as casing vibration.

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Annular Gas Migration

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New Orleans La.

Types of Gas Migration

- Flow Through Unset Cement
- Flow Caused by Mud Channels
- Flow Through Micro-Channels

Two Theories of How Gas Flow Occurs

- Percolation Through Unset Cement
- Flow Through Permeability of Unset or Set Cement

Flow Through Permeability

- All Cements have Permeability 10 md to 0.001 md
- Permeability Flow is Described by Darcy's Equation

Note: Flow Rate of Gas can be Calculated Given Permeability and Other Constants

Air Permeability of Cements at 230° F

Slurry	K (Air)
1.) (Latex)	< 0.01
2.) (GasStop) (GasBan)	0.05
3.) (Microbond HT)	0.36

Conclusion

Significant Gas Flow Will Not Occur Through Permeability of Cement

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Gas Migration Occurs By Flow of Gas Through Channels in Set Cement Created by Percolation Through Unset Cement

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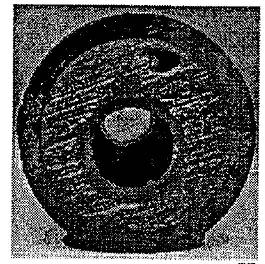
Gas Migration Through Unset Cement

- **Laboratory testing was conducted with SGS effects and fluid loss simulation**
- **Channels were found in set samples of cement slurries in which gas migration occurred**



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Overbalance Pressure Is Lost Due to the Combined Effects of:

- **Static Gel Strength**
- **Volume Losses**

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Percolation of Gas Leads to Formation of A Gas Channel

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Percolation Starts When Overbalance Pressure Is Lost

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Static Gel Strength is the Internally Developed Rigidity Within the Matrix Which Resists Forces Placed Upon It

Gel Strength Definitions

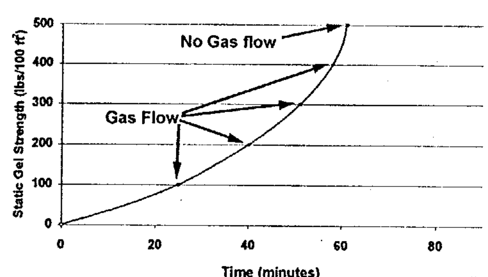
- Gel Strength in units of # / 100 sq. ft.
- ZGT = Zero Gel Time
  = Time to 100 #
- TRT = Transition Time
  = Time from 100# to 500 #

Volume Loss Occurs Due To:

- Filtrate Loss
- Cement Hydration Reaction

Once Gas Enters the Well Bore, the Volume Losses Elsewhere in the Well Correspond to How Much Gas Will Enter and Ultimately the Size of the Gas Channel Formed

Maximum SGS for Gas Flow



Actual Pressure Loss Is Not Caused by Static Gel Strength Alone. It must be accompanied by Volume Loss.

Actual Pressure Loss Is the Result of the Combined Effects of Volume Loss and Static Gel Strength

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Pressure Decrease
Due To Volume Losses

$$\Delta P = \Delta V / CF$$

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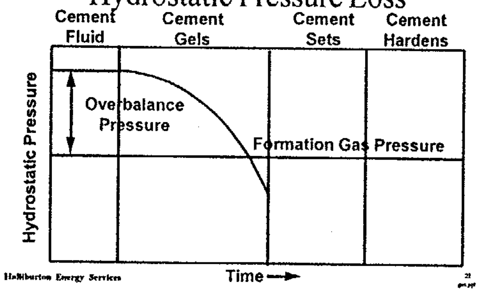
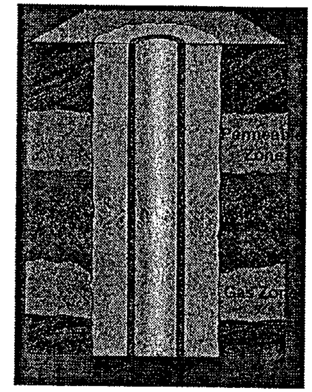
Hydrostatic Pressure Loss





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Gas Channel Formation

- Cement slurry placed
- Slurry behaves as a fluid
- Transmits full hydrostatic pressure

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ΔV Pressure Losses Can be Minimized by Using Fluid Loss Control Additives.

CF Is Very Low for Standard Cements, But Can Be Altered Significantly

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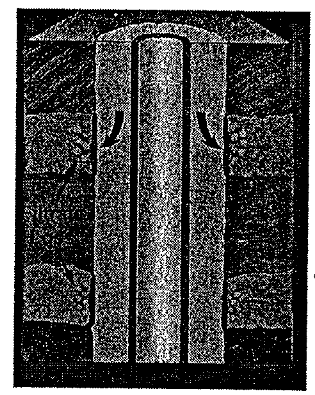
Therefore, Any Method for Solving Gas Migration Must Deal With:

- **Fluid Loss**
- **Static Gel Strength**
- **Compressibility**
- **Combination of the Above**



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Gas Channel Formation

- Static gel strength development begins
- Fluid loss to formations
- Volume reduction causes pressure loss

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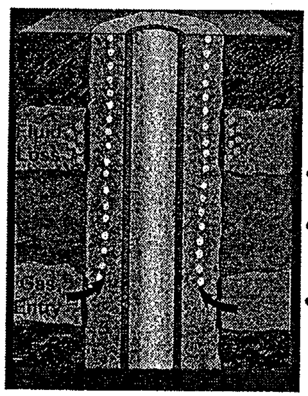
Gas Channel Formation



- Overbalance Pressure is lost
- Fluid loss continues in lower pressure zone
- Gas enters wellbore and percolates up annulus

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How Do We Determine The Severity of Gas Flow Problems?

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Using Individual Well Conditions, We Calculate a Flow Potential Which Represents the Probability for Gas Migration to Occur and It's Severity.

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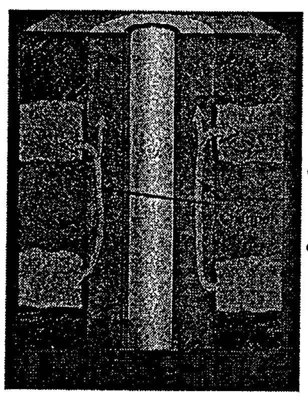
Gas Channel Formation



- Percolation leads to gas channel formation
- Permanent channel left after cement sets

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Halliburton's Gas Flow Prevention Plan

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Maximum Hydrostatic Pressure Restriction Due to Static Gel Strength

$$MPR = \frac{SGS}{300} \times \frac{L}{D}$$

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Because Gas Percolation Cannot Be Initiated Through Cement With SGS $\geq$ 500 LB/100 Ft.$_2$

And: $MPR = \frac{SGS}{300} \times \frac{L}{D}$

Then: $MPR = \frac{500}{300} \times \frac{L}{D}$

$\frac{500}{300} = 1.67$

Therefore: $MPR = 1.67 \times \frac{L}{D}$

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1	2	3	4	5	6	7	8	9	10	

GAS FLOW POTENTIAL FACTOR

Flow Condition 1 Minor | Flow Condition 2 Moderate | Flow Condition 3 Severe

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1	2	3	4

Flow Condition 1
Minor

- Fluid Loss Control
- Modified Job Design

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Gas Flow Potential

$$GFP = \frac{MPR}{OBP}$$

$$MPR = 1.67 \times \frac{L}{D}$$

OBP (Overbalance Pressure) =

Hydrostatic - Gas Reservoir Pressure

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Typical Slurry Requirements For Each Flow Condition

- Minor
- Moderate
- Severe

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Minor GFP Solutions

Fluid Loss Control: Limits Volume Reduction

Modified Job Design: Lowers GFP by use of backpressure, shortened cement column, and other parameters

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5	6	7

Flow Condition 2
Moderate

- GasStop
- Thixotropic Cements

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8	9	10	∞

Flow Condition 3
Severe

- GAS-CHEK Cement
- Super CBL
- Foam Cement

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Types of Gas Migration

- Flow Through Unset Cement
- Flow Caused by Mud Channels
- Flow Through Micro-Channels

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Moderate GFP Solutions

GasStop: Delays Gel Strength with Rapid Transition Time

Thixotropic Cements: Rapid Gel Strength minimizes time for gas to percolate in annulus

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Severe GFP Solutions

GAS-CHEK: Generates gas downhole to make slurry compressible

Super CBL: Generates gas downhole to make slurry compressible

Foam Cement: Compressible cement slurry

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Flow Through Mud Channels And Micro-Channels

- **Mechanism**
- **Characteristics**
- **Solutions**

Theory of Gas Flow (Mud Channel, Micro-Channel)

- Gas migration through micro-channel due to differential pressure (flow volume is small)
- Gas Flow continues, mud channels and cement undergo shrinkage

Gas Migration In Mud Channels Characteristics

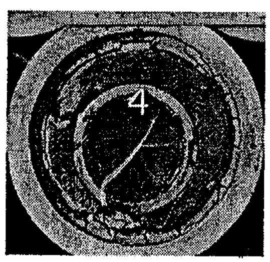
- Flow Observed "Days" After Cement Is Placed.
- Flow Volume Is Slight To Moderate
- Gas Flow Increases With Time.
- Can Be Altered By Good Displacement Practices

Gas Migration In Mud Channels Solutions

- Apply Good Displacement Practices
- Expansive Cement Additives
- Compressible Cements

Gas Migration Mud Channels Mechanism

- Cement sets with no gas flow
- Plastic state shrinkage occurs
- Gas flows through micro channel
- Channel widens due to shrinkage



Gas Migration In Mud Channels Characteristics

- Cement Slurry Composition Can Alter Flow
- Job Techniques Can Alter Flow
- May or May not Require Remedial Job
- Flow May or May not be Observed With CBL, PET, or CAST-V logs

Microannular Flow

- Causes
- Prevention
- Solutions

Microannular Flow

Causes

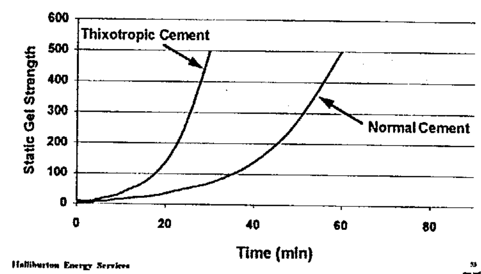
- Cement Sheath Damage
- Combination of Mud Channel and Sheath Damage
- Poor Cement Bond

Mud Channels And Micro-Channels

Remediation

- Very Difficult - Sometimes Not Possible
- Use Of Micro Fine Cement (Micro Matrix)
- Use Of Resins (Epseal)
- Use of Monomer Solutions (Perm Seal)

Thixotropic Cement



Microannular Flow

Prevention

- Good Displacement Practices
- Do Not Pressure Test Prematurely
- Pressure Test before Cement Sets
- Do Not Drill Out Prematurely
- Use Ductile or Flexible Cements

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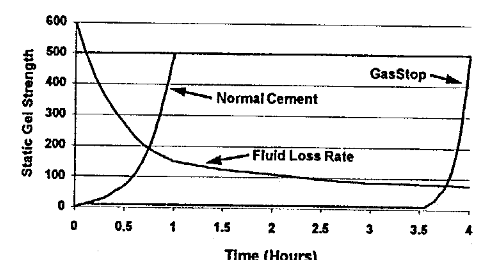
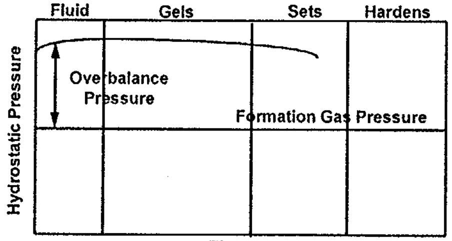
THANKS YOU
FOR YOUR TIME

Delayed Gel Strength and Fluid Loss



Cement w/ GAS-CHEK



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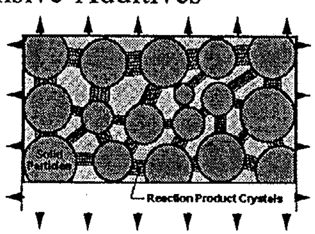
Expansive Additives

- **Microbond**
  - Below 130 °F
- **Microbond M**
  - 130 to 210 °F
- **Microbond HT**
  - Above 210 °F



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APPLICATIONS OF BLAST FURNACE SLAGS IN PREVENTING FLUID MIGRATION BEHIND CASING

by Fred Sabins and Timothy Edwards
Westport Technology

EXCERPT FROM: DEA-87 PERFORMANCE STUDIES OF MUD CONVERTED TO CEMENT

APPLICATIONS OF BLAST FURNACE SLAGS IN PREVENTING FLUID MIGRATION BEHIND CASING

DEA-87 PHASE I

- Objective:
Compare the effectiveness of converting drilling fluids with Blast Furnace Slag (BFS) for use in cementing applications with Portland Cement

- Application Focus:

Primary Cementing Operations
  General Cementing Conditions
  Critical Cementing Conditions

MUD TO CEMENT CONVERSION

- MTC TECHNOLOGY

Standard Drilling Fluid

+ Blast Furnace Slag

+ Activators

= Material with Cementitious Properties

WHY MTC TECHNOLOGY?

- Lower Cost Materials
  - Base Materials Used
  - Additives Used
  - Spacer Fluid

- Technical Advantages
  - Compatibility with Drilling Fluids
  - Good Properties

- Combine Mud and Cementing Operations

- Disposal of Mud/Environmental Impact

Concerns of Zone Isolation

- Cost of Cementing Wells
  - 5% of Well Cost (Normal)
  - Up to 20% of Well Cost (Problems)
  - Survey - 15% Failure

- Problems still exists with Cementing
  - Gas Migration
  - Water Flow
  - Lost Circulation
  - Squeeze of Primary Jobs

WHY DEA-87?

- Developing Technology

- Technical Concerns Raised by Industry
  - Fluid Migration
  - Corrosion
  - Dimensional Stability
  - Brittle Properties
  - Seal of Annulus

DEA-87 PARTICIPANTS

- Amoco, Baker Hughes Inteq, Baroid, Blue Circle Cement, BP, Chevron, Conoco, CTC, DS, HES, Koch Minerals, MI, Mobil, Maersk, Nowsco, Shell, Texaco

SUMMARY OF DEA-87 PHASE I

- GAS MIGRATION
- THERMAL & CHEMICAL STABILITY
- DIMENSIONAL STABILITY
- MECHANICAL PROPERTIES

RESULTS OF PHASE I

- RELIABLE GAS MIGRATION MODEL

- GAS MIGRATION FOR BFS-SYSTEMS IS SIMILAR BUT DIFFERENT THAN PORTLAND

  - SIMILIAR IN PRESSURE DROP
  - DIFFERENT IN SEAL TO GAS AFTER SET

GAS MIGRATION COMPARISON

- HYDRATION VOLUME REDUCTION (5%) - 250 cc's

  - PORTLAND (344) - 70 cc's

  - PORTLAND (D160) - 20 cc's

  - BFS/DISPERSED MUD - 475 cc'

  - BFS/PHPA MUD - 1800 cc's

PERMEABILITY TO GAS

SYSTEM	BULK PERM	CORE PERM
BFS/DISP	6 md	5 x 10E-5 md
BFS/PHPA	15 md	5 x 10E-5 md

CONCLUSIONS FROM PHASE I

- APPLICATIONS FOR GENERAL OR NON-CRITICAL CEMENTING
- QUESTIONS CONCERNING CRITICAL CEMENTING APPLICATIONS
  - GAS MIGRATION

QUESTIONS ?

- LONG TERM ANNULAR SEAL?
- MECHANISM OF GAS FLOW?
- DIFFERENT COMPOSITIONS?
- HYDRATION MECHANICS/ CRACKING?

DEA-87 PHASE II

- FOCUSED ON SIMULATING PERFORMANCE PROPERTIES OF BFS/MUD COMPARED WITH PORTLAND CEMENT

  GAS MIGRATION AND LONG TERM LEAKAGE

  ANNULAR SEALING

  LITERATURE SEARCH ON SLAG HYDRATION

EXPECTATIONS FROM PHASE II

- QUANTIFY ABILITY OF BFS/MUD TO CONTROL
  - SHORT TERM GASMIGRATION
  - LONG TERM LEAKAGE

- MECHANISM OF GAS FLOW / BFS SYSTEMS

- ABILITY TO SEAL / ANNULAR CONFIGURATION

SUMMARY OF PHASE II PHPA MUD

- GAS MIGRATION
  - 4/0 = PORTLAND CEMENT
  - 4/0 > 4/4 > 4/8 > 4/12

- ANNULAR SEALING
  - 4/0 = PORTLAND CEMENT
  - 4/12 << PORTLAND CEMENT

EXPECTATIONS FROM PHASE II

- QUANTIFY ABILITY OF BFS/MUD TO CONTROL
  - SHORT TERM GASMIGRATION
  - LONG TERM LEAKAGE
- MECHANISM OF GAS FLOW / BFS SYSTEMS
- ABILITY TO SEAL / ANNULAR CONFIGURATION

SUMMARY OF PHASE II PHPA MUD

- GAS MIGRATION
  - 4/0 = PORTLAND CEMENT
  - 4/0 > 4/4 > 4/8 > 4/12
- ANNULAR SEALING
  - 4/0 = PORTLAND CEMENT
  - 4/12 << PORTLAND CEMENT

SUMMARY OF PHASE II DISPERSED MUD

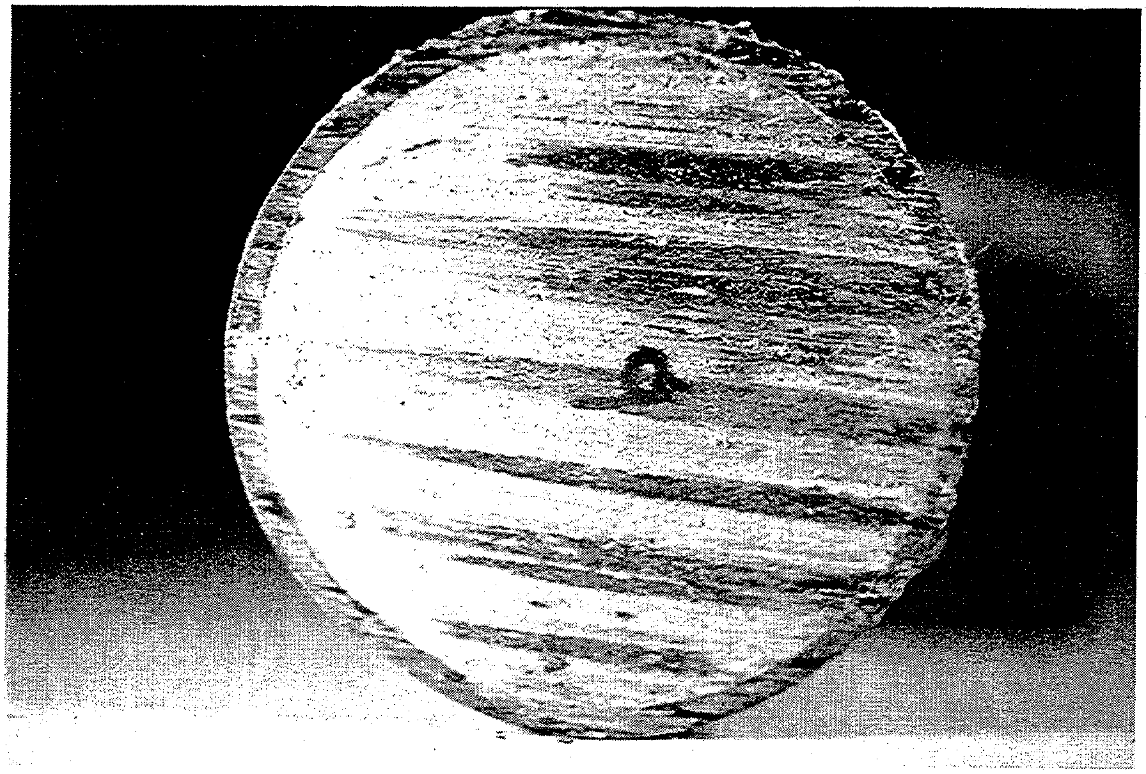
- GAS MIGRATION
  - 4/0, 4/4, 4/8 = PORTLAND
  - 4/12 << PORTLAND
- ANNULAR SEAL
  - ALL BFS << PORTLAND

PHASE II FUTURE WORK

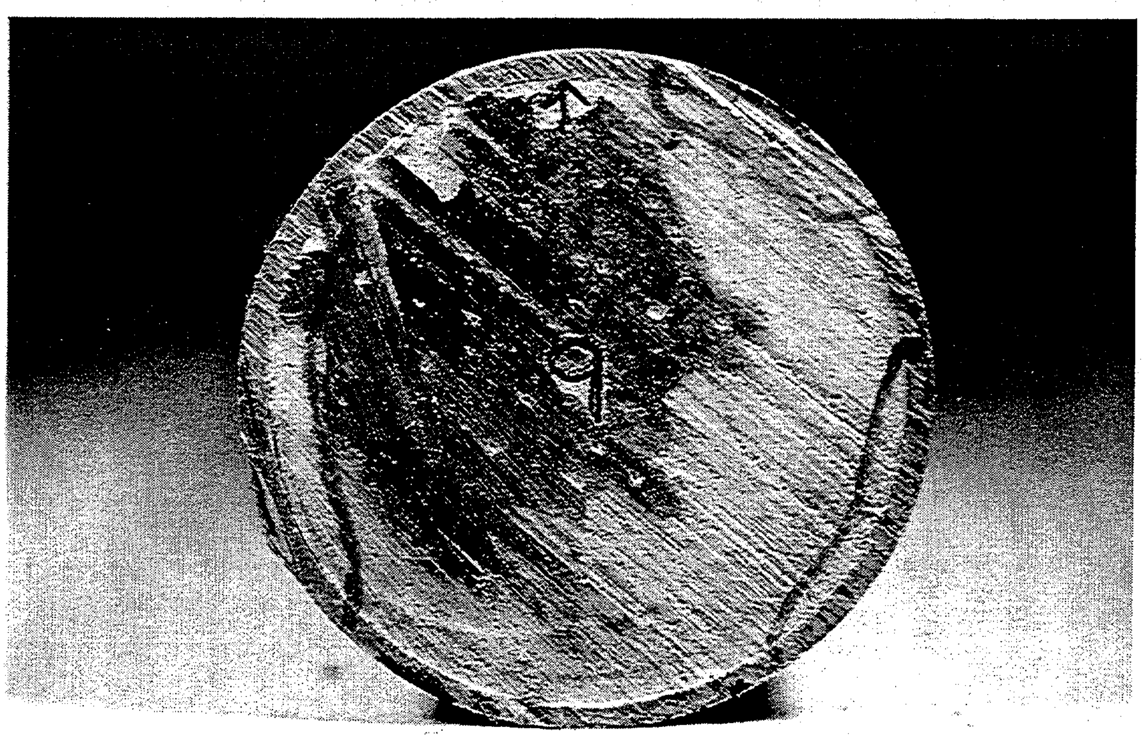
- LOWER DENSITY BFS SYSTEMS
  - REDUCED BFS
- ALTERNATE ACTIVATORS
- STATIC GEL STRENGTH

CONCLUSIONS

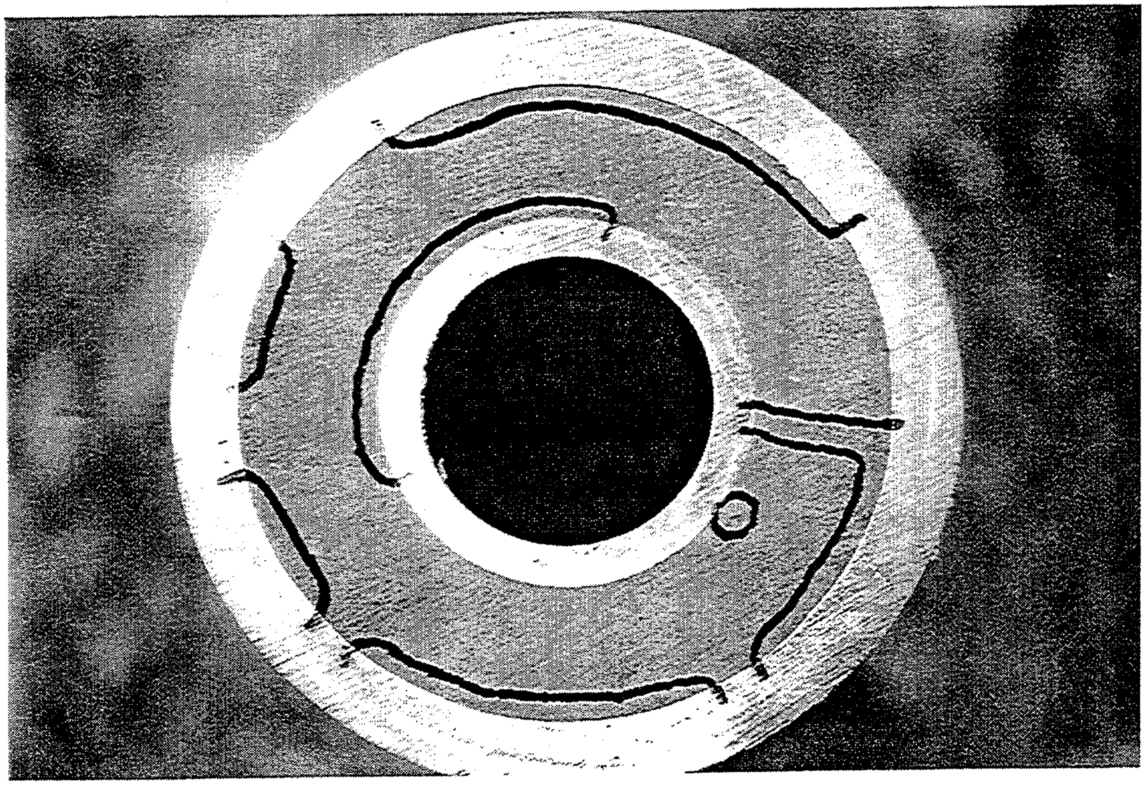
- COMPARISON OF BFS SYSTEMS & PORTLAND CEMENT
  - OPTIMIZED BFS CAN BE AS EFFECTIVE AS PORTLAND CEMENT
- TECHNOLOGY IS EVOLVING IN SYSTEM DESIGNS & APPLICATION



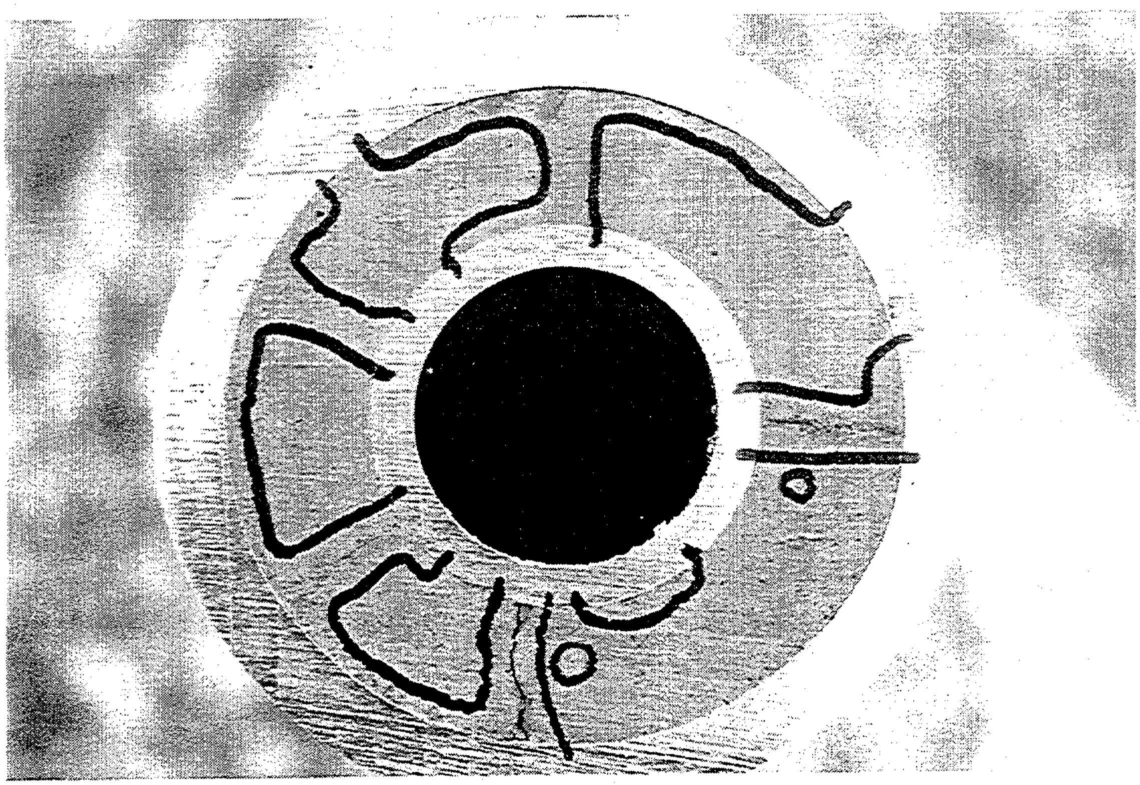
Gas Migration - Portland Cement



Gas Migration - BFS



Annular Seal - Portland Cement



Annular Seal - BFS

CEMENT SLURRY VIBRATION – A METHOD FOR PREVENTION OF FLOW BEHIND CASING: PART 1

CEMENT SLURRY VIBRATION

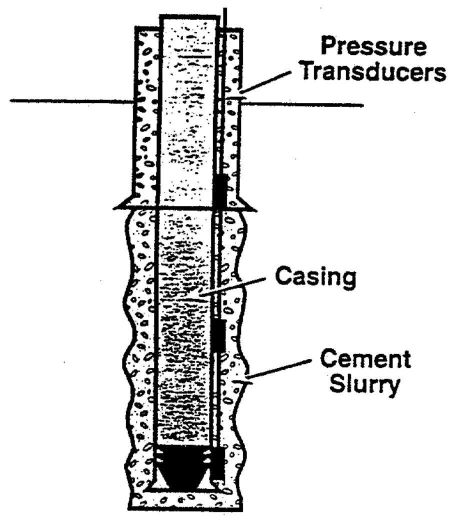
A Method for Prevention of Flow Behind Casing

LSU/MMS WELL CONTROL FORUM

Baton Rouge, Louisiana
November 19 – 20, 1996

John Haberman, Texaco EPTD

TECHNICAL BASIS FOR THIS WORK
Exxon, 1983



EFFECT OF APPLYING PRESSURE TO THE ANNULUS

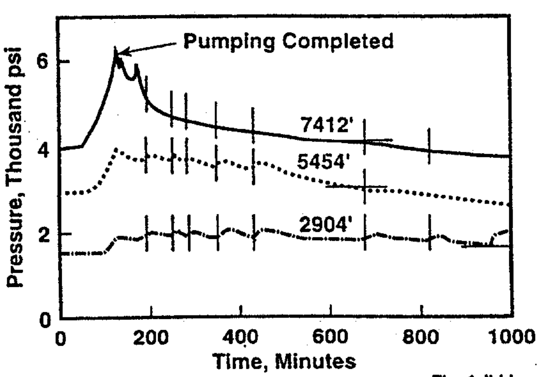


Fig. 4, Ibid

HYDROSTATIC PRESSURE DECLINE AFTER CEMENTING

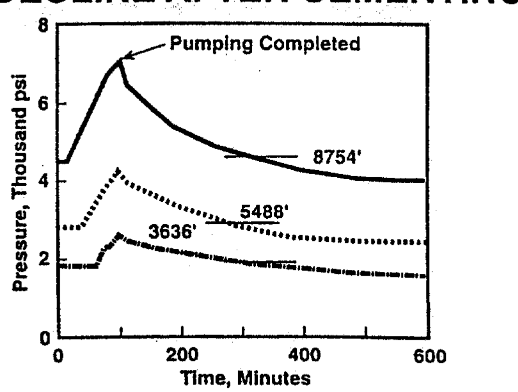
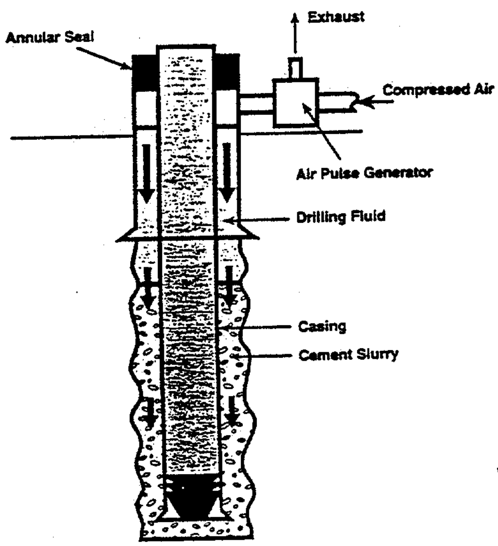


Fig. 2 Cooke, et al, SPE 11206 (1983)

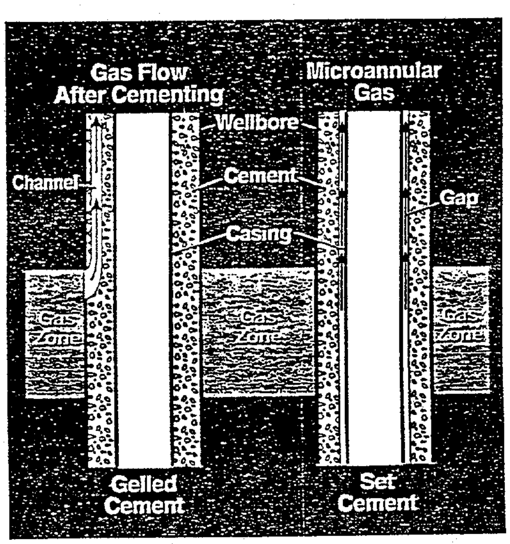
VIBRATING SLURRIES IN WELLS



CURRENT OBJECTIVES

- Bottom Line
  - Improve Bond Logs
  - Prevent Annular Casing Pressure
  - Prevent Gas Migration
  - Remove Mud Channels
- Activities
  - Commercial Prototype
  - Technology Transfer
  - Evaluate Performance

GAS MIGRATION

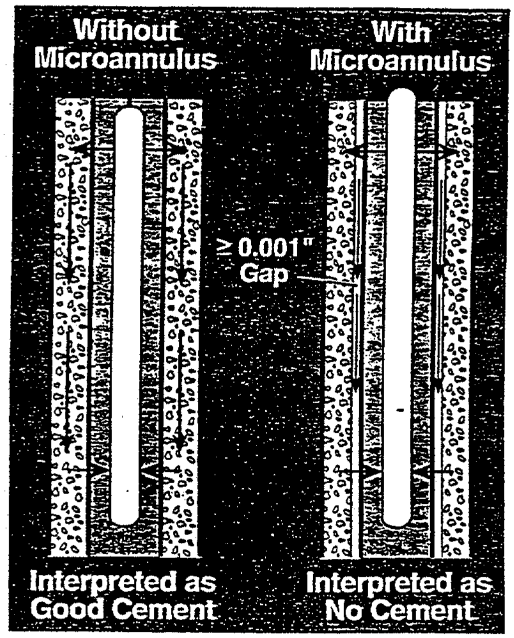


- Cost to Industry $20 – 50 MM/Yr

CURRENT TECHNOLOGY

- Gas Flow After Cementing
  - Fluid Loss Control Additives
  - Matrix Permeability Additives
  - Delayed Gel Strength Additives
  - Gas Generating Additives
  - Diverters
  - External Casing Packers
  - Sandwich Squeeze
  - Casing Rotation
- Microannular Gas
  - Expanding Cements
  - External Casing Packers
  - Rubber Seals
  - Sandblast Casing
  - Surface Rust
  - Special Coatings

ULTRASONIC LOGS



- Pressure Casing
- Unnecessary Remedial Squeeze Operations

TEST OBJECTIVES

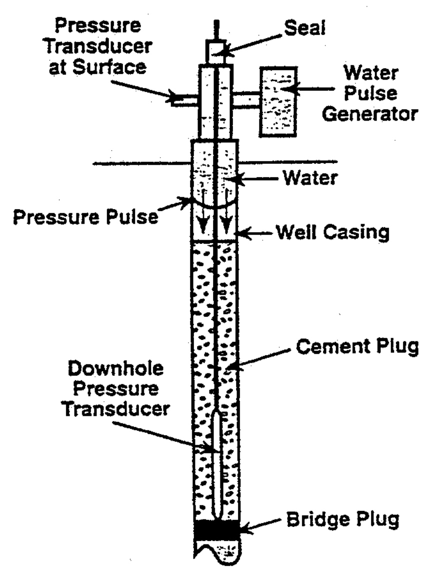
- Measurements In Wells
  - Well Abandonments for Pulse Transmission Measurements
  - New Wells for Fluidity Maintenance
  - New Wells for Ultrasonic Logs
- Laboratory Tests

MECHANISMS OF PULSE TRANSMISSION

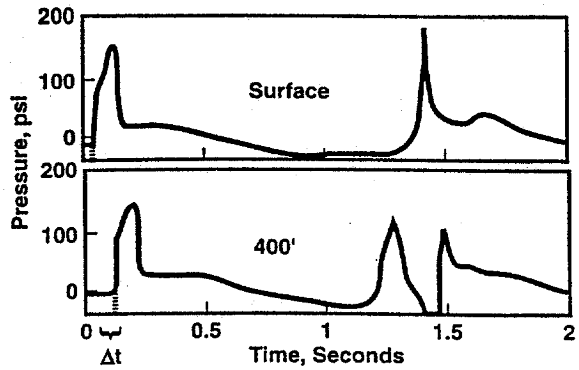
- Pulse Propagation
  - Small Displacement
  - Short Pulse Width
  - Water Pulse Generator
- Fluid Spring
  - Large Displacement
  - Long Pulse Width
  - Air Pulse Generator

PULSE PROPAGATION MECHANISM

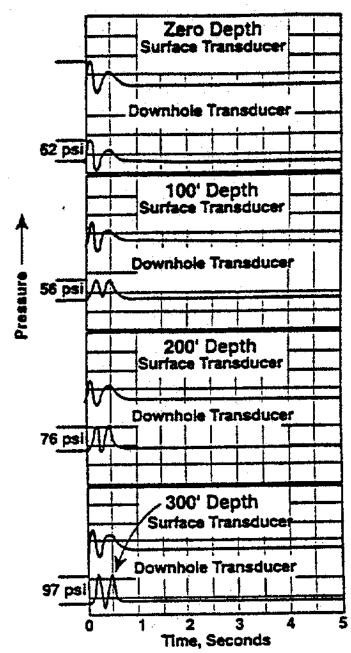
Well Abandonment



WATER-FILLED CASING
Single-Shot With DHPT

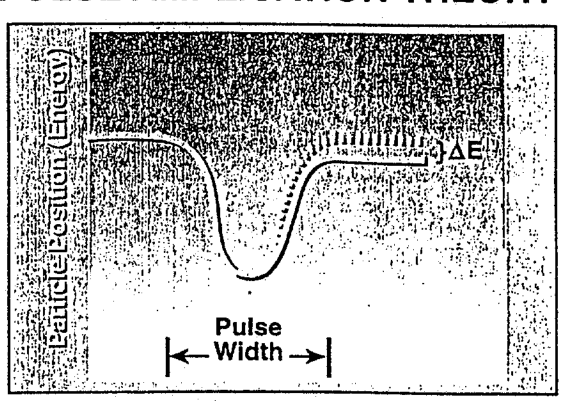


WELL TEST DATA

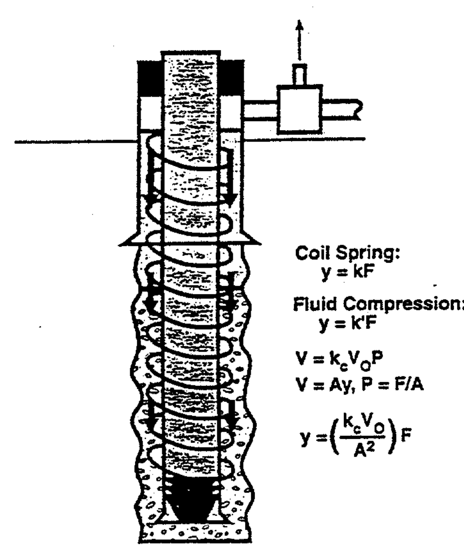


Mabee Field, Midland, Texas

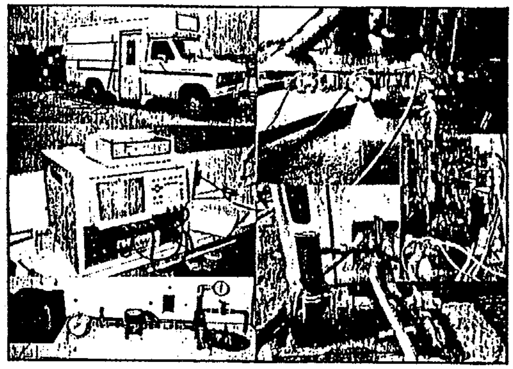
PULSE AMPLICATION THEORY



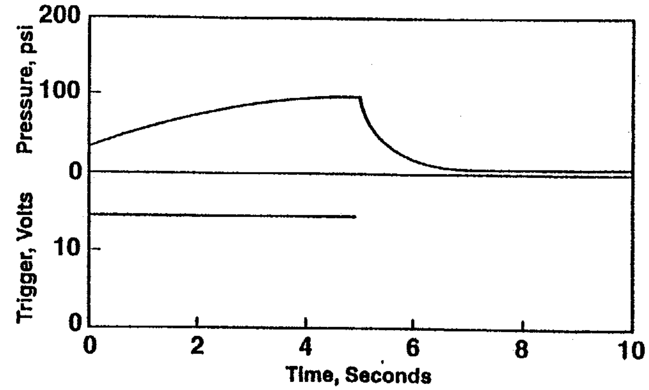
FLUID SPRING MECHANISM



AIR PULSE GENERATOR AND COMPRESSIBILITY TEST

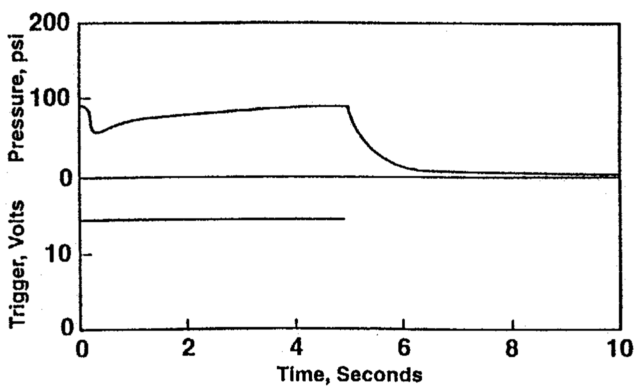


AIR PRESSURE IN ANNULUS



AIR PRESSURE IN ANNULUS

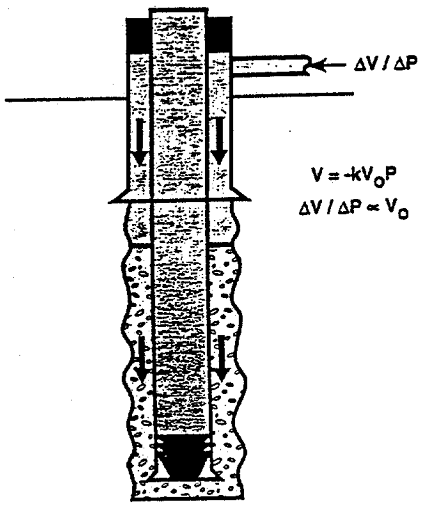
40 Gallon Air Storage Tank



WELLS

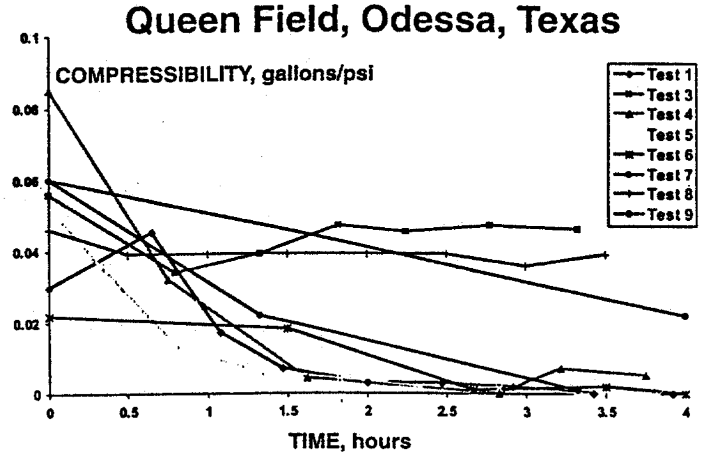
- North Concho (Queen) Field, Odessa, Texas
- 8 5/8" surface casing to about 1500'
- 7 7/8" bit with 10 ppg brine to TD
- 5 1/2" production casing to about 4700'
- Cement circulated to surface
- Lead 12.8 ppg 50/50 Poz/H 2% bentonite
- Tail 14.2 ppg 35/65 Poz/H 6% bentonite
- Normally no FL control
- Low FL slurry D112<50 cc in lead and tail

MONITORING FLUIDITY

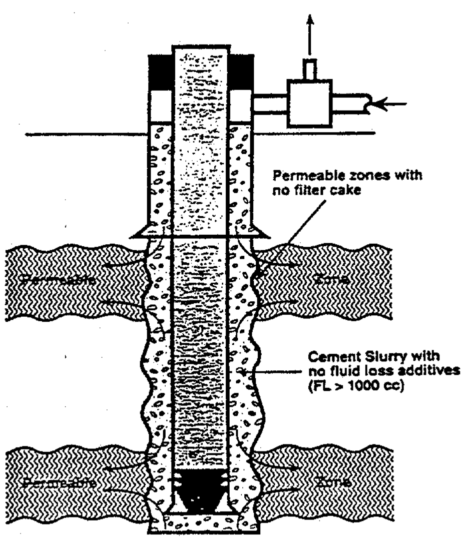


Measure Compressibility of Slurry

Slurry Compressibility
Queen Field, Odessa, Texas



DEHYDRATION OF CEMENT SLURRY



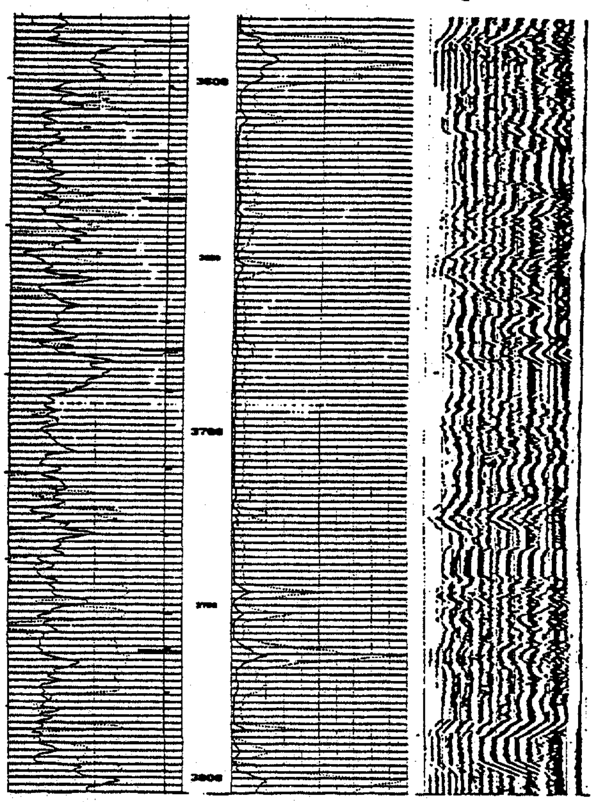
WELL TEST RESULTS

Compressibility Decline
Queen Field, Odessa, Texas

Test	Conditions	Slope (ΔC/hr)	Intercept (hr)
1	WPG	0.069	1.8
2	Control	N/A	N/A
3	WPG	Negligible	∞
4	APG, 185 cfm	0.072	2.4
5	APG, 375 cfm	0.049	1.4
6	APG, 375 cfm, tank	0.015	3.2
7	Control	0.019	3.2
8	APG, 185 cfm, continuous	Negligible	∞
9	APG, 185 cfm, FL	0.010	7.2

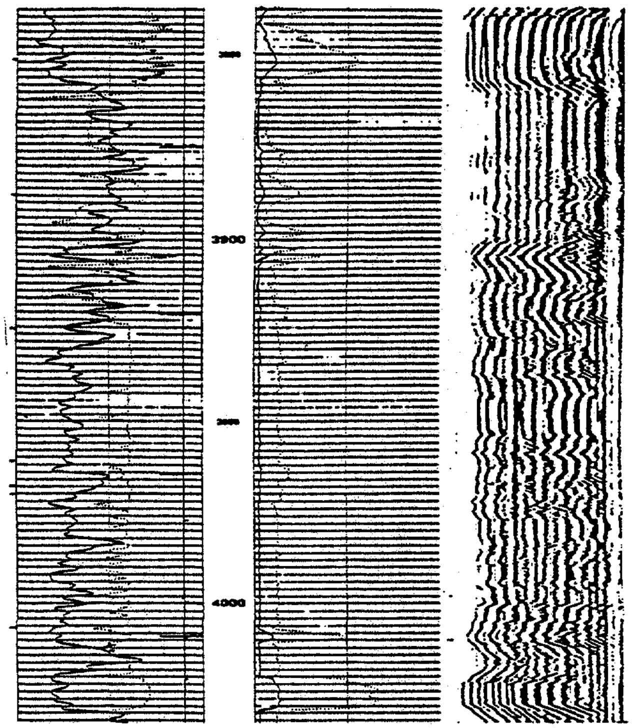
TEST 1

48 Hrs. Cement Bond Log



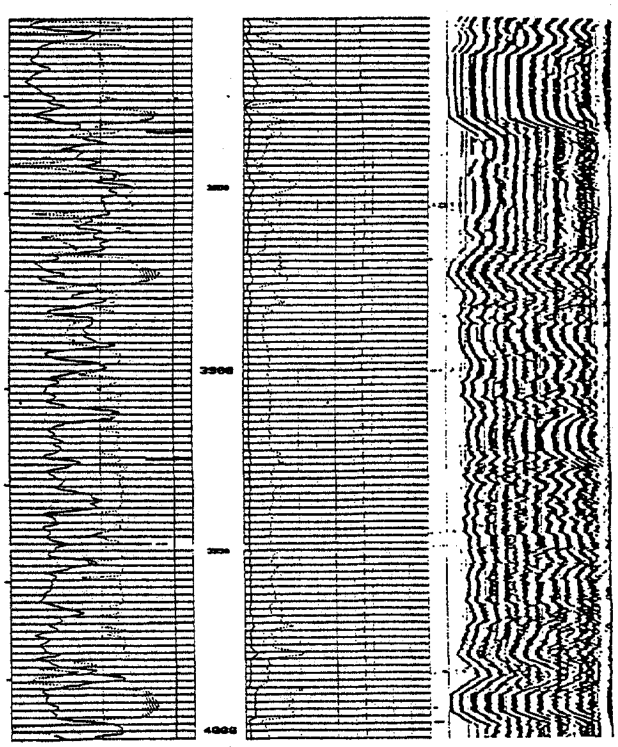
TEST 2

48 Hrs. Cement Bond Log



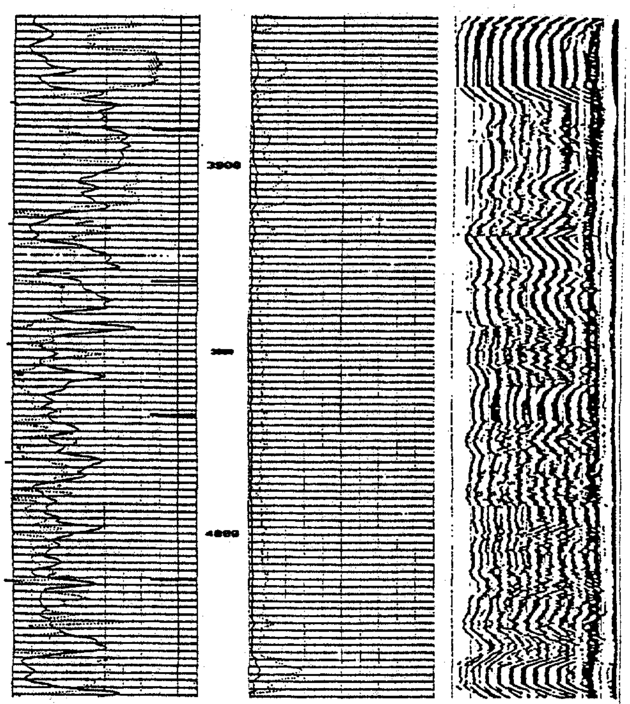
TEST 3

60 Hrs. Cement Bond Log



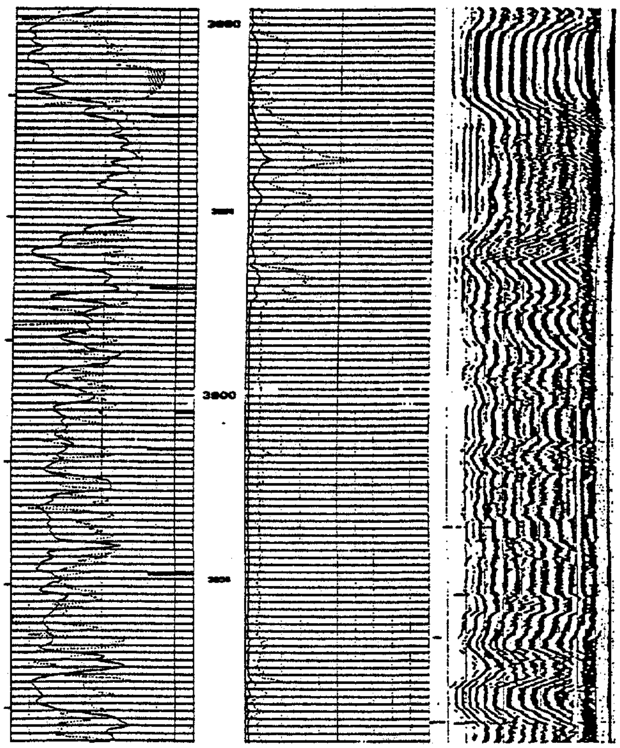
TEST 4

48 Hrs. Cement Bond Log



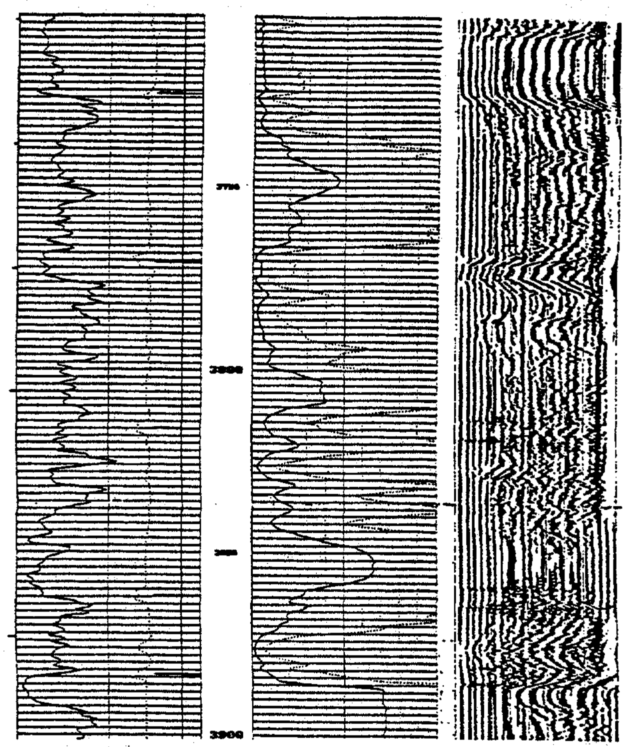
TEST 5

48 Hrs. Cement Bond Log



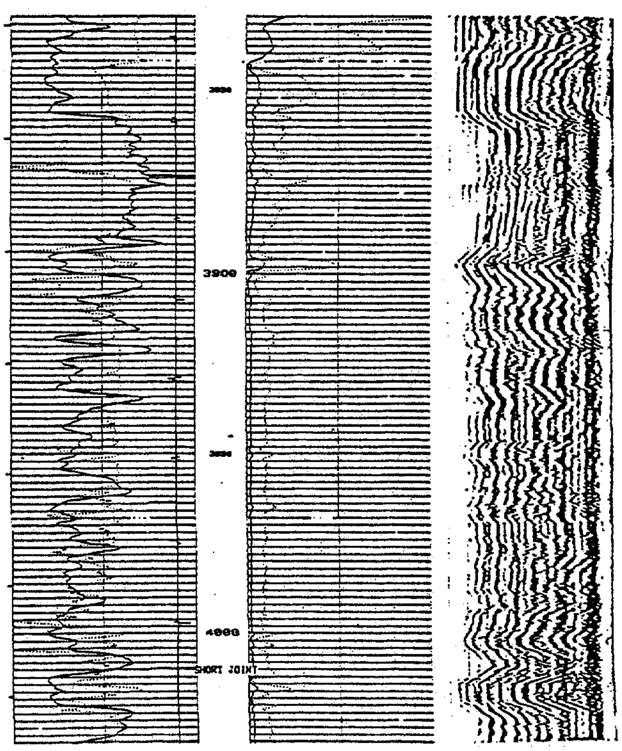
TEST 6

48 Hrs. Cement Bond Log



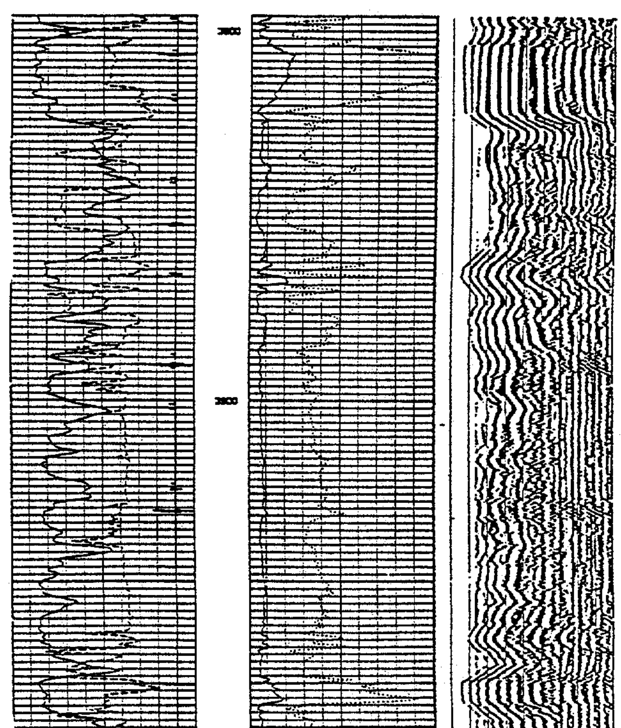
TEST 7

60 Hrs. Cement Bond Log



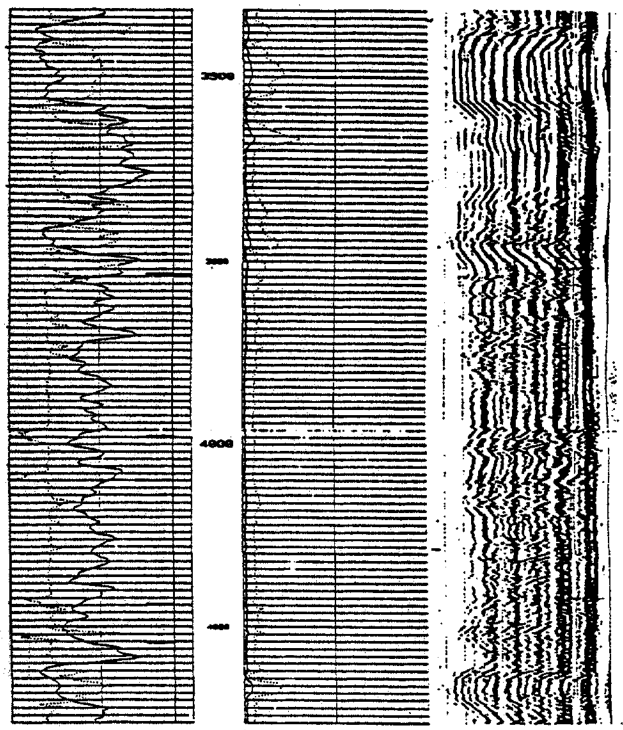
TEST 8

48 Hrs. Cement Bond Log



TEST 9

72 Hrs. Cement Bond Log



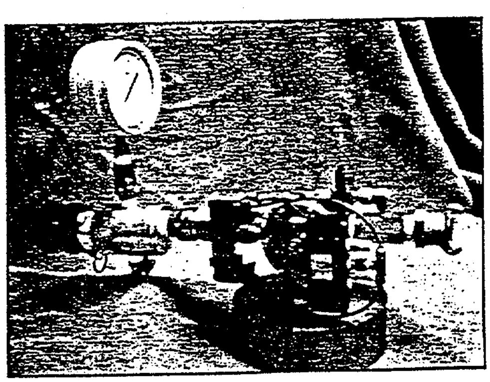
WELL TEST RESULTS

Bond Logs
Queen Field, Odessa, Texas

Test	Conditions	Amplitude (mv)	Transit Time (µsec)
1	WPG	1.5	>279
2	Control	2.5	223
3	WPG	3.0	225
4	APG, 185 cfm	1.5	>281
5	APG, 375 cfm	1.5 -	221–251
6	APG, 375 cfm, tank	20*	214
7	Control	2.0	226
8	APG, 185 cfm, continuous	7.0	273
9	APG, 185 cfm, FL	1.0	259

* Casing pressure tested to 1000 psi before CBL.

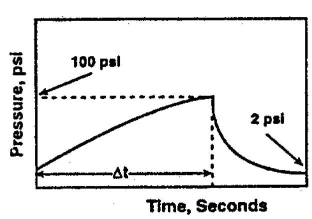
COMMERCIAL PROTOTYPE

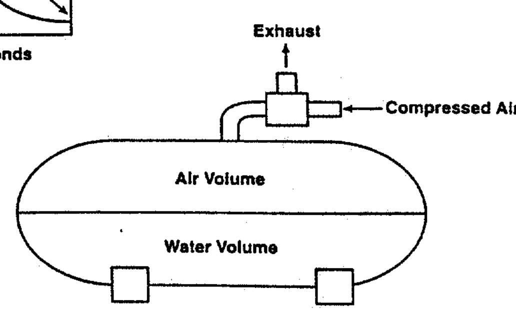


- High Speed Air Valve
- Pressure Activated Cycle

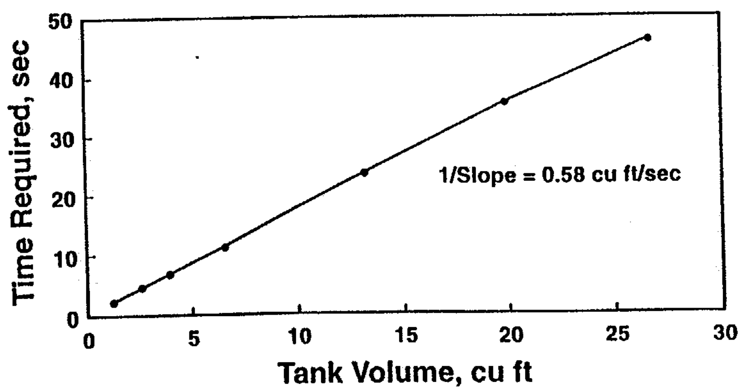
MONITORING THE STROKE

Calibration of a 185 cfm Compressor

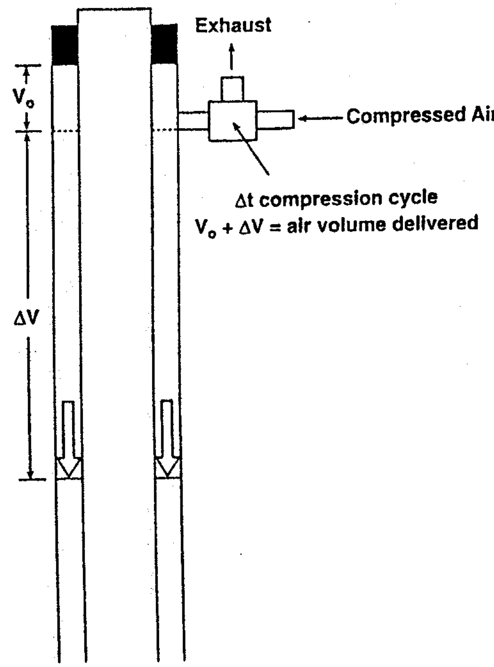




CALIBRATION OF A 185 CFM COMPRESSOR
Time Required to Increase Pressure to 100 psi



MONITORING THE STROKE



OBSERVATIONS

- Fluidity maintained, CBL not as good
- Fluidity declined, CBL improved
- Continuous vibration to maintain fluidity
- Slurry dehydration effects
- No well problems
- Practical to do

FUTURE PLANS

- Test on a variety of wells
- Commercial prototype air pulse generator
- Water injection/discharge by cement pump
- Yard scale tests
- Hydrostatic pressure measurements in wells

SEALING GAS ZONES BY VIBRATING CEMENT SLURRIES

by

John P. Haberman

Texaco E & P Technology

Sealing Gas Zones by Vibrating Cement Slurries

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Texaco E&P Technology

A relatively simple, inexpensive device has been developed to vibrate cement slurry deep in wells to improve cement bonding and prevent gas migration. Gas Research Institute (GRI) is supporting parallel activities to improve this new technology and lay the groundwork for commercialization and technology transfer.

As the cement surrounding a well's casing hardens, it undergoes physical changes that can lead to gas migration and a lack of competency in the hydraulic seal between the casing and the formation. One way to lessen this problem is to create movement among the cement particles during the curing process.

Since the casing is mechanically connected to the surface equipment during cementing, vibration of the casing in contact with well cement slurries has been the obvious choice for study in the laboratory (Chow *et al.*, 1988; and Skalle *et al.*, 1992) and by full-scale yard testing (Cooke *et al.*, 1988). Large-scale hydraulic equipment has been constructed to support and vibrate the casing string directly (Bodine *et al.*, 1987). It has also been proposed to vibrate the casing by lowering various energy sources down inside the casing (Cooke 1983; Solum *et al.*, 1971; Walter, 1991; and Winbow, 1994). However, none of these approaches has resulted in a practical device for well cementing.

An alternative strategy does not involve vibrating the casing; it would vibrate the slurry directly by sending pressure pulses down the annulus. This approach uses very simple and inexpensive equipment to introduce pulses of water or compressed air directly into the annulus, at the surface, above the slurry (Haberman *et al.*, 1995). The annulus serves as a wave guide to transmit the pressure pulses deep into the well through the slurry.

GRI and *Texaco Exploration and Production Technology Company* have collaborated in the development of a process that is very simple and inexpensive to apply. It has not caused any operational problems where it has been applied, and cement bond logs have incrementally improved. The technology is ready to be tested on deeper, more complex wells.

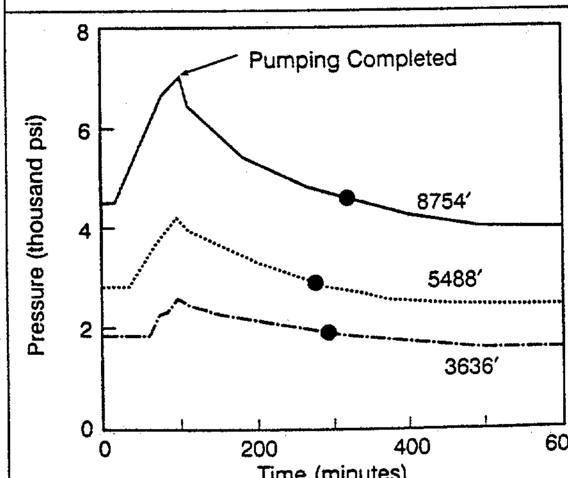
Pressure Loss Affects Cement

When a gas well has been drilled and cased, a liquid cement slurry is pumped down into the casing and displaced up into the annular space between the casing and the wellbore wall. Within a few hours the slurry solidifies to provide a permanent seal. During the transition from a static liquid slurry to a solid, the cement slurry becomes a gel. When this occurs the volume of cement decreases slightly. This combination of gelation and shrinkage causes a decline in the hydrostatic pressure exerted by the column of cement. This in turn can allow the influx of gas from permeable formations into the unset cement, a condition called gas migration. It can also inhibit the bonding of the cement to the casing. Either of these situations can result in communication between formations via the annulus, and can increase the potential for casing leaks.

Pressurizing Annulus Can Help Lessen Pressure Decline

Researchers have measured this decrease in annular hydrostatic pressure by attaching pressure transducers to the outside of the casing (Cooke *et al.*, 1983). The pressures

Figure 1: Hydrostatic Pressure Decline After Cementing (Cooke et al., 1983)

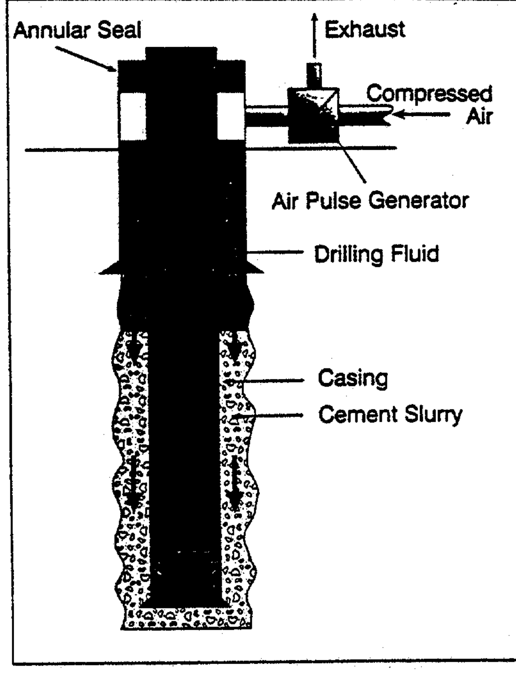


recorded over time at three different depths define the annular pressure regime before and after pumping takes place (Figure 1). The dots indicate the point at which the post-pumping hydrostatic pressure has declined to match the formation pore pressure at each depth. Pressure decline beyond these points illustrates the effect described earlier.

During one such test, water was injected into the annulus at the surface, at a pressure of 60 to 100 pounds per square inch (psi). At shallower depths, this action restored the hydrostatic pressure each time it was performed (Figure 2). At greater depths, the effect was not as obvious, but the time required for the hydrostatic pressure to decline to the pore pressure was about twice that without the pressure applied. This test demonstrated that relatively low pressures applied to the annulus at the surface could restore hydrostatic pressure at substantial depths.

After this approach was demonstrated, operators tried continuously injecting water into the annulus at a low rate to maintain a constant pressure for several hours after cementing (Cooke, 1996). There is no evidence, however, that this practice improved cementing operations. Maintaining a constant pressure would not be expected to have any long-term effect on the gelation of the cement slurry. Hydrostatic pressure could be maintained only by periodically applying pressure to continually agitate the cement particles, preventing the short-range particle interactions that cause gelation.

Figure 3: Schematic of Equipment for Vibrating Cement Slurries in Wells

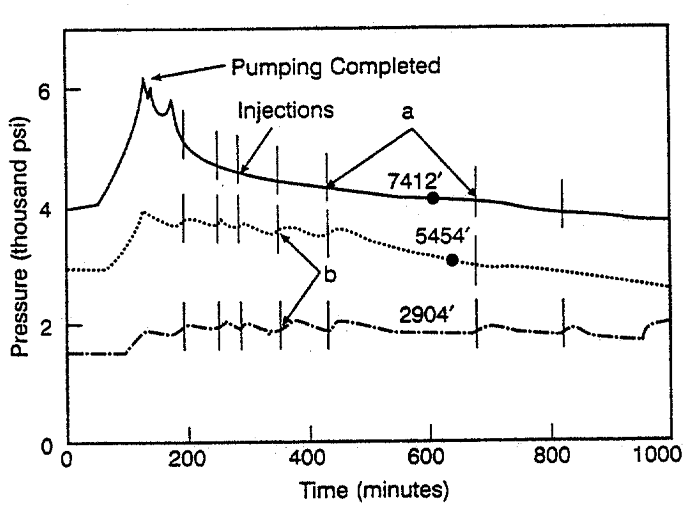


Transmission of Pressure Pulses Through Slurry

An alternative to casing vibration that would achieve this particle agitation would be the direct vibration of the cement. To investigate this alternative a test was designed to show that pressure pulses could be efficiently transmitted through cement slurries. A 300 foot-long column of cement slurry was employed in a well set for plugging and abandonment in the Mabee Field of the Permian Basin in West Texas.

A bridge plug was set at a depth of 300 feet inside $4^1/2$ inch diameter casing and a cement slurry was circulated to the surface. Pressure pulses were applied to the cement slurry at the surface via a water pulse generator and monitored at different depths by a pressure transducer lowered down through the slurry. The amplitude of the single-shot pressure pulses actually increased with depth. The pressure pulses momentarily restored the hydrostatic pressure as they traveled down the cement column, and the net result was to enhance rather than attenuate the amplitude. This result suggested that such a technique could be used to vibrate cement slurries deep within wells, providing an easy and cost-effective method for improving the quality of cement jobs.

Figure 2: Effect of Applying Pressure to the Annulus



a - less effect from pressurizing annulus
b - hydrostatic pressure restored by pressurizing

Vibration Tested in Seven Wells

A set of tests was designed to examine the ability of such a cement vibration technique to improve cementing jobs. Evaluation with cement bond logs (CBLs) and monitoring of the compressibility of the cement slurry were carried out to demonstrate that gas migration could be prevented.

Tests were performed on seven relatively shallow oil wells drilled in the bottom. When the cement developed compressive strength of the same order of magnitude as the applied pressure, the vibration automatically decoupled. This generally began at greater depths (higher temperatures) and advanced upwards toward shallower depths. Vibration continued above this zone where the cement slurry was still fluid.

CBLs Show Best Bond with Air Pulse Vibration

There was concern that vibrating the slurry might unexpectedly deteriorate rather than improve the quality of the cement bond. These wells were expected to have particularly good cement bonds since the drilling brine was easily and completely displaced by the cement slurry.

The CBL amplitudes from four well tests illustrate the effect of vibration on cement bond quality (Figure 4). The amplitudes for identical intervals are overlaid for tests where: an air pulse generator was used to vibrate the cement; a water pulse generator was used; the cement was not vibrated and no compressibility tests were run (Control 1); the cement was not vibrated, but compressibility tests were run at 2-hour intervals (Control 2).

Experts examined the complete CBLs and picked those indicative of the best cement jobs. They consistently chose the CBLs from wells vibrated with the air pulse generator. There was general agreement that while this work did not prove that vibration improved the bonds (all of the CBLs, including the controls, were good), the vibration was not detrimental to the quality of the cement job, based upon the CBLs.

Compressibility Measurements Evidence of Rapid Dehydration

The major objective of this process was to vibrate the cement slurry to prevent gelation and thereby maintain hydrostatic pressure. Accordingly, the fluidity of the slurry was monitored by periodically measuring the compressibility of the fluid in the annulus of four of the test wells. The compressibility could be determined by measuring the ratio of the volume of water pumped into the annulus to increase the pressure by a given amount, and the pressure increase. This compressibility is proportional to the total volume of fluid in the annulus, including the cement slurry that is in a liquid state at the time the measurement is made. The theoretical compressibility was predicted assuming the annulus was completely rigid and full of water. Actual compressibilities have been found to be 2 to 3 times this value due to the elasticity of the wellbore, making this a conservative assumption (Haberman *et al.*, 1991).

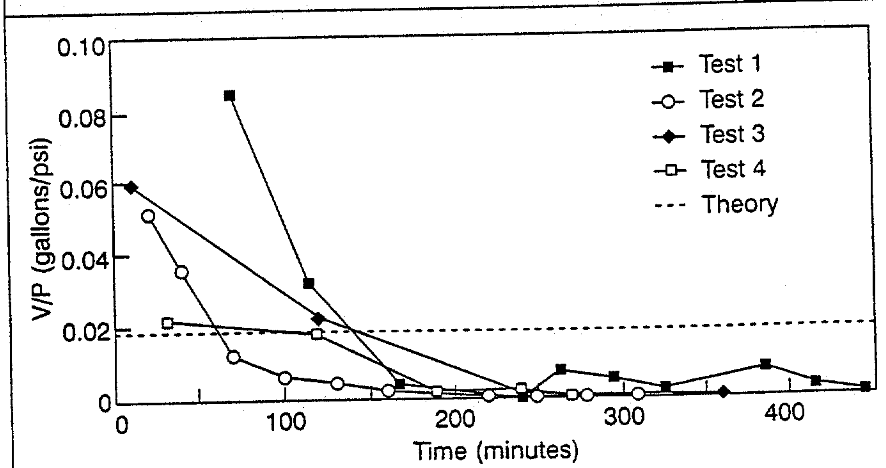
Slurry dehydration, combined with the relatively short thickening time remaining after the slurry was placed, caused a rapid decline in the compressibility of the slurry (Figure 5). This was unexpected. The vibration of the slurry was expected to maintain a high compressibility as the cement solidified. However, the wells were drilled with a no-solids brine that did not provide a filter cake and the cement slurry did not have any fluid loss control additives. After the cement was placed, rapid dehydration of the slurry took place, not as a result but in spite of the vibration. This did not, however, appear to effect the cement bond, as evidenced by the CBLs. Tests currently under way are designed to test the impact of vibration in situations where the dehydration is not so rapid.

Commercialization and Technology Transfer to Follow

Work on commercialization and technology transfer has begun while work on technology refinement is continued. Next steps include:

- Construction and refinement of a commercial prototype
- Presenting results to major service companies and wellsite contractors
- Developing a marketing strategy
- Performing tests on deeper, larger annulus wells
- Performing tests on wells with known gas migration problems
- Development of a technique for monitoring the magnitude of the vertical displacement in the annulus during vibration
- Publication of results.

Figure 5: Compressibility of Slurry in Four Test Wells



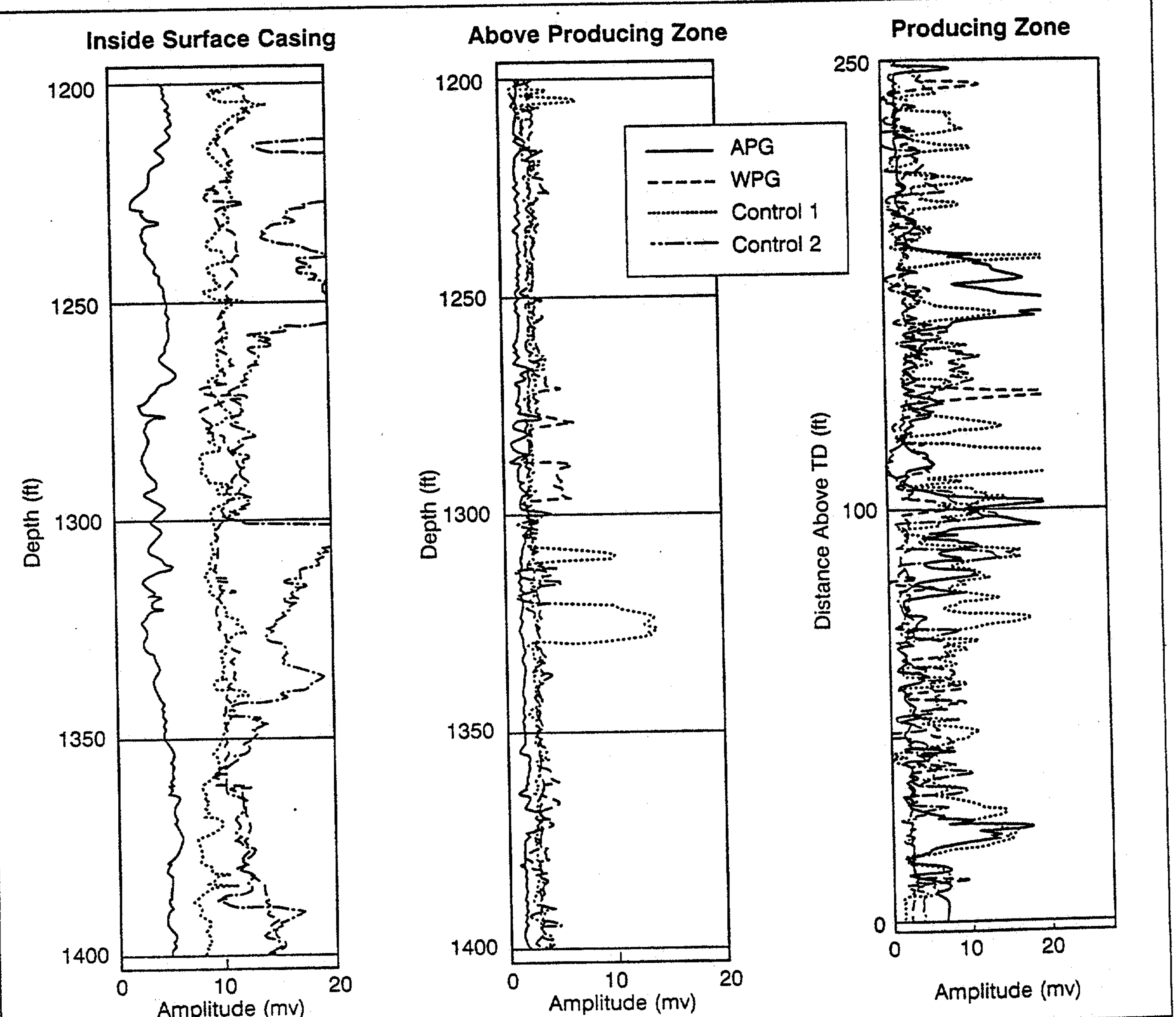
the Concho (Queen) Field of the Permian Basin. These wells were drilled with saturated brine to a depth of approximately 4600 feet. The cement job consisted of a lead slurry with a density of 12.8 pounds per gallon (ppg) followed by a 14.8 ppg tail slurry. The lead slurry was circulated to the surface. These experiments were also used to determine the best way to vibrate cement slurries in the field and to identify any unexpected problems related to the equipment.

Water and Air Pulse Generators Provide Vibration

The first tests were performed with a water pulse generator having a displacement of about 0.5 gallon. This displacement provided a vertical motion of only about 4 inches in the annulus. Most of the testing, however, was done with several configurations of an air pulse generator (Figure 3). This device reciprocated the slurry with an initial vertical motion of about 3 feet at the surface. The pulse width was 5 seconds and the cycle was repeated every 10 seconds (0.1 Hz). Compressed air at a pressure of about 100 psi was provided by trailer-mounted rental air compressors with a delivery of 160 to 375 cubic feet per minute at atmospheric pressure.

When the air pulse generator was used, the fluid in the annulus acted like a fluid spring. The initial vertical displacement of about 3 feet at the surface was inversely proportional to depth, falling off to essentially zero at

Figure 4: Cement Bond Log Amplitude for Three Identical Intervals in Four Wells



The potential for cement vibration to become an accepted and valued technique for improving cement bond quality is excellent. This technique should provide a practical alternative to other, less effective methods for solving a chronic well completion problem. ■

For more information on GRI's research on cement vibration, contact Steve Wolhart, GRI Senior Technology Manager, at 312/399-8278 or John Haberman, Texaco E & P Technology, at (713)954-6235.

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CNG PRODUCING COMPANY

CASE HISTORY

13 3/8 CASING STAIR STEP CASING PRESSURE ELIMINATION PROJECT HIGH ISLAND 571 WELL A-17

Presented By: Ralph Hamrick Slimhole Consulting
Craig Landry CNG Producing Co.

WELL HISTORY

The A -17 was drilled to a depth of 12840' MD and completed in December 1990 in the P-6 sand. Pressure was observed for the first time on the 13-3/8" x 9-5/8 casing annulus on January 2, 1991 at 1645 psi. A departure, requested from 30 CFR 250.87, was granted by the MMS to monitor the unexplained casing Pressure. During 1991 through 1995 The sustained 13-3/8 casing pressure was bled down annually as required by MMS 30 CFR 250.87, each time the 13-3/8" casing pressure was bled down the surface pressure would increase higher than the pre bleed off surface pressure, as seen in exhibit B. The well produced from the P- 6 sand until depletion and a wireline switch was performed to produce the well from the P-3 sand on May 02, 1993. The sustained 13-3/8" casing pressure increased from 1645 psi to 4900 psi over a four year period. February 15, 1995, A study was under taken to determine the cause of the sustained 13-3/8" casing pressure And a course for remedial action. Based on know pressure responses and annulus fluid weights and formation pore pressures, a determination was made that a behind pipe cement micro channel existed at 10500' +- and was allowing a influx to occur through a liner top leak when the 13-3/8 casing was being bleed off. The liner top could not be pumped into using conventional pump in methods.
A detail stair step procedure was prepared and submitted to the MMS for approval and the process was implemented in July 1995. The surface pressure of the 13-3/8" annulus is being controlled and reduced by maintaining a constant bottom hole pressure method to stair-step the influx to the surface and lubricate in 19.2 ppg Zinc Bromide into the annulus using a low volume high pressure pump system. The current 13-3/8" X 9-5/8 casing annulus pressure Is 3000 psi.

- **Since July 1995 the 13-3/8" annulus has been bled from 4500 psi to 3000 psi**
- **118 bbls of 19.2 Zinc Bromide has been pump into the 13-3/8" x 9-5/8" annulus**
- **152 bbls of 7.4 to 9.5 ppg gas cut water/ mud have been bled off the 13-3/8 x 9-5/8 annulus.**
- **Resulting in a net increase of 821 psi in the hydrostatic bottom hole pressure at the liner top.**

WELL INFORMATION

COMPLETION P-3 SAND 12315 - 12450 MD 11967' - 12095 TVD BHP 2746 PSI.

PRODUCTION TBG DETAIL
3-1/2" 12.95 LB/# N-80 PH-6CB 2.750 ID
SURFACE TO 12141'

CAMCO SCSSV	@ 572'	2.562 ID.
R NIPPLE	@ 704'	2.562 ID,
R NIPPLE	@ 12090	2.562 ID,
S-1 NIPPLE	@ 12343'	1.875 ID
PACKER	@ 12128' MD	

8 GAUGE G/P SCREEN 12248'-12346' & 12368'-12407'
PBTD PX PLUG SET IN S-2 NIPPLE 12426'

CASING DETAIL

ANNULUS	WT/GRADE	MAXIMUM INTERNAL YIELD	20% MAXIMUM INTERNAL YIELD	DATE CASING INSTALLED	TOTAL DEPTH
26" DRIVE PIPE	3/4" WALL THICKNESS				590'
20" CONDUCTOR	94"/ K-55	2410 PSI.	482 PSI.	1990	1260'
16" SURFACE	84# /K-55	2980 PSI.	596 PSI.	1990	7408'
13-3/8" INTERMEDIATE	72# / P110	7400 PSI.	1480 PSI.	1990	8381'
11-3/4 LINER	65# / S-95	6920 PSI.	1384 PSI.	1990	TOP 8009' BTM 11,905'
9-5/8 PRODUCTION	53.5 / S-95	9410 PSI.	1818 PSI.	1990	12010'
7" LINER	35# / P-110	13700 PSI.	2740 PSI.	1990	TOP 11860' BTM 12479'
5" LINER	18# / P-110	13940 PSI.	2788 PSI.	1990	TOP 12,440' BTM 12837'

13-3/8 SETTING DEPTH 8381 MD. 8277 TVD.

11-3/4 LINER TOP 8009' MD 7932' TVD BTM 11905' MD 11580' TVD

MUD WEIGHT IN 13-3/8" X 9-5/8" ANNULUS 13.5 PPG.

COLLAPSE 9-5/8 CSG. 8850 PSI

CAPACITY 13-3/8 X 9-5/8 ANNULUS BBLS PER FOOT = ***0.0575***

PSI PER BBLS OF FLUID= ***12.2***

PORE PRESSURE OF 13-3/8 CSG SHOE. ***13.5 PPG. = 5568*** psi

PORE PRESSURE OF 11-3/4 CSG SHOE. 16.5 PPG = 9935 psi.

HYDROSTATIC PRESSURE AT 11-3/4" CSG SHOE = ***8129*** psi

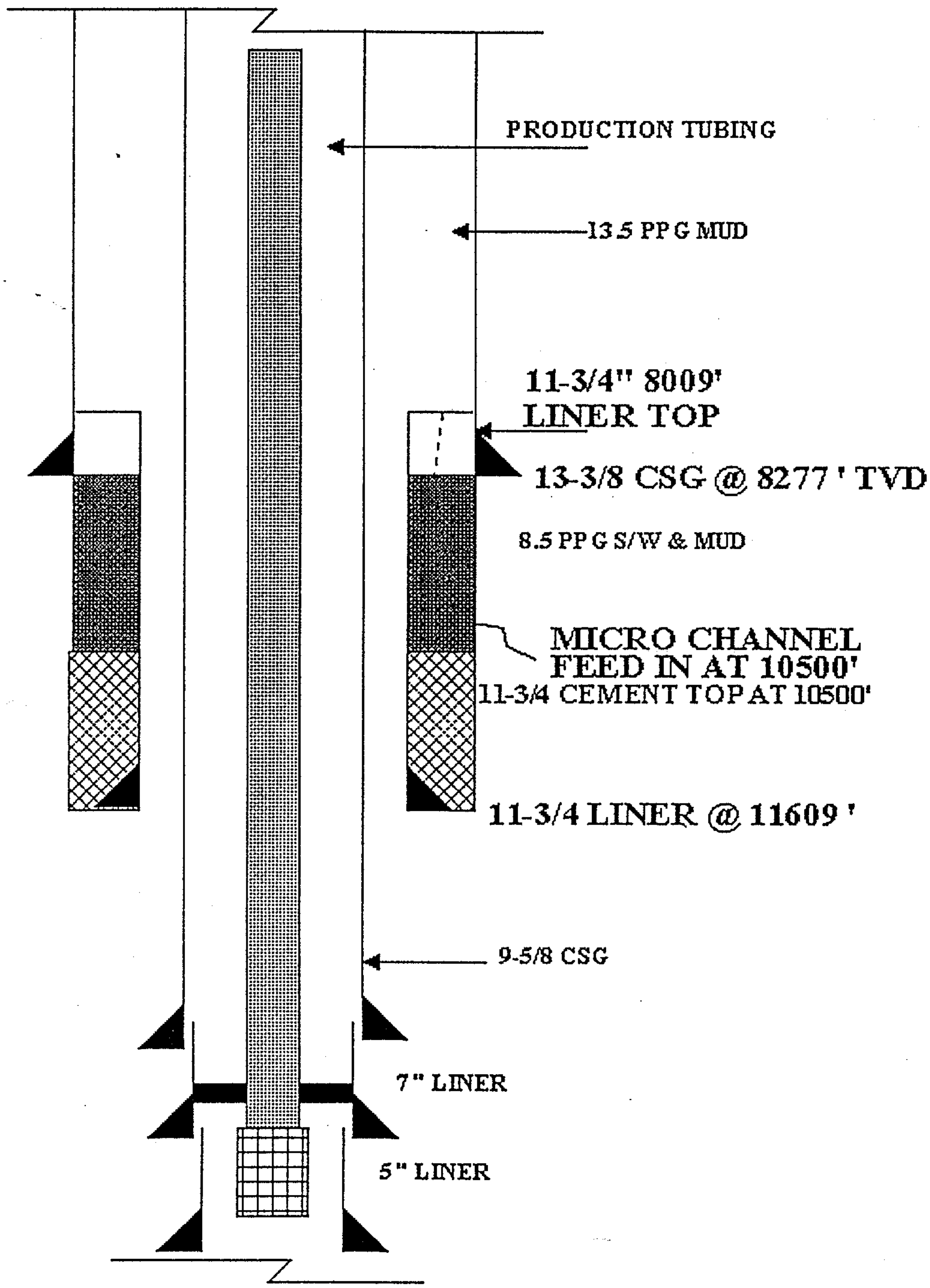
13-3/8 CASING PRESSURE DATA ANALYSIS

Formation Pressure Calculations :

13-3/8 csg shoe bottom hole pressure, 7932' TVD 12.7 ppg pore pressure = 5238 psi
13-3/8 csg shoe Hydrostatic pressure of 13.5 ppg mud, at 7932' TVD = 5568 psi
Hydrostatic to bottom hole pressure underbalanced at 10500' TVD of = 1487 psi
Hydrostatic pressure due to salt water mixture in 11-3/4 annulus = 1135 psi
Hydrostatic pressure of 13.5 ppg mud left in annulus at 7932 TVD = 5568 psi
Formation pore pressure at 10500' TVD 15 ppg equivalent mud weight = 8190 psi

Depth (ft)	Pore(Formation) Pressure (MWE)ppg	Fracture Pressure (MWE)ppg
5500'	10.0	15.0
7000'	11.4	15.9
7932'	12.4	16.8
8350	12.7	17.0
9000'	13.5	17.5
10500' start of micro channel	15.0	18.0
11580' 11-3/4 csg shoe	16.6	18.1
11649' 9-5/8 csg shoe	16.6	18.1

WELLBORE SCHEMATIC OF HI 571-A-17 MICRO CHANNEL IN 13-3/8 ANNULUS



Surface Equipment and Operations

SAFETY

When CNG started working on the idea of eliminating casing pressure by frequent bleeding and the injection of 19.2 ppg Zinc Bromide into the annulus, our 1st concern was for the safety of the personnel on the platform. We also knew that this project would be very time consuming and wanted to ensure that our field people had the proper surface equipment to monitor pressure changes and have an alarm when the pressure on the 13 3/8" annulus exceeded the respective set points. To save time and possible accidents from having to rig up and rig down each time we needed to bleed off pressure and lubricate the Zinc Bromide, a permanent valve and manifold system was installed. All of the Surface Equipment outboard of the original casing valve has a working pressure of 10,000 #, the same as the well-head.

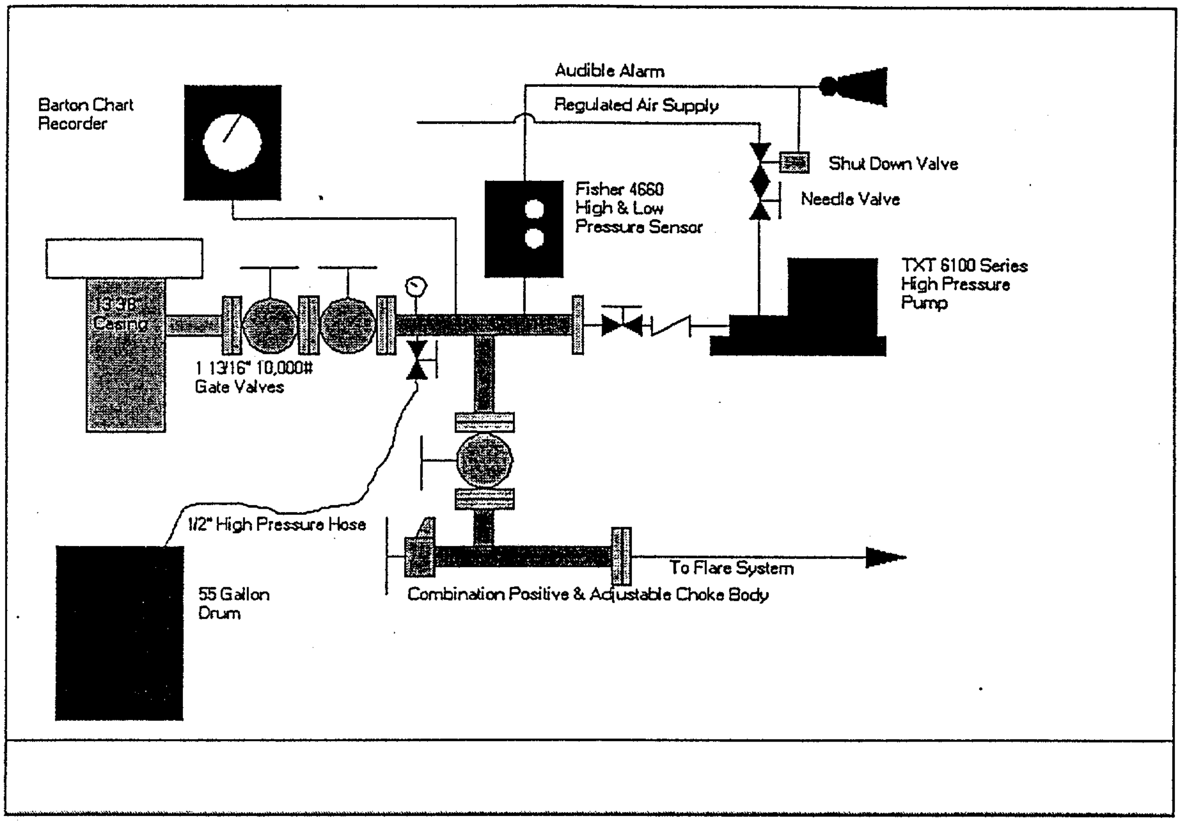
An Operations Manual and an Emergency Contingency Plan were written. The Operations Manual has guidelines for the field personnel to follow concerning routine bleeding and lubricating of the Zinc Bromide into the annulus. The Emergency Contingency Plan covers the steps that will be taken in the event that while conducting this project the pressure would increase above 5500 psi due to casing or cement failure or any other undesirable event. This plan is kept on file at H/I 571, Houma and New Orleans offices.

EQUIPMENT INSTALLATION

- 2 - 10,000# 1 13/16" Gate Valves
- 10,000# 3 way Manifold
- TXT High Pressure Injection Pump
- 10,000# High/Low Pressure Sensor
- 10,000# Adjustable/Positive Choke
- Chart Recorder
- High Pressure Hoses

Permanently installing this equipment provides CNG with a way to accurately measure and monitor any changes in casing pressure. It also allows more time for our field personnel to conduct their other platform duties.

H/I 571 A-17 13 3/8" CASING BLEEDOFF AND PUMP IN MANIFOLD INSTALLATION



GATE VALVES

Two 1 13/16" 10,000 # gate valves were installed. One is piggy backed to the original casing valve for a backup. The second valve is installed down stream of the manifold and remains closed until we bleed off the pressure.

VALVE MANIFOLD

A manifold was fabricated so that we could attach valves, gauges, pressure recorder and sensors, a choke and a high pressure pump to.

HIGH PRESSURE PUMP

The pump, we are using is a TXT 6100 series high pressure positive displacement pump with a 1 1/4" plunger. This pump pumps slow enough so that we can effectively lubricate 20 to 25 gallons of 19.2 ppg Zinc Bromide into the annulus after we conduct a bleed off.

PRESSURE SENSOR

A Fisher 4660 High & Low Pressure Sensor was installed on the manifold. This instrument was installed to alert personnel when pressure settings were reached or exceeded. It also prevents someone from having to constantly monitor the casing. The instrument is very accurate and has two pressure setting dials calibrated in 500# increments on the face of the instrument. Changing pressure settings is quick and easy because the operator does not have to hook up an external pressure source to verify new set points each time the setting are changed. The instrument is checked every 7 days and calibrated if necessary.

After each bleed off the High Pilot is set to alarm when the pressure increases to 3500 psi. This alerts the platform operators that a bleed off is due. In the event that something catastrophic was to go wrong down hole causing a sudden increase in the casing pressure, the operator will see this when he silences the alarm. The High Pressure Sensor will also shut down the pump. The pump is manually operated but, the PSH prevents the casing from being accidentally over pressured.

The Low Pressure Sensor is set at 2500 psi after each bleed off is completed. The reason for the low pressure setting is to prevent the annulus from accidentally being bled lower than 2500 psi. In the event that the block valve down stream of the manifold would leak or not be properly closed the pressure could be accidentally bled to 0 psi without anyone knowing. By allowing the pressure to be bled lower than 2500 psi at this stage could introduce another gas bubble to the annulus and void all of our efforts thus far.

CHOKE BODY

A combination Positive & Adjustable Choke Body is installed so that the bleeding of gas can be directed to the flare system. The choke has a tapered head with a 12/64 ID. The tapered head of the choke gives us a positive shut off and prevents some one from bleeding the annulus off too quickly because of the small ID.

CHART RECORDER

A Barton chart recorder was installed on the manifold at the start of the project and all of the charts are kept on file. These charts are used by the operators to enter daily pressure build ups and times between each bleed off into the log books and computer. It is also a valuable tool for plotting the progress of the project.

HIGH PRESSURE HOSE

A 1/2" high pressure hose is used when bleeding any fluid from the annulus. This is done in a 55 gallon drum so that we can accurately measure how much fluid we remove.

ZINC BROMIDE

Zinc Bromide is ordered in 25 bbl. transporters at a cost of $11,000 per transporter. Zinc Bromide is a corrosive fluid. A corrosion inhibitor is added to each transporter that is ordered.

BLEED OFF & LUBRICATING PROCEDURES

Before any bleed off is started the Production Foreman and or the Head Lease Operator are notified by the operator. Currently, when the pressure increases to 3500 psi we start the bleed off procedure.

Using the adjustable choke we bleed the gas slowly to the flare system while constantly checking for fluid using a 1/2" needle valve installed on the manifold. When fluid is detected, the adjustable choke is closed and the fluid is then bled into a 55 gallon drum through a 1/2" 10,000# hose. After a couple of gallons have been removed, we weigh the fluid to ensure that we are not removing any heavy fluid. We continue to bleed the pressure down to 2500 psi, usually removing 20 to 40 gallons of fluid per bleed off. The fluid we have removed has never weighed more than 9.5 ppg. This procedure usually takes a couple of hours to complete.

Once we have taken the pressure down to 2500 psi the High Pressure Pilot is set at 3000 psi and we manually start lubricating the Zinc Bromide into the annulus. Our policy is not to raise the pressure by more than 1/2 of what was just bled off. In this case the Zinc is lubricated into the annulus until the pressure reaches 3000 psi. The High Pressure Pilot prevents the operator from accidentally raising the pressure above 3000 psi. Our reasoning behind this is to lubricate as much Zinc into the annulus while leaving the pressure low enough for the gas bubbles to continue their migration to the surface while maintaining a constant bottom hole pressure.

Once the pump is shut off the High Pilot is then reset to 3500 psi and the Low Pilot is checked and set to 2500 psi.

MAN POWER & COSTS

The Field Foreman assigns 1 man each hitch to oversee the casing pressure project. This is usually a 12 hour per day job. We have 6 wells currently approved by the MMS using the "Stair Stepping Method". CNG's policy is that the night man does not do any bleeding or pumping into the casing, only monitoring. If the need arises the employee assigned to the project is awakened and will then assist the night man.

We have kept a log book for each well and pressures are recorded 4 times a day. Detailed remarks are also kept on times between each bleed off, length of time to bleed, weight and amount of fluid removed.

To Date This project has cost CNG Producing Company $ 91,000 . This includes the valves, chokes, manifolds, hoses, instrumentation and the Zinc Bromide.

Major Points Of Stair Step Casing Pressure Procedure

Time required to achieve casing pressure reduction and volume of 19.2 ppg Zinc Bromide

Cost

Man power requirements

Detail study of casing pressure data and probable cause of sustained casing pressure

Contingency planning

WELL CONTROL INTERVENTION FOR WELLS WITH CASING PRESSURE AND/OR FAILURES

Introduction

Casing pressure problems as related to well control generally fall into 2 categories: pressure that exceeds the rating of the casing without failure and pressure that causes casing failure. Casing pressure that does not exceed the rating of the casing does not generally cause extensive well control operations and can be remedied by more conventional type workover operations. Casing pressure that exceeds the rating of the casing and does not cause casing failure is a serious well control event that can normally be cured by a snubbing while diverting or some sort of pumping operation. When the rating of the casing is exceeded to the point that the casing ruptures or collaspes, the well control intervention effort can be quite lengthy. This can be especially true for casing failures related to corrosive problems.

Causes of Casing Pressure

There are various causes of casing pressure. Some of the more common ones are:

1. Wellhead seals
2. Cement failure
3. Mechanical casing failure
4. Corrosive casing failure

Well control procedures and techniques to deal with these different types of casing pressure vary from well to well depending on a *wide* variety of circumstances. However, there are some generalizations that are common to each type of failure that can be addressed.

Wellhead Seals and Cement Failures

This cause of casing pressure may be a more common one throughout the Gulf of Mexico and even the world. Loss of wellhead integrity through a wellhead seal is common. Diagnosis of the failed component is relatively easy through monitoring the well's operating conditions and response to relatively simple bleeding techniques. The problem is usually easily repaired by a wellhead service technician but may involve the use of a rig to either remove the tree and wellhead.

Cement failure is another cause of casing pressure. This can be through a microannulus in the cement to casing bond or an actual channel in the cement itself. These types of failures generally require some type of squeeze cement job to repair. Once again, a rig is usually needed, although some remedial jobs are now being done with coiled tubing units. The associated pressure with both of these types of failure is the kind that generally builds slowly and can be bled off to very low pressure (or even 0 psi) at least for a short period of time. Wellhead and cement failures are common and should be carefully monitored until they are repaired.

Mechanical and Corrosive Casing/Tubing Failures

The causes of mechanical and/or corrosive type of failure is almost limitless. They include parted casing, packer an/or seal assembly failures, leaking tubular connections, and the list goes on and on. These failures are almost always a precursor to an underground or surface blowout if not repaired in a timely manner.

Casing pressure failure related to a mechanical failure of the tubing or downhole equipment can be much more serious. This type of pressure is difficult or impossible to bleed off and returns quickly. Production casing is usually designed to withstand this casing pressure but failures have been known to occur. One of the more famous and costly blowout in history occurred when the tubing on a production well ruptured and all of the casing strings subsequently failed and launched the Xmas tree. In wells where the casing pressure exceeds the rating of the casing, the burst can be close to the surface or at the bottom of the string. When the casing fails at the surface and conditions are such that all of the damaged pipe can be removed, the well is a candidate for some sort of capping intervention. When the pressure at the surface plus the hydrostatic pressure of the fluid in the casing exceeds the rating of the casing, the failure may be at the bottom of the string. One way to alleviate this problem is to have a relief valve at the surface on the casing. This arrangement has been used in the past on land where the relief valve had a flow line to a pit. Offshore environments are not quite as easily configured with this type of relief system but many applications for this exist.

Wells that have casing failures relating to some sort of corrosion can be very difficult to cure. Hydrogen sulfide and carbon dioxide can be extremely corrosive even in small quantities. These wells are often difficult to control and kill due not only the nature of the fluids involved, but the downhole well conditions they predicate.

Corrosive Failures

Wells with casing pressure due to some sort of failure due to corrosion have caused extremely complicated and lengthy intervention projects in the past. Corrosion can occur not only at the surface but also downhole. When corrosive and/or toxic fluids are involved, operations to mitigate that are normally easy to perform take on a new dimension, especially in offshore locations. Tools such as a relief valves on the casing can not always be used to cure the problem. If left unchecked for too long, the condition of the wellbore will degrade to the point that there will be multiple casing string failures. This can lead to either an underground or surface blowout. Diagnostic evaluations into the cause of the casing pressure should be done as soon as the problem is discovered if the well contains any CO_2 or H_2S.

Once the problem has progressed to a critical stage, sophisticated well control procedures are required to remedy the casing pressure. Wells of this type often can usually withstand little to no surface pressure. The total loss of competent pressure containment often mean that the well will need to be diverted during the intervention. This can be difficult in the offshore environment. Complicated equipment configurations to handle the flow are needed to keep the pressure on the well to a minimum. Snubbing is often required to contain and kill the well. Many times, the snubbing intervention involves complex fishing jobs. This type of operation in turn requires a complex snubbing unit rig up with many sets of BOPs to handle the tools and corroded tubulars.

Well Re-Entry Intervention

As previously mentioned, it is often necessary to keep the casing pressure to a minimum in order to safely handle the well. This requires diverting the well either through production or flaring. Offshore well control operations in the past have been done using both production and flaring. This involves substantial equipment configurations and procedures in order to ensure safety of the personnel involved.

Tree removal must be done in order to rig up the snubbing equipment. This process can vary from easy to extremely difficult depending upon the casing pressures involved and a variety of other factors. Once the surface equipment has been rigged up and tested, tubing removal can be undertaken. Specialized equipment such as punch rams, slip rams and shear rams are needed in order to remove the corroded tubing.

Well Killing Intervention

Well kill methods vary from job to job. The first determination that must be made when a well with casing pressure is a problem is the presence or absence of underground flow. Diagnostic evaluation as to the extent of the underground flow is critical as to the method used to kill the well. Often times the flow is dependent upon the extent and type of the casing failure. As previously mentioned, this can be determined by examination of the well behavior while pumping and/or bleeding the casing pressure.

Dynamic kills are one of the tools used in this type of well. Dynamic kills require specific data regarding the wellbore configuration, the flow path of the well fluids, the reservoir characteristics and specifics regarding the reservoir and kill fluids. The downhole condition of the wellbore is critical in this type of kill in order to safely kill the well without causing further casing damage. Pumping pressures must be carefully examined and monitored throughout the job. Casing pressures on all of the casing strings in the well should be carefully watched. Contingency plans for abnormal and unexpected conditions should be a routine part of the dynamic kill planning phase.

Another method used to control wells with casing pressure include the use of a kill packer. This may require the use of special flow subs in the kill string above the kill packer so that the well can be kept on diversion and the casing pressure can be kept to a minimum. This method has been used with varying success depending on the nature of the pressures involved and their relation to the conditions of the well.

Conclusions

Casing pressure may be a symptom of more serious downhole conditions that can lead to very serious well control situations. This is especially true for wells that have corrosive fluid streams. Personnel involved in the day-to-day operations of wells should carefully identify, monitor, and track all sources of casing pressure. Early diagnostics and intervention are the key to ensuring that all sources of casing pressure are correctly identified and cured.

November 12, 1996

Schedule for Completing Blowout Prevent (BOP) Study
and Issuing New Requirements

Event	**Date**
Contractor Submits Draft-Final Report on BOP Performance	November 15
Comments on draft-final report from Technical Assessment Group (TAG)	December 2
MMS and TAG meeting with Study contractor	December 10
Publish Notice for BOP workshop in Federal Register	Mid December
Final Report	December 20
BOP workshop - Held at MMS Regional Office in New Orleans	January 15
Issue new BOP requirements (probably an NTL)	February 14

STATUS REPORT- SUPPORT "O" TRAINING REGULATIONS

by

Joseph Levine, *MMS*

PREFACE

Anticipated changes in subpart "O" of MMS regulations are still pending. Since changes in the current regulations are expected in the near future, Mr. Joseph Levine has withdrawn his presentation for the 1996 LSU/MMS Workshop. In place of his presentation, Mr. Levine has submitted the following message by fax.

-ATB November 19, 1996

A MESSAGE CONCERNING SUBPART "O" FROM MR. LEVINE

SUBPART - O -- TRAINING UPDATE

The final Subpart O- training rule will amend MMS regulations governing the training of lessee and contractor employees engaged in oil and gas and sulphur operations in the OCS. MMS is amending these regulations to simplify the training options and to provide flexibility to use alternative training methods.

A proposed rule was published by the MMS on November 2, 1995. During the 90-day comment period that ended on January 31, 1996, the MMS held a workshop. The workshop, held on December 6, 1995 in New Orleans, Louisiana received excellent participation from industry and training schools.

The MMS anticipates publication of the final rule in the *Federal Register* in the near future. Once published, MMS plans to hold another workshop with the industry and training schools to discuss the final rule.

For additional information, please contact Mr. Joseph Levine, MMS at (703) 787-1033.

WORKSHOP EVALUATION FORM, DAY 1

Session	Evaluation of Workshop Activity				Comments
	Excellent	Good	OK	Poor	
Sustained Casing Pressure: Review of Problem					
Current Regulatory Requirements and Operational Guidelines					
Current Methods for Analysis and Remediation					
Mechanisms for Long-Term Gas Migration Behind Casing					
Applications of Blast Furnace Slags in Preventing Fluid Migration Behind Casing					
Case History of Well with Sustained Casing Pressure: Volumetric Kill Using Zinc Bromide					
Case History: Abandoning a Well with Sustained Casing Pressure					
Industry Input and Operational Considerations					
Progress Report on Study of BOP Test Frequency					
Status Report- Support "O" Training Regulations					
Site Visit to Research Facility					

GENERAL COMMENTS AND SUGGESTIONS:

Please indicate your category below

- ☐ MMS Headquarters Representative
- ☐ MMS Pacific Region Representative
- ☐ MMS Gulf Coast Region Representative
- ☐ Research Industrial Sponsor
- ☐ Industry Representative

(PLEASE USE BACK OF FORM IF NEEDED.)

OVERVIEW OF LSU RESEARCH PROGRAM ON WELL CONTROL

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OBJECTIVE

The purpose of this presentation is to review our five year research plan, the progress which has been made to date, and the work planned for the coming year. The project is a continuation of an on-going research effort being conducted at the Petroleum Engineering Research and Technology Transfer Laboratory on the LSU Campus. The LSU/MMS Blowout Prevention Research Well Facility is part of this laboratory. Portions of the overall research effort are being supported by the petroleum industry and by the State of Louisiana.

INTRODUCTION

The current project is focused on well control problems associated with underground blowouts. An underground blowout differs from a surface blowout in that the uncontrolled flow exits the well beneath the surface rather than at some point above the seafloor. The formation fluids enter the well at one point and exit the well at another. The exit point could be a fractured formation, a failed cement seal, a failed casing connector, or a rupture in the casing. Such blowouts are more numerous than surface blowouts, and sometimes are a contributing factor to surface blowouts. A recent paper by Danenberger (1993) reported that the fracturing of subsurface formations which allowed gas to escape to shallow sediments or to the seafloor was a contributing factor in 24.1% of the surface blowouts occurring on the outer continental shelf between 1971 and 1991.

The flow of salt water outside of the conductor casing string is also a severe problem in deep water drilling in some areas of the Gulf of Mexico. In some cases, more than half of the cost of the deep water exploratory well is associated with controlling flows outside the shallow casing strings and getting a satisfactory cement job on these strings. Subsea videos taken by remote operated subsea vehicles have shown volcano shaped craters formed near several wells experiencing this problem. Cratering due to such flows could be a serious hazard to the foundations of a deep water production facility.

The technology of designing a well kill for an underground blowout is not nearly as straightforward, or as understood, as conventional kick control. Often the well remains under pressure for a long period of time, and the subsurface well conditions are more difficult to determine from the surface pressure. This can lead to an increased risk of personnel error before the underground flow is corrected. The three main control techniques currently used are (1) bull-heading, (2) dynamic killing in which a region of heavy mud is placed near bottom, and (3) placing plugging agents such as a barite pill or cement in the well. The design of the well kill is often more by trial and error than through the use of a standard calculation procedure. The development of good well control training modules in the area of underground blowouts has been difficult because a systematic approach has not yet been defined.

In some cases involving underground blowouts, the problem may never be fully resolved, and an underground flow may continue after the well is abandoned. Such situations are often difficult to detect until a well is drilled at a later time and finds unexpected pressure at a more shallow depth. Significant loss of natural resources as well as potential environmental damage can result from undetected underground flows that continue for long periods of time.

RESEARCH GOALS

The overall goal of the proposed research program is to foster technology improvements and safety in the development of new oil and gas reserves from the U. S. Outer Continental Shelf and the 200-mile Exclusive Economic Zone while minimizing the risk to the marine environment and the waste of our natural resources.

Long Range Objectives

The long range objective of the proposed research is the development of improved methods for detecting and quickly stopping an underground blowout through (1) improved field data interpretation methods, (2) the development of a more systematic approach to the design of a well-kill operation for underground blowouts, and (3) the development of improved well control training modules. The research would address both drilling and production operations. Within each of these two main areas, work would be done on prevention, detection, remediation, and post analysis of well control problems associated with underground blowouts.

RESEARCH PLAN

An overall five-year research plan has been developed to accomplish the goals and objectives of this program. Implementation of the plan will be accomplished through joint industry, government, and academic support. The proposed research on underground blowouts has beeen broken into a number of tasks and subtasks. These tasks are described below.

Task 1- Density, Strength, and Fracture Gradients for Shallow Marine Sediments

One of the most difficult aspects of underground blowouts is the possibility of the underground flow breaking through the shallow sediments outside of the casing and reaching the surface. In this way, the underground blowout can become a surface blowout, thus increasing the risk to field personnel and to the environment. In extreme cases, the structural integrity of the wellheads and bottom supported platforms is undermined and the entire installation may be lost. The most important parameter controlling this type of catastrophic failure is the breakdown pressure of the shallow sediments. The breakdown pressure is known to be strongly dependent on the density of the shallow sediments.

In the past, formation breakdown pressure of the shallow sediments have been routinely estimated by extrapolating fracture gradient correlations developed from data on sediments deeper than 1000 meters. The estimated values for formation breakdown pressure determined in this way is very low, and this has affected the industry's designs and practices associated with shallow underground blowout situations. Standard leak-off test techniques for measuring the formation breakdown pressure have usually been avoided in the shallow sediments for fear of causing a sediment failure that would be difficult to repair.

Recent studies have indicated that the breakdown pressure of shallow sediments is often higher than expected. The primary objective of this task is to develop a database of density, strength, and breakdown pressures of shallow marine sediments in order to provide a more realistic basis for shallow well design. One objective of this task is to develop a database program which would permit a quick visual evaluation of a proposed casing program. Such a database would aid greatly in the determination of the risk for an underground blowout associated with a proposed casing design and diverter contingency plan. A second objective of this task is to develop a shallow leak-off test model. Such a model would be used to develop a recommended practice for conducting leak-off tests in shallow sediments.

Subtasks 1a: The Development of a Soil Borings and Fracture Gradient Data Base

The objective of *Subtask 1a* is to organize leak-off data, shallow sediment density data, and other indications of formation breakdown strength into a database. Emphasis is being placed on the upper 1000 meters of sediments and on marine sediments in deepwater. Since few operators routinely measure the formation breakdown pressure of the shallow sediments, other indicators of formation breakdown pressures are also being investigated. Information concerning the heaviest mud density successfully circulated after setting conductor casing as well as information concerning cement densities successfully circulated to the surface or seafloor when cementing surface casing is being collected. This subtask was performed in 1994, but additional data is being added to the database as it becomes available.

Subtasks 1b: The Development of a Shallow Leak-off Test Model

The objective of *subtask 1b* is to develop a mathematical model which may be used to predict the behavior of leak-off tests conducted in shallow sediments. Shallow leak-off tests cannot be analyzed using the theory developed for elastic rocks. A simplified analysis of a shallow leak-off test has been based on the assumption that for shallow marine sediments effective principal stresses are equal. The assumption is merely a special case for plastic rocks. Since shallow sediments are most likely in a plastic state of stress, plastic theory should be used for leak-off test analysis. Therefore, the development of a method for analyzing shallow leak-off data is underway. Once verified using the data available from soil borings and leak-off tests which were compiled during *subtask 1a*, this model will be used to develop a recommended practice for conducting leak-off tests in shallow sediments.

To develop a simplified analytical model of the complex well-rock system around the casing shoe, the simplified formulas derived are being verified by a more rigirous finite element model of the system. To date, the research team has successfully derived and verified simplified fromulas which predict the horizontal in-situ stress in plastic sediments. These fromulas relate the leak-off pressure data to plastic properties such as cohesion and angle of internal friction.

An experimental study of the potential damage to the integrity of a cement seal as a result of leak-off testing in soft upper marine sediments is also underway. To date, the study has shown that an annular channel can be initiated around the casing shoe. The next step will be to define the conditions which may potentially lead to propagation of the annular channel upwards behind casing. Once these conditions are known, guidelines for conducting a non-damaging leak-off test will be established. This subtask was started in 1995, and progress will be reported at this workshop.

Subtask 1c: Internet Access of Database with GIS System

In *Subtask 1c*, work would begin on integrating the database with a Geographic Information System for fast and efficient retrieval of past leak-off test data in a given area. The data retrieved would be displayed in a form that would permit a quick visual evaluation of a proposed casing program. Data collection would also be continued. This subtask has recently been started and GIS systems suitable for the database are being investigated. Much of the data in the database was made available by the operators without the exact well name and location being identified. Therefore, the geographic sorting will be done by offshore areas rather than by exact coordinates.

Subtask 1d:Database Testing and Documentation

In *Subtask 1d*, the leak-off test database system would be tested, documented, and demonstrated in a Technology Transfer Workshop. A system would be developed for routine updating of this database with data from new wells drilled on the OCS. This system could eventually be used for verification of casing program design and diverter contingency plans.

Task 2- Prevention of Flow after Cementing Surface Casing

Current well control practice for bottom-supported marine rigs usually calls for shutting in the well when a kick is detected if sufficient casing has been set to keep any flow underground. Even if high shut-in pressures are seen, an underground blowout is preferred over a surface blowout. On the other hand, an operator on a bottom-supported vessel will put the well on a diverter if he believes that the casing is not set deep enough to keep the underground flow outside the casing from breaking through the sediments to the surface. Once the flow reaches the surface, craters are sometimes formed which can lead to loss of the rig and associated structures. Cratering also increases the difficulty and time required to kill the blowout.

A particularly difficult well control problem sometimes arises when flow or pressure build-up is noted on the conductor/surface-casing annulus just after cementing operations. Selecting the best procedure for a given well situation in not a well defined process and company policy is usually based on highly generalized "rules-of-thumb." Some operators currently let the unset cement unload on a diverter, others elect to keep the well shut-in, and others will bull-head mud down the conductor-surface casing annulus. There continues to be periodic accidents, spills, and economic losses related to this problem.

A previous LSU/MMS project identified the four main sediment failure mechanisms that can lead to cratering as (1) borehole and fracture erosion, (2) sediment liquefaction, (3) piping, and (4) caving due to borehole failure and sand production. While all of these mechanisms contribute to crater formation, caving due to sand production appears to be the most important mechanism leading to the formation of large craters that result in loss of a platform or jackup rig. When borehole pressure is lost, shallow water sands begin to produce and borehole enlargement in the sand sections results from unconsolidated sand being carried out of the well with the produced water. In one documented case occurring on land, produced sand was spread over 100 acres and was 40 inches thick near the edge of the crater. Borehole enlargement in the sand and silt sections lead to collapse of the overlying clays into the enlarged hole. Once the overlying clay has slumped into the open section, it too can be more easily washed from the hole.

Examination of a few case histories has shown evidence that cratering can develop below conductor casing having about 500 feet of penetration below the mudline even when the well is not shut-in. Release of the surface pressure promotes flow from the exposed water sands which triggers the borehole enlargement mechanism discussed above. Another case history involving flow after cementing of surface casing indicated that significant surface pressures can be held on conductor casing without the development of a large crater.

Many operators now shut-in kicks taken below conductor casing on floating vessels, but not on bottom-supported rigs. This preliminary study has indicated that at least in some cases, it may also be best to shut-in a kick taken below conductor casing on bottom-supported rigs. It is believed that a more in-depth study of available case histories is in order to determine if risks of cratering could be reduced by an improved contingency planning procedure for the kicks taken below conductor casing. A first step in this direction would be a study of kicks taken while cementing surface casing. It is believed that more examples in which the operator shut-in the well for this situation exist. Other cases of interest would be kicks taken below conductor casing that were shut-in during floating drilling operations. However, conductor casing is often set deeper for floating drilling operations than for bottom-supported rigs.

Subtasks 2a: Analysis and Documentation of Data from Case Histories

In an effort to determine what factors contribute to flow behind pipe after cementing the surface casing, the research team searched for complete case histories supported by detailed information on well conditions, slurry properties, and the depths and pressures at which the gas inflow strata exist. The cases were limited to wells located on the Outer Contenental Shelf which have had flow behind casing within the last 20 years. Once compiled the available case histories were analyzed and documented

The wells in which flow behind casing is occurring and the wells in which no flow behind casing is occurring will be correlated using indices which represent the risk of annular flow. At present, the gas flow risk factors do not appear to offer a strong correlation with actual gas flow events. Laboratory data from service companies equipped with instrumentation with which late cement rheology and gas flow through cement can be tested are currently being sought to aid in the identification of gas flow risk factors. This subtask was started in 1995 and progess will be reported at this workshop.

Subtask 2b: Survey of Current Methods and Practices to Prevent Gas Flow after Cementing

The methodology and current practices followed in an attempt to control gas migration through cement will be studied and documented. In addtion, summaries reporting the results of a literature survey regarding the rheology of the thickening cement slurries and the permeability of the cement slurries as a function of filtration properties. Consultation with other investigators has revealed considerable work which is being conducted at other research facilities that is not yet publised. This subtask was started in 1995 and progress will be reported at this workshop.

Subtask 2c: Documentation of Promising Technology for Preventing Gas Flow after Cementing

Based on the results of the literature survey conducted in Subtask 2b, a new promising method for preventing gas migration has been selected by the research team for more detailed study. The method chosen for more detailed evaluation involves down-hole vibration of the cement slurry. The data collected using this method has been compiled from both the published literature and from an unpublised in-house study conducted by Texaco. The evaluation will be based on technical performance, feasability for use offshore, and potential limitations. Additional information is being gathered regarding the use of foam cements in areas which exhibit severe gas and/or water migration problems. This work was started in 1996, with the bulk of the work to be done in 1997.

Subtask 2d : Development of Computer Model for Estimating Risk of Crater Formation

The objective of *subtask 2d* is to develop a computer model for estimating the risk of sediment failure and cratering for a given shut-in pressure, casing plan, and sedimentary sequence if the conductor-surface-casing annulus remains closed and is not put on a diverter. Software that can be used to predict the bottomhole pressure drop and early annular gas migration will be developed based upon the results of laboratory testing with physical gas migration simulators available at several service companies. (The gas migration simulator is a device presently used by some operators for cement evaluation.) The program will estimate risk of gas crossflow or breaching to the surface for a given cement and geological condition. The program will also be used to calculate minimum requirements for cements used in a drilling area offshore to avoid early gas migration. In addition, the program will be used to analyze some of the better documented case histories of gas migration. This work was originally scheduled to start in 1998, but was given a high priority based on evaluations submitted during our last workshop. Therefore, an effort is being made to accelerate the schedule for this task.

Task 1 will support the work of Task 2 because enlargement of the LSU overburden density and leak-off test database for shallow marine sediments will lead to better prediction of fracture initiation pressures in shallow sediments.

Task 3 - Feasibility of Automated Detection of Underground Blowouts

Past research at LSU has focused on computer automation of well control operations for deepwater rigs. In deep water, the tolerance for error in the bottom-hole pressure being maintained by the choke and pump operators is usually small. This low error tolerance is due to the lower fracture gradients that are generally seen in deep water. It has been shown that choke and pump automation and control can reduce errors affecting pressure during well control operations as compared to a human operator. In this new research task, the previous work on choke automation is being extended in an attempt to achieve early recognition of the onset of an underground blowout using computer software. A recent case history showed late recognition of an underground blowout in progress during a well control operation. This led to a large influx of very volatile oil reaching the surface.

Subtask 3a: Modify LSU No. 1 Well for Study of Underground Blowouts

The objectives of Subtask 3a are to complete a literature review on automated systems that assist in detection of underground flow, to adapt LSU's research well facility to accommodate underground flow research, and to design alterations to earlier developed software to include underground flow detection or analysis. The literature study of past work on expert systems for well control applications, with emphasis on algorithms for recognizing the early phases of a underground blowout, has been completed. To test the new system, one of the research wells at the LSU well control research facility has been modified to accomadate the modeling of underground flow. This work was done in 1994 and was reported in our previous workshop held on May 23-24, 1995.

Subtask 3b: Update Well Control Automation Software to include Underground Flow Detection

In *Subtask 3b*, the automated process control system would be updated to include underground flow detection and demonstrated at an annual workshop. The applicable results of the DEA 49 project were incorporated into our effort to avoid any duplication of efforts already made by TRACOR in this area. This technology has been implemented in the LSU/MMS automated process control system which was developed in an earlier study. The updated controlling software greatly enhances the speed of data collection and control loop processing. This subtask was started in 1995 and will be reported at this workshop.

Subtask 3c:Modification of Gas Compression Facility for Underground Blowout Experiments

S*ubtask 3c* involves a modification of the available gas compression facilities to support the research on underground blowouts. The new compression equipment boosts the pressure of natural gas from the available pipeline pressure of 650 psi to a gas storage well pressure of about 1800 psi. The high pressure gas is then used to simulate threatened blowout events in the LSU No. 1 Well. As gas is used from the system, the gas charging system can continually rebuild the pressure. The compressor is able to charge at a rate of about 165 scf/min to meet our new experimental needs.

The old method for boosting the gas pressure to simulated bottom-hole pressure is to pump mud into the bottom of the gas storage wells using triplex cementing pumps currently available at the LSU/MMS Research and Training Well Facility. However, this technique is very slow, often requiring a day or two of preparation before a full charge can be developed. Also, only two thirds of the well volumes can be utilized for gas storage, and gas pressure cannot be restored while a threatened blowout experiment is underway. The underground blowout simulations sometimes require a continuous injection of gas at simulated bottom-hole conditions. This continuous injection cannot be sustained with our current system.

The gas compressor was bid and Norwalk Company was awarded the work. Delivery of the equipment has now been completed and piping has been fabricated to tie the compressor into our system. Use of the compression facility is now available for testing, validation, and demonstration of the underground flow detection system. This subtask was started in 1995 and will be reported at this workshop.

Task 4 -Subsurface Logging Methods for Verifying Underground Blowouts

Once surface indicators such as drill pipe pressure, casing pressure, and pit gain suggest that an underground blowout may be occurring, the next step is to verify the underground blowout with subsurface measurements. To determine the depths at which the formation fluid enters and exits the well and the magnitude of the subsurface liquid and gas flow rates is generally desirable. Currently available tools that can be run inside the drillstring include noise logs, temperature logs, and nuclear gas-detection logs. However, interpreting the data obtained from these tools is often difficult, and sometimes conflicting results are obtained.

In *Task 4*, a recommended practice for employing and interpreting currently available logging tools would be developed. This project would seek to develop heat flow models specifically for underground blowouts that are in the public domain and readily available for timely interpretation of field data. An accurate estimate of the subsurface flow rates during an underground blowout is needed to properly design a successful well kill operation. *Subtask 4a* would give emphasis to temperature logging methods and interpretations. *Subtask 4b* would give emphasis to Noise Logs. These subtasks are scheduled for 1997 and 1998 respectively based on priority levels assigned at our last workshop.

Task 5 - Interpreting Surface Pressure During an Underground Blowout with an Oil-Base Mud

A recent case history of an underground blowout has shown that changes in surface well pressure are more difficult to interpret when an oil-base mud is in the well. The LSU Well Control Research Group participated in DEA Project 7, which collected considerable down-hole well data for gas kicks in an oil-base mud. The time restriction on publication of this data has now passed. This project would consist of analyzing and interpreting the DEA 7 Project data and making the results available to industry through technical publications. The lessons learned in the DEA Project 7 should enhance our ability to interpret surface pressure data during an underground blowout with an oil-base mud in the well. This subtask is scheduled for 1998 based on priority levels assigned at our last workshop.

Task 6 - Study of Use of Bull Heading Procedure for Underground Blowouts

The Bull-heading procedure has been used successfully on some case histories involving underground blowouts. This project would involve developing a computer model for predicting viability of this procedure for a given field situation. It would employ a counter-current gas slip velocity correlation developed from a currently on-going project. *Subtask 6a* involved computer model development and the design of an experimental program for verification of the model in one of our research wells. This work has been completed and was reported in our previous workshop held on May 23-24, 1995. In *Subtask 6b*, the model would be tested, updated as necessary using the well test data, and technology transfer activities initiated. A recommended practice would be developed for designing a bull-head kill operation. This subtask is scheduled for 1998 based on priority levels assigned at our last workshop.

Task 7 - Experimental Evaluation of Plugging Techniques for Underground Blowouts

In practice, attempts are often made to plug the bottom portion of a well experiencing an underground blowout by means of a barite pill, gunk pill, bengum pill, or other plugging agent. The size of the pill and the placement speed are determined by trial and error. In many cases, plugging is not achieved after several attempts. *Task 7* would involve seeking out and evaluating field records of plugging attempts made in an attempt to identify the most successful plugging agents and placement techniques. Several new formulations of the older plugging agents have recently been developed by blending various polymers with the bentonite and oil mixtures. A goal of this task will be the development of a recommended practice for designing a plugging treatment for an underground blowout. This subtask is scheduled for 1997 based on priority levels assigned at our last workshop.

Task 8 - Requirements for Dynamic Kill of Underground Blowouts

The current model used for contingency planning of dynamic kill operations often does not perform satisfactorily for a case involving an underground blowout because it is necessary to assume that the pressure in the fracture is independent of kill rate. Also, several case histories have shown that underground blowouts often involve stripping operations before a dynamic kill can be undertaken. Numerous well control problems associated with drill string safety valves used prior to stripping operations have been documented. Thus, a study of improved safety valve designs was added to this task.

In *subtask 8a* the dynamic kill computer simulator that was developed in a previous project was modified to include a representative hydraulic fracture model. In addition, an experimental test for verifying the model in our research well was designed. The results of subtask 8a was presented last year at the 1995 LSU/MMS Well Control Workshop.

In *subtask 8b* the computer model developed in subtask 8a will be verified using the new experimental well configuration. In addtion, a recommended practice for designing a dynamic kill for an underground blowout will be developed. This work is scheduled for 1997 based on priority levels assigned at our last workshop.

In *subtask 8c* development of an improved drill string safety valve design is underway. This subtask includes a review of the current drill string safety valve designs, design of a test stand, testing of current valve designs, and development of a prototype design for a new safety valve. To date, the review of currently existing safety valves and the design and construction of a test stand has been completed. Testing of the existing safety valves is currently underway. A low-torque prototype valve has also been proposed. A report on this subtask will be presented at this workshop. It appears that this work may need to be expanded.

Task 9 - Review of Recent Diverter Failure Rate and Failure Mode

An important aspect of the decision to use a diverter for the prevention of a shallow underground blowout is the reliability of the diverter system being used. In *Subtask 9*, diverter failures since the last report on this topic would be analyzed to determine if reliability has been improved. Failure mechanisms such as plugging and erosion would be summarized. Modern diverter configurations currently in use would be documented from available MMS records. This work is scheduled for 1997 based on priority levels assigned at our last workshop.

Task 10 - Post Analysis of Recent Blowouts and Near-Misses

This task involves screening case histories of recent underground blowouts for important mistakes made and lessons learned. Five of these examples would be selected for detailed simulation and analysis. Input would be obtained from MMS personnel in selecting the case history for detailed study. A publication would be prepared giving details of the sequence of events and downhole well conditions simulated. A well-control training module would be prepared based on this case history. *Subtask 10a* would be conducted the first year for the first case history selected, *Subtask 10b* the second year, and so on. At the end of the five year project, five excellent case history training modules should be available for the well-control training programs in the petroleum industry.

Excellent case histories from Mobil Oil Company, Phillips Petroleum Company, and Amoco Oil Company have been obtained. Computer simulations are still being performed to better understand the downhole conditions that developed during the well control events. A full rig floor simulator is being provided by Computer Simulation, Inc to LSU to allow these case histories to be made available on well control simulators. A report discussing the first two case histories selected will be presented at this workshop.

Task 11 - Study of Excessive Casing Pressure Problems during Producing Operations

A significant number of producing wells in the OCS develop undesirable and sometimes potentially dangerous pressure on one or more casing strings. These problems are thought to be due to long term migration of formation fluids through cement. Because of the large scope of this problem, the research team is searching for improved methods for managing existing problems as well as assisting in the development of new technology for reducing the number of future problems.

The objective of *Subtask 11a* is to gather and compile data on excessive casing pressure waivers. Currently, information is being collected on excessive casing pressure waivers granted during the recent past. Information on each well for which a waiver was granted is being compiled into the MMS Sustained Casing Pressure (SCP) database. Data on seven wells in the OSC Pacific region with sustained casing pressure have been added to the database. Work currently underway is focused on adding missing wells to the database and developing methods of displaying the data on a geographic map. To date, the database has been used to identify operators with the most experience dealing with excessive casing pressure. Based on the data compiled in the MMS SCP database, the cause(s) of the excessive casing pressure will be analyzed. Once identified, statistics will be compiled on the common causes of sustained casing pressure.

Halliburton is conducting a Joint Industry Project involving laboratory experimentation on the mechanisms for long term gas migration through cement behind casing. It is recommended that LSU join this project so that we can keep abreast of the more confidential advanced work that is being done on the causes and possible solutions for excessive casing pressure on producing wells. This will allow the LSU Research Team to work most efficiently and avoid duplication of efforts being made by others. LSU recently attended a portion of one of the JIP meetings and discussed contractual problems that would have to be overcome before LSU could join the project.

The objective of *Subtask 11b* is to study and to document operator procedures for handling excessive casing pressure when it is detected and to review all available guidelines for periodically bleeding down excessive pressure when it is detected. Procedures currently followed in industry for handling excessive casing pressure have been discussed with a number of operators. Pressure and temperature changes introduced by completion and production operations have also been shown to contribute to the development of cracks and a micro-annulus (Jackson & Murphey, 1993 and Goodwin & Crook, 1990).

Subtasks 11a and 11b were started in 1994 and a report on this work will be given at this workshop.

Subtask 11c: Review Case Histories of Successful and Unsuccessful Remediation Attempts

The objective of *Subtask 11c* is to review the procedures used during both successful and unsuccessful attempts to remediate excessive casing pressure. The procedure used for the "stair-step" method by CNG in well A-17 is being reviewed. The LSU research team is working with several operators to obtain complete case histories on a few select wells. Specific case histories on the effects of periodic bleeding of casing pressure are also being requested. Work on this subtask was started in 1996 and will be reported at our next workshop. This area will also be addressed in the ROTAC meeting held during the first day of this workshop. Information collected during this meeting will be integrated into the work of subtask 11c.

Task 12 - Annual LSU/MMS Workshop on Well Control Research

An LSU/MMS workshop on well control research will be repeated on an annual basis (*Subtasks 12a-12*). This workshop will provide interested individuals within the petroleum industry and MMS an opportunity to review the progress being made and to recommend appropriate changes in the direction and priorities of the work.

Task PB1 - Kick Tolerance Analysis for Deepwater Drilling

The most effective way to prevent an underground blowout is through a realistic assessment of the hazards associated with the alternative well designs being considered. The kick tolerance concept has been shown to be a powerful tool that we can use in estimating the risk of an underground blowout if well control operations become necessary. Kick tolerance is defined as the maximum underbalance (differential pressure between pore pressure and mud weight in use) that can be encountered without fracturing the weakest exposed formation. Kick tolerance is usually expressed as an equivalent mud density. It is calculated assuming natural gas is the kick fluid. Also assumed is a maximum pit gain that would be expected before the blowout preventers are closed. The maximum pit gain used in the calculation is critical and must be appropriate for existing field operating practices and rig crew training. Shut-in kick tolerance applies to well conditions when the well is shut-in. Circulating kick tolerance applies to the most severe conditions expected during the well control operations to remove the kick fluids from the well.

The concept of kick tolerance is more complex in deep water drilling since dynamic position drilling vessels (DPDS) are used. Normally in this situation, a riser safety margin is applied to avoid an eventual loss of hydrostatic pressure due to an emergency disconnection and blow-out preventer (BOP) failure. Depending on water depth, leak-off test results, and pore pressure, the riser safety margin cannot always be applied because of the risk of formation fracture. In this case, the kick tolerance value can be near zero or even negative without implying a dangerous situation.

Under certain conditions, a greater risk of an underground blowout can be tolerated if it is known that control of the well could be regained using available rig equipment. The chance of being able to regain control of the well is estimated by calculating the product of permeability (k) and permeable zone thickness (h) which could be controlled using a dynamic kill procedure and the available rig pumps. The "killable kh" is routinely calculated by some operators as drilling progresses. If it is determined that an underground blowout is not likely or that if one did occur it could be controlled with available rig equipment, a deeper casing setting depth may be selected. When the number of casing string can be reduced, significant cost savings can be achieved without taking unacceptable risks of an underground blowout. Mobil Oil has successfully developed and applied the concept of killable kh when drilling multiple objectives under variant pore pressure conditions.

An advanced kick simulator that is dedicated to kick tolerance and killable kh calculations for deep water drilling is needed. It is important that the developed software be fast and reliable and suitable for available rig site computers. Experiments have to be performed to determine the gas distribution profile in the annuli, and how the shape of the distribution profile will modify along the path of upward migration. In addition, the effect of high pressure losses in the kill line has to be incorporated into the model. Finally, the killable kh factor should be an output of the computer program.

Based on our past work, two areas were identified where further study is needed to improve the accuracy of the kick tolerance calculation. One area is the amount of kick dispersion that occurs in the well due to (1) bubble break-up and (2) retention of small bubbles in the mud (as a function of gel strength). A significant portion of a typical gas kick is believed to lag behind the region of high concentration as it is circulated to the surface. This lagging effect increases the amount of kick dispersion and can significantly increase kick tolerance. Additional experimental work is needed before an accurate kick tolerance simulator can be developed.

In *Subtask PB1a*, experimental studies were conducted in the LSU No. 2 Well to provide additional data on gas-mud mixing during well control operations. The LSU No. 2 Well has 9-5/8" casing to a depth of 5,884 ft (1793 m) and has a special completion that permits a gas kick to be experimentally modeled. The well was monitored by four annular pressure sensors to measure the pressure at various points in the well during upward gas movement (both with and without mud circulation). Also, gas concentration in the mud downstream of the separator and the gas flow rate from the separator was measured. The gas flow rate metering system was designed to permit both very low and very high rates to be accurately determined. The measured data was used in modeling the gas concentration profile along the well. This work was done in 1994 and was reported in our previous workshop held on May 23-24, 1995.

Another area where improved accuracy is needed is the determination of the critical rate at which mud droplets are carried from the well, reducing the liquid hold-up to zero. Application of the three methods recently presented by Gillespie et. al. (1990) to several example well control problems has yielded a threefold spread in the computed results. In *Subtask PB1b*, experiments will be conducted in our inclined wellbore model and in the LSU No. 6 Well to study this problem. This work is scheduled to begin this year.

In *Subtask PB1c*, an advanced kick simulator designed specifically for calculating kick tolerance for deep-water wells and HPHT (high-pressure, high-temperature) wells would be developed. In addition, the use of kick-tolerance criteria both while planning the well and while drilling the well will be studied. The new software would also determine the kill capability (killable kh factor) of the available rig pumps. This work was done in 1994 and 1995 and was reported in our previous workshop held on May 23-24, 1995.

PETROBRAS has supported *Subtasks PB1a and PB1c*. However, this area was also one of very high interest and priority to MMS personnel attending our recent workshop on well control research. In the future, MMS will support *Subtask PB1b* as part of the LSU/MMS project.

Task PB2 - Feasibility Study of Dual Density System for Deepwater Drilling

As discussed previously, fracture gradients (expressed as equivalent mud weights) decrease with increasing water depth. This is due primarily by the hydrostatic pressure in the marine riser that is in excess of the seawater hydrostatic pressure acting on the sediments at the mudline. This problem has been recognized for a long time as a limiting factor on the water depth that can be explored with existing drilling systems. One possible solution that has been discussed is to place mud pumps and tanks at the seafloor, with an auxiliary pump to bring the mud to the surface for treatment. Recently, Goldsmith (1994) suggested that computer controlled nitrogen injection into the bottom of the marine riser and subsea flowlines could be used to maintain the effective density of the mud in these components equal to seawater hydrostatic. The computer system needed to do this should be no more complex than the computer system currently used for station keeping on a dynamically positioned vessel.

This project was started in 1995 with support from Petrobras and a progress report will be given at this workshop.

Task NPD - Assisting Manufacturers with New Product Developments

The research well facility also provides support to manufacturers developing new products related to well control. Since our last workshop, we have provided testing for William's Tool Company in their development of new 2500-psi working pressure sealing elements for their high pressure rotating control heads used in underbalanced drilling. We have also provided support to SWACO in their development of flow coefficient curves for their choke and choke body. This work was also needed to support new underbalanced drilling activities. Thomas Tools has also used our test loop to assist in the development of their MWD tools.

TECHNOLOGY TRANSFER PLANS

Technology transfer will be achieved through technical publications, workshops, and well control training seminars. In addition, the LSU Petroleum Engineering Department will set-up and maintain information on well control that could be accessed through INTERNET or BITNET.

TECHNICAL PUBLICATIONS

Participants in the LSU Well Control Research will submit the results of their work for publication and presentation at annual IADC Well Control Symposiums, at the annual SPE/IADC Drilling Conference, and at MMS Research and Development Conferences for Oil and Gas Operations. Special topics sessions of other SPE and ASME meetings will also be targeted when appropriate topics are available. A list of technical publications arising from the LSU Well Control Research Program is given at the end of this report.

TRAINING SEMINARS

The LSU Petroleum Engineering and Technology Transfer Laboratory also offers periodic training seminars for industry personnel. Improved methods for prevention, detection, and remediation of underground blowouts and lessons learned from previous case histories of underground blowouts that would result from the proposed research could be quickly integrated into these seminars.

WORKSHOPS

IADC sponsors periodic workshops in their Well Control Roundtable Series for individuals and organizations involved with well control training. Training modules developed as part of the proposed research will be presented to this group. In addition, periodic workshops will be held for MMS personnel. An effort would be made to develop training modules that could be completed on the job by field personnel interested in increasing their understanding of advanced well control topics. Past experience has shown that this approach would be much more effective than concentrated refreshers on a once-a-year basis.

INTERNET WELL CONTROL FILES

Timely information, training modules, and research results will be made available through INTERNET, which could be accessed from computer terminals anywhere in the world. This communication resource could also improve communication between LSU and various research sponsors. It is recognized that improved communication between LSU and MMS personnel is needed. Files could be maintained on:

- Worldwide Leak-off test results
- Shallow sediment overburden data
- Example Well Control Exam Questions
- Well Control Incident (Blowout) Database
- Training Modules on Advanced Well Control Topics
- Case Histories
- Software for Well Control Contingency Planning
- LSU Well Control Research Reports
- Bibliography (Database) containing Technical Papers on Well Control
- Near-Miss Reports from Participating Operators

Progress in this area has been slower than originally anticipated. Current plans call for increasing the manpower allocated to this area so that more rapid progress can be made.

PROJECT SCHEDULE

The estimated time table for completing the proposed work is shown in Table 1. The subtasks that have already received approval to begin from the appropriate sponsor are shaded gray.

TASK	Year 1	Year 2	Year 3	Year 4	Year 5
1. Sediment Strength Study & Fracture Gradient Database	Subtask 1a	Subtask 1b	Subtask 1c	Subtask 1d	
2. Flow after Cementing Surface Casing	2a-Prelim	Subtask 2a	Subtask 2b	Subtask 2c	Subtask 2d
3. Automated Detection of Underground Blowouts	Subtask 3a	Subtask 3b			
4. Subsurface Logging Methods for Underground Blowouts				Subtask 4a	Subtask 4b
5. Interpreting Surface Pres during Underground Blowouts					Task 5
6. Bullheading Underground Blowouts	Subtask 6a				Subtask 6b
7. Plugging Underground Blowouts				Task 7	
8. Dynamic Kill of Underground Blowouts	Subtask 8a	Subtask 8c		Subtask 8b	
9. Review of Recent Diverter Failures				Subtask 9	
10. Post Analysis of Underground Blowouts	Subtask 10a	Subtask 10b	Subtask 10c	Subtask 10d	Subtask 10e
11. Excessive Casing Pressure on Producing Wells	Subtask 11a,b		Subtask 11c		
12. Annual LSU/MMS Workshop	Subtask 12a	Subtask 12b	Subtask 12c	Subtask 12d	Subtask 12e
PB1- Kick Tolerance Analysis		Subtask PB1a	Subtask PB1b		
PB2- Novel Systems for Ultra Deep Water Drilling		Subtask PB2			
NPD- Assist Manufacturers in New Product Developments					

Table 1 - Estimated Project Schedule

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IMPROVEMENTS IN THE LSU/MMS RESEARCH AND TRAINING WELL FACILITY

by

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OBJECTIVE

The purpose of this presentation is to describe recent improvements in the LSU/MMS Research and Training Well Facility and the increased capabilities resulting from these improvements.

INTRODUCTION

The LSU/MMS Research and Training Well Facility provides a place to perform full-scale research experiments and training exercises for improved well control operations. There are six unperforated, cased wells on site ranging in depths of 1200 to 6000 ft. There are also two Halliburton HT-400 pumps, a gas compressor, five drilling chokes, two degassers and three 250-bbl mud tanks, and a 10,000-ft flow loop. Shown in Figure 1 is a photograph of the LSU No. 1 Well and the associated surface equipment and control room. A number of major improvements have been made in the facility since our last LSU/MMS Well Control Workshop held in 1995. These improvements have enhanced our ability to perform both our research and training missions.

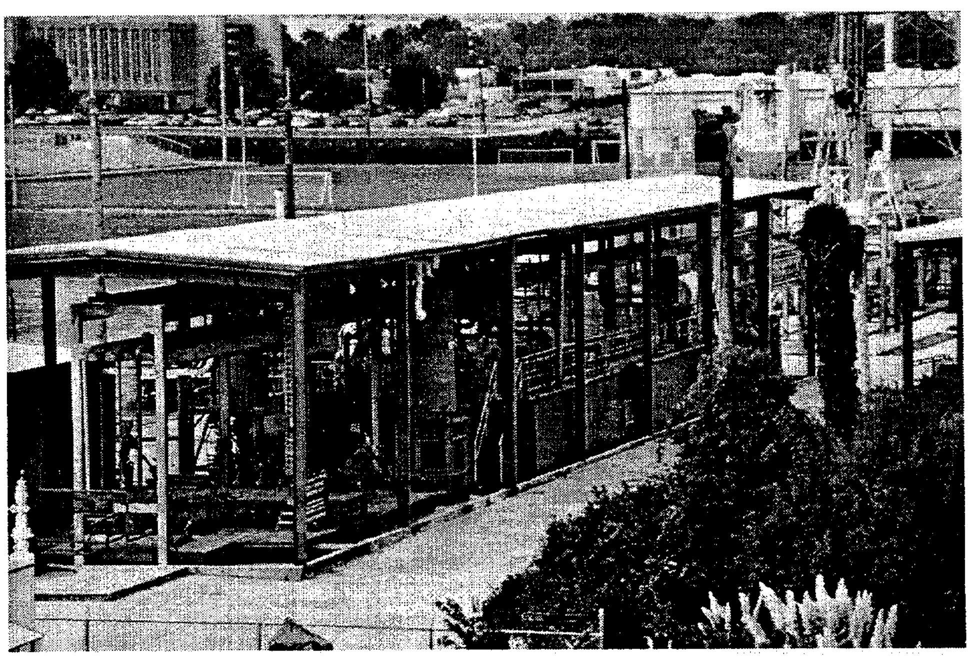

Figure 1 - Recent Photograph of LSU No. 1 Well and Associated Surface Facility

RESEARCH FACILITY IMPROVEMENTS

In 1995, the recompletion of the LSU No. 1 Well was finished as shown in Figure 2. The tie-in of this well was completed shortly after the last MMS Workshop in May, 1995. LSU N0. 1 has been used extensively for both research and training since that time.

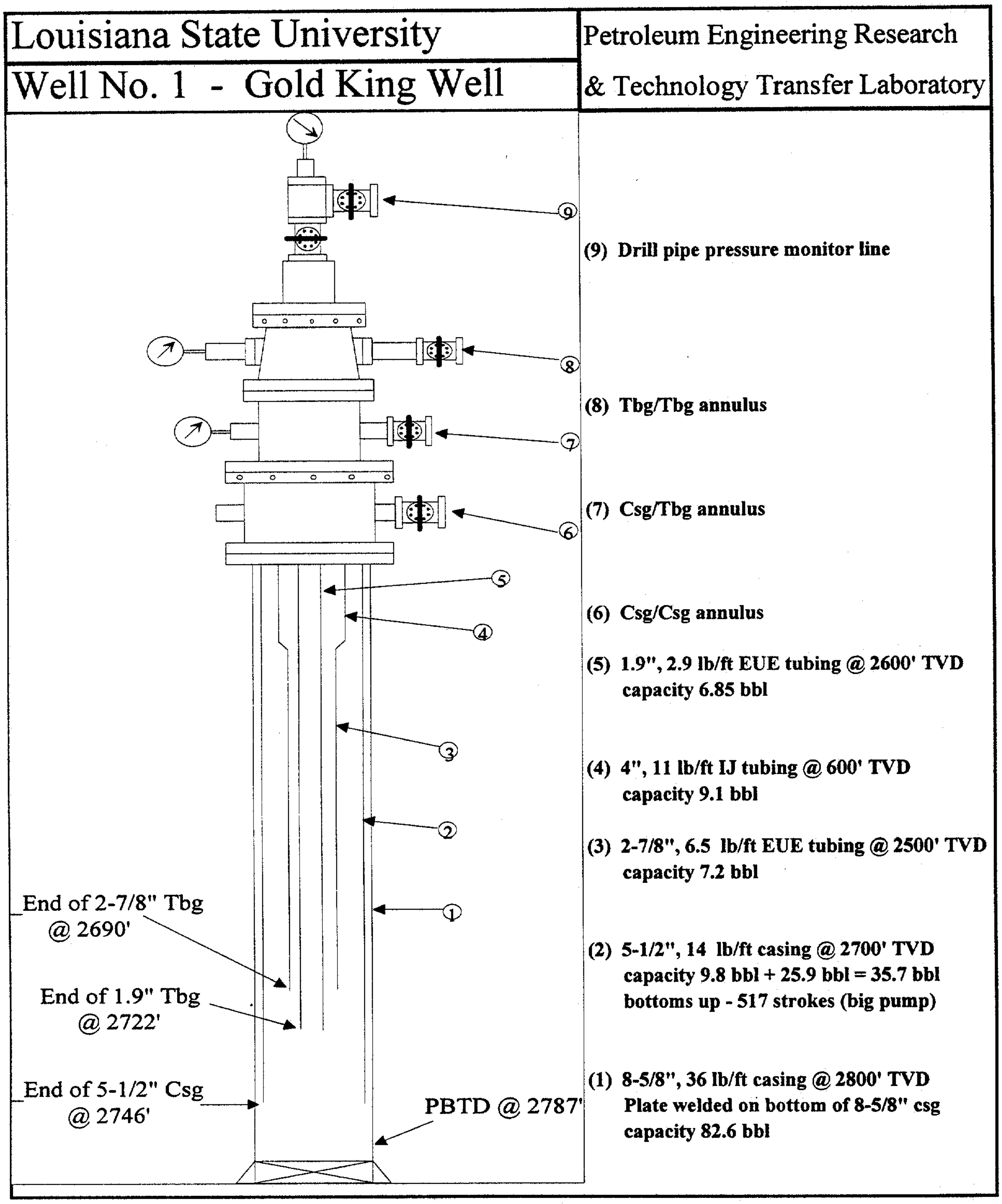

Figure 2 - Schematic of Current Configuration of LSU No. 1

The LSU No. 1 Well is now configured in such a way that we can simulate a variety of different downhole conditions. For example, we pump fluid down the 1.9" by 4" annulus tapered to 2.875" at the bottom, pump gas down the 1.9" tubing, and take returns up the 4 & 2.875" by 5.5" annulus to simulate conditions of lost circulation. As we let the bottom hole pressure increase, an automatic choke on the 5.5" by 8.625" annulus reaches a pre-selected "breakdown" pressure and begins releasing our "fluid loss" back to an isolated mud tank that is not part of the active system being used in the simulation. The automatic choke can be computer controlled to simulate different fracture conditions.

To make it possible to keep the simulated loss returns separate from the active system, SWACO donated an additional 25-bbl gas separator and LSU funds were used to drill and equip an additional liquid seal. The dip legs that provide the liquid seal on the two separators are about 40 ft in length to allow separator pressure to build to 15 psi without gas underflowing to the mud pit. This improves safety and insures that almost all of the gas flows through the flare line where it can be measured. This new arrangement allows us to measure the liquid returns separately. It also allows us to easily switch from using drilling mud to water. A photograph of the dual gas separator system is shown in Figure 3. A photograph showing the liquid seal arrangement is shown in Figure 4.

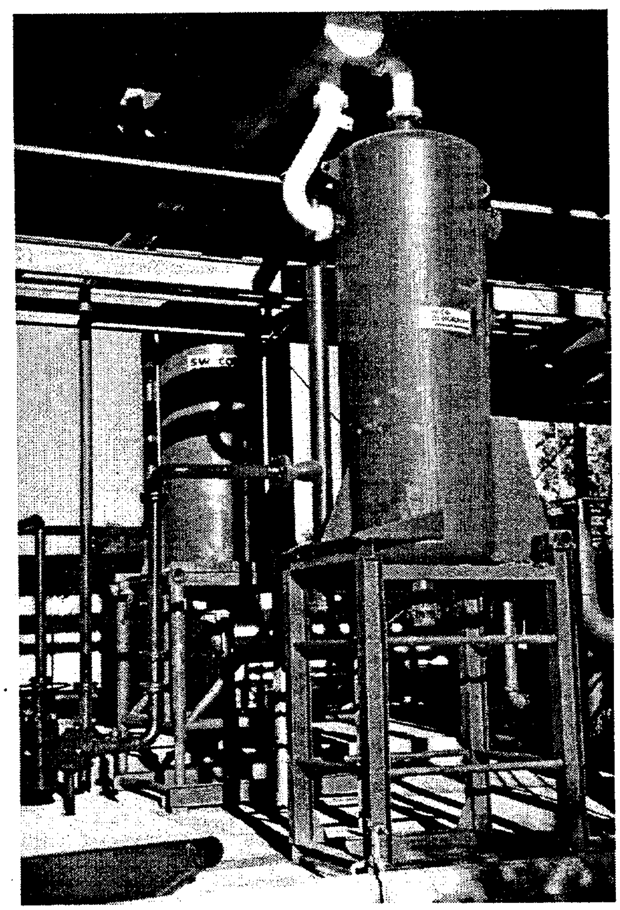

Figure 3 - Photograph of new dual path gas separation system

Figure 4 - Photograph of liquid seal system installed on dual separators

The new compression equipment boosts the pressure of natural gas from the available pipeline pressure of 650 psi to a gas storage well pressure of about 1800 psi. The high pressure gas is then used to simulate threatened blowout events in the LSU No. 1 Well. As gas is used from the system, the gas charging system can continually rebuild the pressure. The compressor is able to charge at a rate of about 165 scf/min to meet our new experimental needs.

The old method for boosting the gas pressure to simulated bottom-hole pressure was to pump mud into the bottom of gas storage wells using triplex cementing pumps. However, this technique is very slow, often requiring a day or two of preparation before a full charge can be developed. Also, only two thirds of the well volumes can be utilized for gas storage, and gas pressure cannot be restored while a threatened blowout experiment is underway. The underground blowout simulations sometimes require a continuous injection of gas at simulated bottom-hole conditions. This continuous injection cannot be sustained with our current system.

A photograph of the new gas compressor is shown in Figure 5. The system will automatically shut down and isolate itself from the system if either the suction or discharge pressure is outside of the normal operating range. Safety relief valves are also installed that will vent gas if a high pressure condition on the suction side of the compressor is experienced.

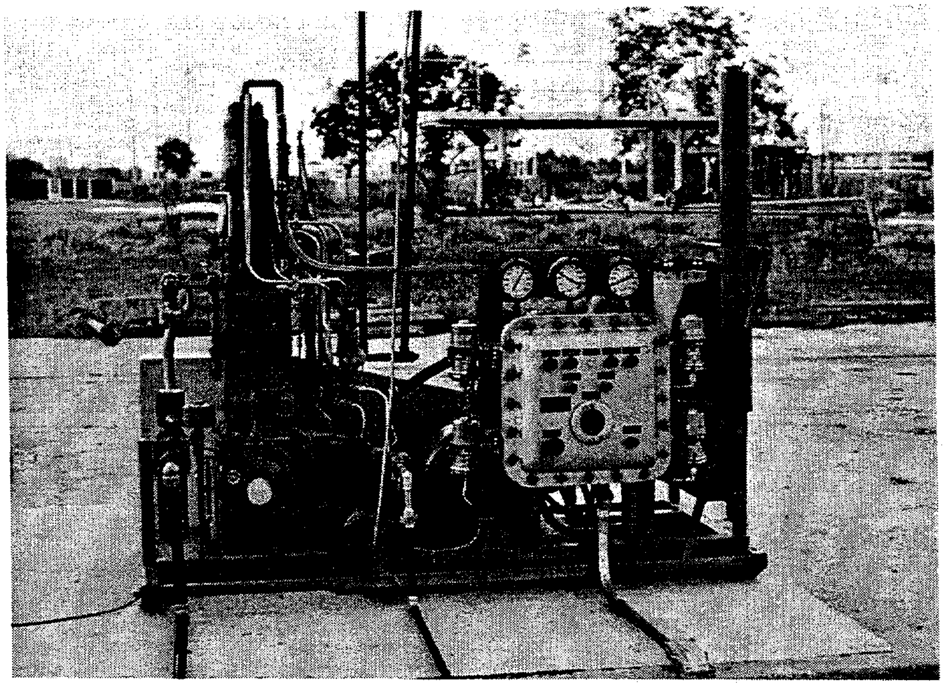

Figure 5 - Photograph of new gas compressor system

Much can be learned about the multiphase flow occurring in a well during well control operations if the gas flow from the well is accurately monitored. This is a difficult task because of the very wide range of gas flow rates seen at various phases of the well control operation. An improved gas measurement system has been installed in the flare line to greatly improve our possible range of measurements. Four different size Daniels orifice meters were installed in parallel on the flare line that now allow gas rates from 1.2 MSCFD to 6,000 MSCFD to be measured exiting the well. The meters greatly simplify the determination of gas flow rate from the pressure and temperature sensors in the meter by providing input to a Daniels flow computer. A schematic of the new arrangement is shown in Figure 6.

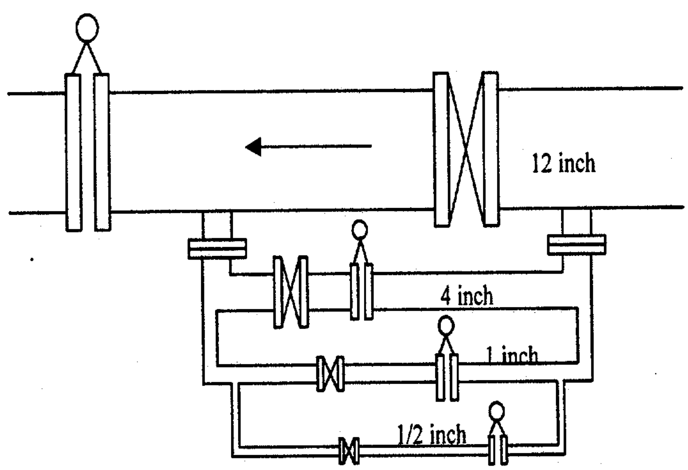

Figure 6 -Schematic of new orifice meter arrangement in flare line

During the past year, one of our triplex pumps began to show signs of excessive wear and needed to be retired. Halliburton has donated a newly rebuilt 4" HT-400 high pressure mud pump (Figure 7) to replace the worn pump of the same size. We are currently installing the remote controls for the new pump. The controls used for the retired pump were of a different design and will have to be modified. Our facility now has two mud pumps, a high volume pump with 6" plungers and a smaller volume pump with 4" plungers. The two pumps will allow us to perform research using rates ranging from 0.5 BPM to about 12 BPM and pressures up to 5000 psig.

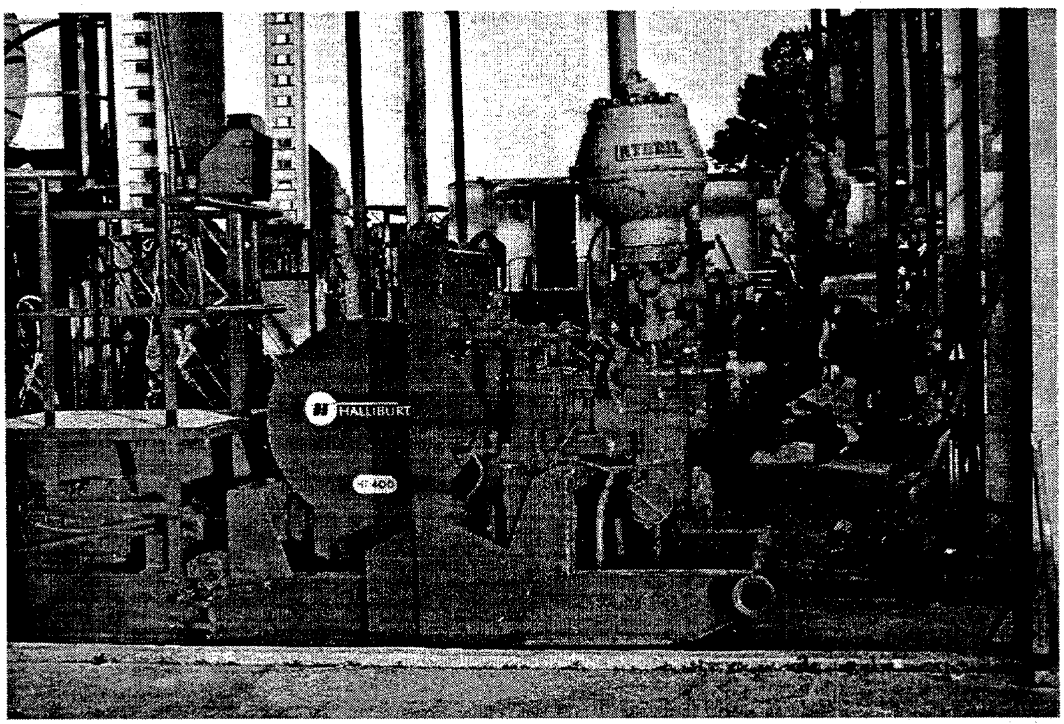

Figure 7 - Photograph of New Triplex Pump

We are in the process of upgrading our data acquisition system and our sensor array. Our DAQ system can now monitor and display up to 32 channels of data, although we currently have provisions for only 14 channels. One new piece of hardware allows us to split the screen display across two monitors, thus allowing us to greatly expand the amount of visual information displayed at one time. This is being used in our study of underground blowouts. Additional and upgraded pressure sensors will allow extremely accurate monitoring of more points of interest. This upgraded data acquisition system is being integrated with our computerized well control system. The data acquisition system has also been used to support the dual-density riser simulations, testing of drill string safety valves, and testing of sealing elements for underbalanced drilling.

TRAINING FACILITIES IMPROVEMENTS

During the past year, several improvements in our training facilities have been planned and are now being implemented. LSU will serve as a Beta test site for new training products being developed by CS, Inc. LSU will also assist in modifying simulation software to improve the quality of the available training and the accuracy of the simulation. Experiments conducted in

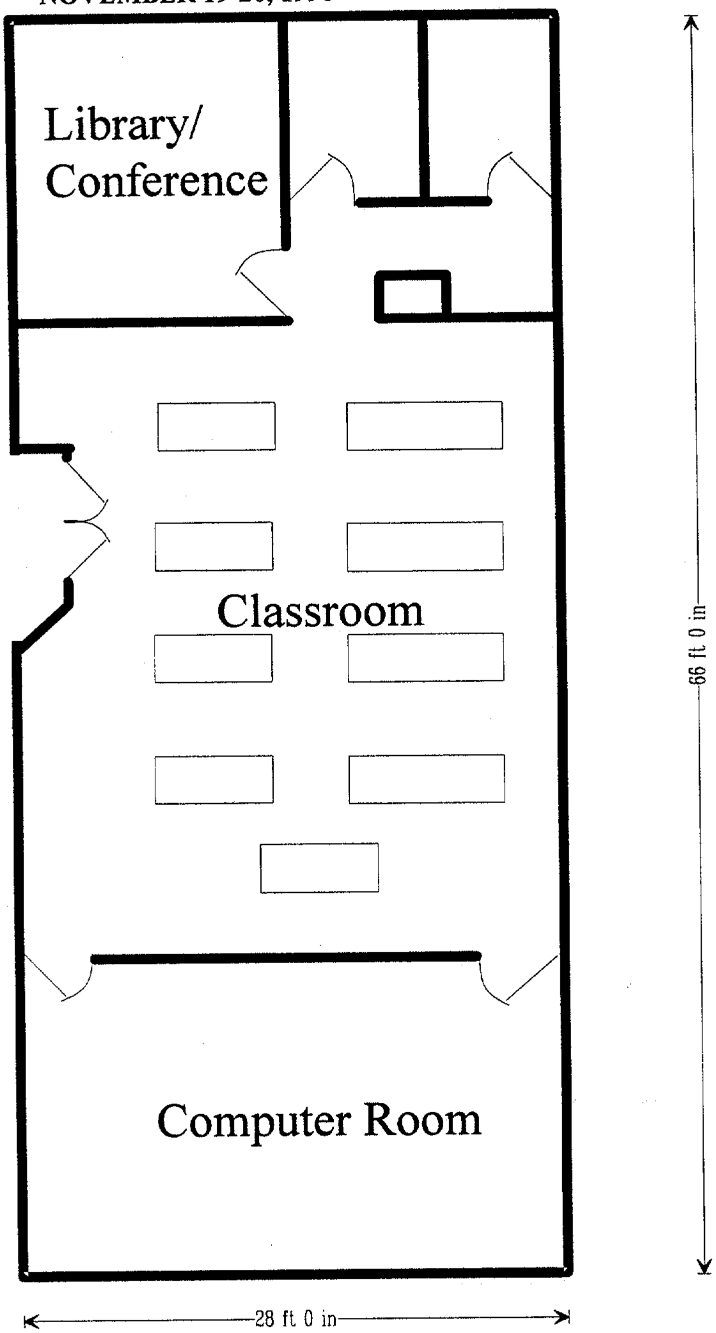

Figure 8 - New Classroom Building

our research and training wells will be used to verify the performance of the simulation software. As part of this project, a new "state-of-the-art" rig floor simulator will be installed in our old classroom building. Delivery of the new simulator is expected by the end of the year.

The classroom space being dedicated to well control simulation is being replaced by a new 1850 sq. ft modular classroom building (Figure 8). The new building includes a main classroom that is about 30% larger than our old one. In addition, the new building has a large computer training room with 5 new computers, a library/conference room, and two bathrooms. The computer room will allow computer-based training modules to be implemented. Computer Simulation, Inc. is making all of their modules available for our training activities. In addition, we will assist in developing new modules. As our database of actual well control events grows, we can imagine individualized training for a student's particular rig type and specialized needs.

The improved training facility will allow a class to be broken into smaller modules for hands-on training exercises. This will allow more individualized training and knowledge level evaluation. While one group performs exercises in our training well, a second group can be working in the simulator room, and a third group can be doing exercises with the computer based training modules, and a fourth group can be doing an exercise on auxiliary well control equipment such as an accumulator system. Each training medium can be used for the type of practice problem that it is best suited for.

The improved training facilities are also being used for industry schools in areas other than well control. We have just completed a one week school on hydraulic fracturing technology for Phillips Petroleum Company. We are planning a second fracturing school for March, 1997. The facility allows hands-on exercises and quality control procedures used with fracturing fluids to be implemented.

Shown below is an example training exercise conducted using the newly configured LSU No. 1 well when pumping down the 1.9-in. tubing and taking returns from the 5.5-in. casing. The student exercise was recorded using the new data acquisition system. Each curve contains over 1500 recorded data entries.

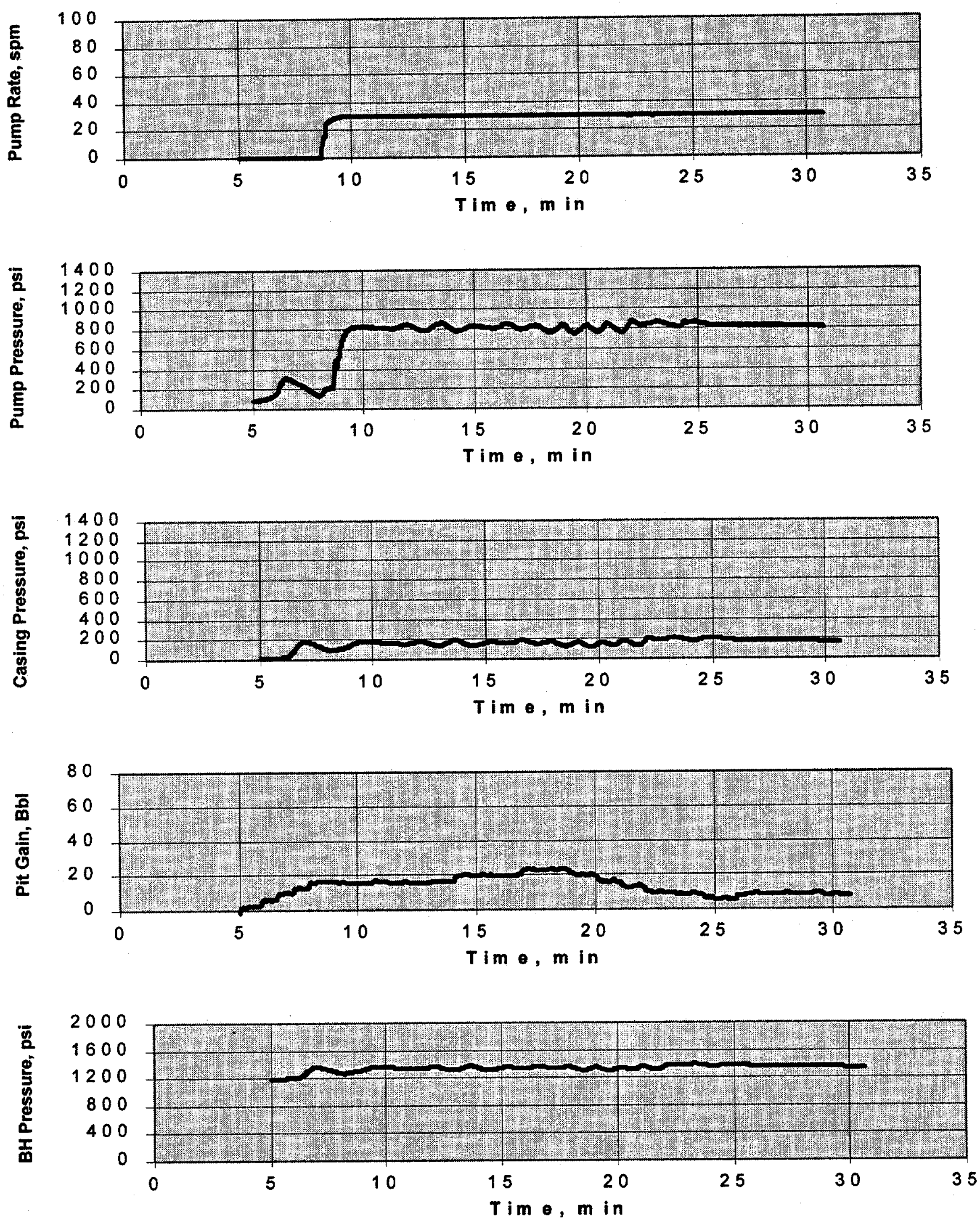

Figure 9 - Example well control exercise conducted using new configuration for LSU No. 1

PREVENTION OF FLOW AFTER CEMENTING OF SURFACE CASING

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OBJECTIVES AND METHOD

The objective of this work is to analyze the present status of technology for preventing and combating early flow of formation fluids after cementing the top section of petroleum wells. The overall aim of this study is to identify emerging standards in dealing with this problem.

The analysis has been made by attempting to answer the following questions:

1. What is our present knowledge about mechanisms of early gas migration?
2. What are the techniques and procedures used in field operations?
3. What is new developments have been made in gas migration technology in view of:
    - analytical support for cement design,
    - new equipment, tools and methods?
4. How typical are reported case histories of flow after cementing in terms of common symptoms and potential for predictive calculations?

The methodology of this study included the following procedures:

- survey of recently published technical literature on the subject,
- analysis of unpublished/confidential industry data,
- site visits and verbal information from industry experts,
- mathematical modeling and analysis of the collected data.

PRESENT STATUS OF KNOWLEDGE

Present understanding of mechanics controlling the flow after cementing recognizes four categories of migration in the annulus:

- early migration through cement slurry,
- early migration through undisplaced mud cake,
- late migration through cement/casing interface,
- late migration through porous cement.

The phenomenon of early migration after cementing concerns cement slurry in its transitional phase between a dense suspension of particles in water and cement slurry initial set. Initial set of cement is defined by ASTM as the time needed to obtain cement punch penetration strength of 50 psi.

The occurrence of flow after cementing is directly caused by the volumetric loss in the cement column and development of Static Gel Strength [5], [16], [18].

Volumetric Change in Setting Cements

Right after cement in place, a continuous process of cement slurry volume reduction begins and ends when cement finally sets [19], [18]. The two main contributions of this volume change are filtration of free water into permeable rock and chemical shrinkage [19],[23]. Both phenomena occur independently and lead to the loss of cement volume.

Cement Fluid Loss

The phenomenon of filtration of water from cement slurry does not occur in the same way as filtration from mud. The reason is that cement free water has to permeate through both cement filter cake and previously developed mud filter cake.

The static fluid loss equation is based on Darcy law, in consistent units it is [1]:

$$q = \frac{A}{\mu} \cdot \frac{\Delta P}{\frac{e_c}{k_c} + \frac{e_m}{k_m}} \quad \text{.......} (1)$$

where:

A – cake area of flow,

μ – water viscosity,

L_c – cement cake length,

L_m – mud cake length,

k_c – cement cake permeability,

k_m – mud cake permeability,

ΔP – pressure differential across cement and mud cake.

e_c- cement cake thickness,

e_m- mud cake thickness.

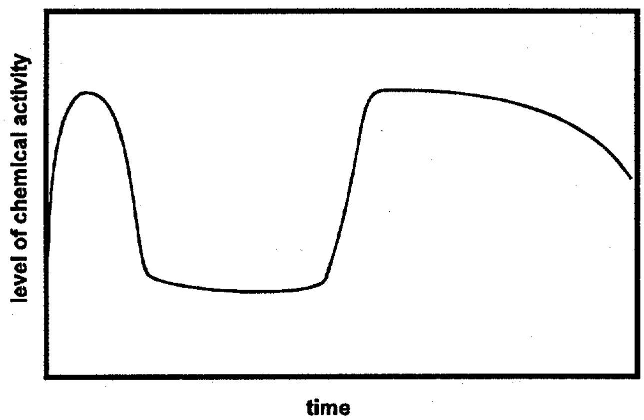
The following conclusions can be drawn based on the above fluid loss equation:

- in the beginning fluid loss will be largest at the bottom of the open-hole section of the bore-hole provided a uniform pore pressure gradient exists,
- as cement column starts losing its hydrostatic pressure due to SGS development, fluid loss tends to be more uniform in the whole open-hole section of the wellbore.

Cement Chemical Shrinkage

Another factor leading to the cement volume reduction is chemical shrinkage. There is much less agreement as to the dynamics, magnitude and effect of this phenomenon on the volume reduction in the critical time of cement setting [7], [1], [3]. Chemical shrinkage is closely related to the rate of chemical reactions leading to cement hydration, which can be traced by monitoring cement temperature during setting. A typical curve of temperature changes in setting cement is shown in Fig. 1.

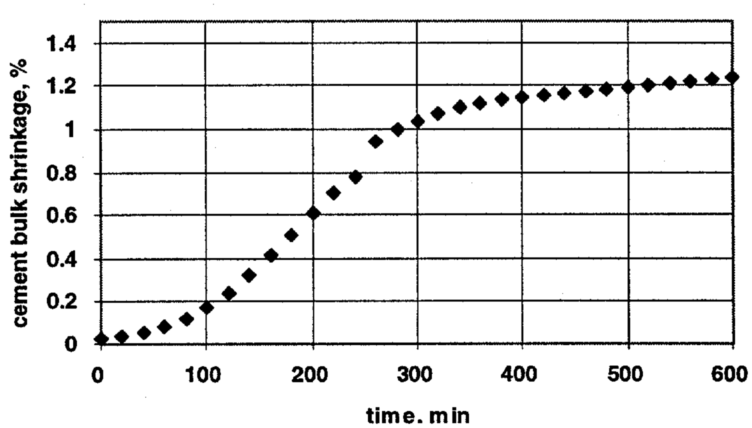
Fig. 1. Degree of chemical activity as indicated by the temperature changes in setting cement.



Within the first several minutes chemical reactions occur very fast. It is followed by a few hours' dormant period when the reactions are almost halted. Then the rate of reactions increases rapidly again until cement finally reaches full bond.

One should distinguish between an external volumetric shrinkage and matrix internal shrinkage. They both comprise total chemical shrinkage which is dependent on cement composition and reaches values between 4 and 6% [1], [3]. A typical cement shrinkage curve is shown in Fig. 2.

Fig. 2. Development of cement bulk shrinkage in time, after [3]



Shrinkage does not reach a value of 1% before 6-7 hours, with a typical value of 0.05% after 4 hours [3], [1]. This may lead to the conclusion that shrinkage is insignificant at the period wherement is fluid enough to let gas flow [3]. Other observations contradict this notion by showing that shrinkage develops when most interstitial water is trapped by chemical or capllary forces, but conductive porosity in the cement exists. Even small shrinkage at that time will result in a significant pressure drop in the water-filled porous space causing pore pressure to drop below water gradient and thus letting gas migrate upwards [13].

Cement Gelation

The combination of cement slurry volume decrease and cement gelation is responsible for fluid migration [19]. Cement slurry has been shown to be a viscoelastic material [53]. Almost immediately after pumping is stopped, cement slurry develops a structure, showing thixotropic behaior [12], [24]. Rheologically, it is characterized by a growing value of Static Gel Strength (SGS). Cment slurry volume reduction causes cement column to move downwards and forces opposing this motion are capable of decreasing cement column hydrostatic pressure significantly [22], .

Cement Porosity

As cement slurry hydrates, it undergoes a phase change from a liquid suspension to a solid body. At a certain stage of hydration an analogy can be made between setting cement and a porous rock [1]. Cement porosity distribution has been studied by Parevaux by mercury porosimetry technique [73]. Samples of cement at various stages of hydration have been obtained, freeze-dried in liquid freon and nitrogen.

The author concluded that free porosity of cement increases when pressure is applied and decreases with temperature. Pore size distribution depends strongly on the stage of hydration. At the time of thickening defined as the time when cement temperature starts to increase above test temperature, free porosity is composed in 50% by macro pores and in 40% by meso pores. After 24 h of hydration, macro porosity completely disappears and free pores are composed of equal volume of meso and micro pores. Parcevaux postulates that cement chemical shrinkage is the only source of free porosity development in cement. Free pores are large (modal diameter 1μm)and well connected at the early stage of hydration. Formation of hydrates caused development of trapped pores. Also, hydrates plug free pores and their internal porosity is very small. Pressure causes the delay of appearance of free pores, temperature reaching over 80°C gives rise to larger pores.

Cement Permeability

The development of cement permeability has been studied by Sutton et al. [9] and Appleby et al.[74]. Sutton has used a U-tube filled with cement and water on top. He pressurized one leg of the tube to 5 psi and constantly withdrew water from the other. The rate of the withdrawal was measured while constantly monitoring pressure differential between the top of the legs.
Cement permeability was computed using the following equation:

$$k = \frac{q_{max} \cdot \mu \cdot D}{4 \cdot A \cdot SGS} \quad \text{...(2)}$$

where:

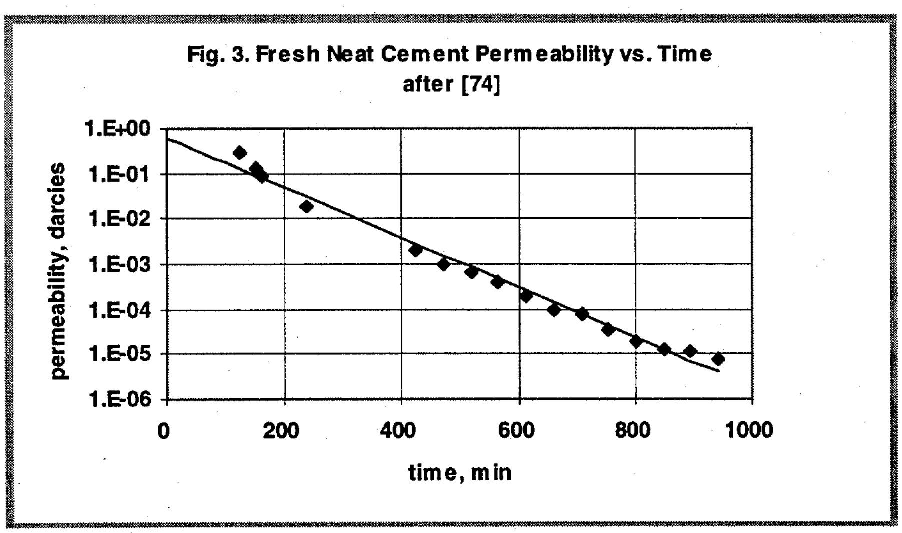
q_{max} -maximum flow rate,

$\cdot\mu$ - fluid viscosity,
D - diameter of the tube,
A - cross sectional area of the tube,
SGS - static gel strength of the cement in the tube.

According to the authors, it is valid to monitor SGS development and permeability at the same time using this procedure. Authors found a strong relationship between slurry permeability and API fluid loss. Generally, early cement permeability ranged from 1000 md to 5 md.

In the experiment, a procedure analogous to measuring fluid loss has been used, so results strongly correlated to API fluid loss should not be surprising. The experiment fails to take into account the effect of pore volume and pore distribution changes in the setting cement. As shown by Appleby, cement slurry consumes water during hydration, also it shrinks. Another possible uncertainty involved in the experimental procedure is that the pressure gadient imposed on the fragile slurry may fractured it, leading to the overestimating of permeability.

Appleby measured setting cement permeability in two different ways. He observed that hydtion causes suction, causing any free fluid on the top of cement to flow into cement body. He represented the force driving water into shrinking cement as an effective sink rate. The matial, on the other hand, has been modeled as a poroelastic body. The author obtained a relationship between rate of pressure decline and rate of strain change as a function of the sink term. Using this equation, he was able to relate the rate of fluid drawn into cement body to cement permeability on one hand and to relate sink rate to cement shrinkage, both bulk and internal, on the other hand. To validate these concept, authors used Sutton's technique with U tube measurement. The results of both experiments are shown below.



The agreement between both methods is good. It proves indirectly that the concept of cement suction is valid. Also, it showed that flow of water through early time cements may be approximated by Darcy's law, while for late time cements the model of poroelastic material should be used. The authors also concluded that effective sink rates follow a pattern similar to the level of chemical aoity in cement.

CURRENT FIELD PRACTICES TO PREVENT FLOW BEHIND CASING

Typical Sequence of Operations

In the areas where there exists a risk of annular fluid flow after cementing every effort must be made in order to minimize the chances of such an occurrence. The probability that an event of annular fluid flow may be controlled is poor and risk associated with salvation operations is high.
Design and execution of a cementing job will be different for shallow and deep water applications. Table below summarizes sequence of operations leading to successful cementing for both shallow water and deep water wells [78], .

Operation/Phase:	Shallow Water Cementing:	Deep Water Cementing:
Mud Design	flat gel strength, low fluid loss, firm, thin filter cake [51]	same as shallow water
Mud Conditioning	to eliminate gels and erode excessive filter cakes [51]	not applicable
Viscous Pills (Sweeping Fluid)	not applicable	remove cuttings from the borehole and provide adequate filter cake, foamed fluids becoming very successful due to their excellent displacement efficiency and density flexibility [78]
Spacer	pumped to separate mud from cement and to wet surface of rock and casing in case of oil base muds [51]	not applicable
Spotting Fluid (Kill Mud)	not applicable	stabilizes the wellbore, recently settable fluids have been designed to provide a settable filter cake, activated by cement slurry [78]

Mud Displacement	turbulent flow regime if possible, minimum contact time 4 min. [51], [59]	usually plug flow
Casing Centralization, Reciprocation and Rotation	all achievable [1], [51], [11]	centralization difficult to achieve, casing cannot be moved
Fluid Density Hierarchy	fluid pumped denser by 10% than fluid displaced [51]	difficult to achieve due to narrow margin between pore pressure and frac gradient [78]
Fluid Frictional Losses Hierarchy	fluid pumped having 20% more frictional losses than fluid displaced [51]	achievable
Cement Free Water and Sedimentation	zero [20]	zero
Cement Filtration	less than 50 ml in API HTHP test, 1000 psi differential pressure [18], [51], [17]	less than 50 ml in API HTHP test, 1000 psi differential pressure, [78]
Thickening Time	cement should start to set from the bottom up immediately after placement, [51], [19], [59]	same as shallow water
Transition Time	minimum [59]	minimum
Rheology	optimized so that frictional pressure losses follow the above hierarchy, ECD must not exceed frac gradient of the formation	difficult to achieve due to narrow margin between pore pressure and frac gradient
Compressive Strength	must be on the order of 500 psi in 24 hr at bottom hole conditions [78]	difficult to achieve at low temperature and for low density cements typically used, must use special cements

Preventive Measures Practiced by Operators

Table below presents present techniques and procedures used by the major operators in the Gulf of Mexico.

Operator:	Special cements used:	Other techniques/operations:
BP [75]	• avoid using special cements on routine basis, • propose use of chemical grouts to plug flowing zones.	• emphasis on casing centralization and good mud/spacer/cement design, • use of turbulators to spin cement and enhance mud displacement efficiency, • recommend drilling with marine risers and driving casing to 2000 ft below mud line, • introduced contingency plans to tackle the problem.
Shell [77]	• salt-saturated cements, • cement substitutes, • compressible cements, • surfactant cements, • slag mix cements.	• focus on good mud displacement.
Phillips Petroleum [77]	• lightweight lead cements: silica fume, colloidal silica.	

Mobil [77]	• lightweight cements with guar, sugar or polymers to control free water.	
Arco [77]	• latex expanding thixotropic cements	• good supervision of job execution
Texaco [77]	• right angle set cements.	• focus on proper displacement: recommend use of centralizers, • proper design of fluid rheology, filtration and pumping conditions, • increasing mud and spacer density above cement column.
Unocal [77]	• right angle set cements, • latex cements, • foamed cements.	proper design of cement job with emphasis on: • low fluid loss, • zero settling, • proper supervision of job execution, • customized spacers and preflushes to maximize mud displacement.
Amoco [77]	• cement is chosen based on the gas migration test results,	• routine use of gas migration test cell.
Conoco [77]	• cements with quick transition time, • avoid retardation of cement.	• emphasis on fluid loss control.

Based on the above table, the following conclusions may be drawn:

1. Operating companies avoid using special cements on a routine basis due to cost. They stress good fluid design, mud displacement and supervision.
2. If a well is drilled in an area known to give severe problems in the past, special cements are used regularly.
3. Only one operating company uses laboratory tests of gas migration in order to screen various cement compositions for the cementing job.

State-of-the-art procedures leading to prevention of flow after cementing can be summarized as follows:

1. Identification of areas with flow problems.
2. Accurate determination of pore pressures, fracturing gradients as well as lithology, often using MWD and LWD.
3. Careful design of mud/spacer/cement systems according to the recommendations outlined above with special attention towards filtration control.
4. Application of special cements designed specifically to perform in wells with flow potential.
5. Use of automated cementing equipment. Its benefits include:
    - elimination of human error,
    - uniform properties of cement slurry,
    - accurate addition and mixing of additives.
6. It should be noted that inaccurate addition and non-uniform distribution of cement additives has been identified as one of the reasons of poor quality of cementing jobs in the past [76].

NEW TECHNOLOGY

New Cement Compositions

The table below summarizes special cements developed to help prevent flow after cementing. New cements are designed to resist at least one of the mechanisms leading to flow afterementing. It may be:

- fluid loss,
- cement slurry internal shrinkage,
- development of porosity and permeability,

development of gel strength and subsequent loss of hydrostatic pressure.

Cement Type:	Mechanism of Action:	Description:	Extent of Application:	Advantages:	Disadvantages:
Compressible Cement [19], [23], [32]	increase compressibility of the slurry	• certain aluminum powder added to generate hydrogen gas in situ after cement placement, • sometimes surfactants are added to prevent coalescence of bubbles and trap gas in stable foam	• the oldest cement used for the last several years, designed specifically to tackle the problem of flow after cementing, • lately used less often	• relatively inexpensive, • may help in cases when moderate problems with flow is expected,	• flammable, • a lot of controversy as to its performance exists, primarily due to possible bubble coalescence and promotion of gas flow, • volume of generated gas in downhole conditions may be marginal
Surface Foamed Cement [60]	• low fluid loss, • high compressibility, • low permeability	foam creates a barrier to gas migration by its high viscosity at low shear rates, traps gas into stable foam by virtue of its low surface tension	widely tested and applied	• recommended in most severe cases of flow, • has a very good performance record in deep water drilling [34], • may be used in a variety of conditions due to its density range	• expensive, • needs special gas handling surface installations, • poor mud displacement characteristics
Thixotropic Cement [29],	• increase of cement body resistance to deformation,	• develops high early gel strength; • additives used: bentonite, various polymers and sulfate salts	• more and more rarely used in the present, peak popularity in the early 80s,	• relatively simple to prepare and use, • relatively inexpensive	• most formulations exhibit high fluid loss, • doubtful effectiveness in the light of the present knowledge, • not recommended in serious flow problems
Expanding Cement [30]	prevents creation of microannulus	• anhydrous calcium sulphonate, • calcium sulphonate lime, or other additives used to obtain up to 0.2% volumetric expansion; • designed to obtain better bond on the cement/formation, cement/casing interface	• several field trials, • presently seldom used	• may help in situations when poor mud removal is the prime cause of annular flow, • relatively inexpensive	• still undergoes the same internal chemical shrinkage and experiences the same hydrostatic and pore pressure decrease
Delayed Gel Cement [33], Right Angle Set Cement (RAS) [54], [49]	modification of gel strength development curve to minimize transition time	• can be either retarded: Delayed Gel, or accelerated: RAS Cement, • various additives used, like certain modified acrylamid polymers to achieve desired characteristics	extent of application depends of the formulation used, most of the additives have not been widely used	• certain additives have a very good record, • good compressive strength characteristics, • retarded cements are especially good for	• some additives are very expensive, • do not perform well in all conditions, • many polymers are not stable in high temperatures

				deep well cementing	• retarded cements usually exhibit high filtrate loss
Impermeable Cement [38], [56], [55], [71], [72]	• bridging of pore throats in cement matrix, • filtration control, • use of very fine cementitious material to minimize porosity and permeability	types of cements used: • styrene-butadiene rubber, • latex, • certain cationic polymers, • microfine cements, made of fly ash, silica fumes or blast furnace slag materials, • salt saturated cements: salt precipitates as water is consumed in hydration, plugging pore throats. Most polymers viscosify water and deposit an impermeable film on hydration products	• latex cements have been extensively used and have good record, • most other cements have been successfully tested but not extensively used, • microfine cements perform well in deep water operations [34]	• most display good rheological properties, low fluid loss and good bonding, • very good perfomance in low temperature, low density [34] applications, • salt cements are inexpensive	• most polymer-based cements and microfine cements are very expensive, up to 10 times of the cost of neat formulation •
Emulsion Cement [70]	• alters cement porosity and permeability, • reduce free water, • trap gas/water into emulsion	• creation of double emulsion: water in oil in water, • elimination of free water by osmotic forces, • exert high interfacial forces to migrating fluid, • decreased permeability to water/gas	tested only in the laboratory	• free water control, • exhibit good rhedogy, • good bond strength	• may have high fluid loss, • difficult to prepare and handle, • emulsion may not be stable in high temperatures, • may be expensive
Surfactant Cement [13], [10]	traps migrating gas into stable foam,	• foaming agent added to create foam when gas starts migrating thus trapping it into stable foam exhibiting high resistance to deformation at low shears	used successfully in the field	• works well in moderate gas flow problems, • relatively inexpensive	• may not work in severe gas flow problems, • will not work in water flow problems

Bottom Hole Pressure Prediction Models

The knowledge of bottom hole pressure during cement setting is one of the keys to successful prevention of gas migration. The first model of pressure dcline originates from the work of Sabins et al. [22], [28] and takes into account the development of Static Gel Strength (SGS). Pressure gradient needed to break gelled cement is given as:

$$\frac{dP}{dl} = \frac{2 \cdot SGS(h,t)}{D_h - D_c} \quad (3)$$

where:

SGS – time and depth dependent slurry Static Gel Strength

D_h – hole diameter

D_c – casing outside diameter

The same pressure gradient is responsible for hydrostatic pressure loss:

$$P_h(h,t) = P_{hi} - P_{SGS} \quad (4)$$

where:

$P_h(h,t)$ – cement column hydrostatic pressure as a function of depth and time

P_{hi} – cement column initial hydrostatic pressure

P_{SGS} – pressure loss due to development of SGS, given by:

$$P_{SGS} = \frac{2}{D_h - D_c} \cdot \int_{l_1}^{l_2} SGS(h,t) \cdot dl \quad (5)$$

The original model takes a simplifying assumption of a homogeneous SGS development, therefore:

$$P_h(h,t) = P_{hi} - \frac{4 \cdot SGS}{D_o - D_i} \cdot h \quad (6)$$

In 1987 Chenevert & Jin [7] published their model taking into account several other factors peirtent to cement behavior after placement. Basic equation used to model pressure loss is given as:

$$\frac{dP}{dh}=\gamma(t)-\frac{4\cdot\tau(\dot{\gamma},t)}{D_o-D_i} \quad \text{.......(7)}$$

where:

$\dot{\gamma}$ – shear rate,

γ – product of cement density and acceleration of gravity given as

$$\gamma=\frac{\gamma_o}{1-S(t)} \quad \text{.......(8)}$$

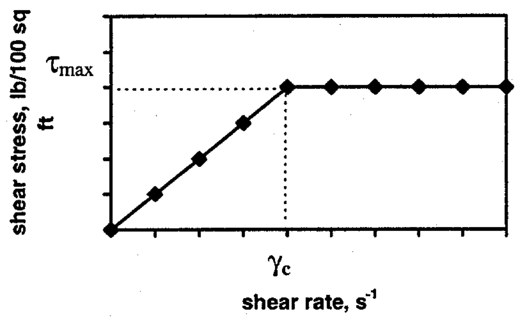
τ – cement shear stress described by the folowing arbitrary function:

$$\tau=c\cdot\dot{\gamma} \qquad for\ \dot{\gamma}<\dot{\gamma}_c \quad \text{.......(9)}$$

$$\tau=\tau_{max} \qquad for\ \dot{\gamma}\geq\dot{\gamma}_c \quad \text{.......(10)}$$

The above rheological relationship can be visualized in the following graph:

Fig. 4. Simple elastic-perfect plastic body rheology, after [7]



Accurate modeling of cement column behavior relies on the quality of experimental data that can be obtained for relation (8), (9) and (10). Equation (8) requires bulk cement volume change with respect to time. This has been adopted from previous work of the authors. The values authors obtained- ca. 4% of the initial volume- have been criticized by others. Indeed, most scientists report bulk volume shrinkage not to exceed 1% up to 10 hrs into setting. In oder to fully characterize the material using the above rheological model, coordinates of only one point are needed (τ_{max}, $\dot{\gamma}$).

Cement filtration has been included using the following relationship:

$$V_f = K\cdot\sqrt{t} \quad \text{.......(11)}$$

The value of constant K has been adopted for previous experiments.
The model works as follows:

1. For each time step , total displacement is obtained from filtration and bulk volume shrinkage for each depth h.
2. Using wellbore geometry, displacements are converted to shear rates.
3. Using the relationship $\tau=f(\dot{\gamma})$, shear stress for each shear rate is obtained.

4. Pressure at each depth and time is computed using the equation (7).

Although the model is simplistic in many ways, e.g. stress vs. strain relationship, uniformlfiation, it produced good results. The model showed that prediction of downhole pressure is possible.

In 1991 another pressure prediction model has been published [69]. SGS development was modeled using the following exponential relationship:

$$SGS(t) = SGS_{to} \cdot e^{\frac{t}{T_r}} \quad \text{......(12)}$$

where:

SGS_{to} – initial SGS value,

t – time,

T_r – characteristic retardation time constant.

SGS values have been measured using vane geometry. This method shows superior accuracy for low shear-rate measurements for fluids exhibiting yield points [66], [57], [52], [39]
, [67], [68]. Shrinkage has been modeled using the following equation:

$$\frac{dS}{dt} = \frac{S_\infty}{\Delta T_s \cdot \sqrt{\pi}} \cdot exp\left\{ -\left(\frac{(t - T_s)}{\Delta T_s} \right)^2 \right\} \quad \text{......(13)}$$

where:

S_∞ – total shrinkage,

ΔT_s, T_s – parameters.

Shear stress was obtained using a similar approach to Chenevert's.

Fluid loss was found from Darcy's law in the presence of both mud cake and cement cake:

$$v_{fl} = \frac{\Delta P(z,t)}{\mu \cdot \left(\frac{e_m}{k_m} + \frac{e_c(z,t)}{k_c} \right)} \quad \text{......(14)}$$

Notation as in eq. (1)
Density change due to volumetric loss is given as:

$$\rho = \frac{\rho_o}{1 - S(t)} \cdot (1 + cP) \quad \text{......(15)}$$

where:

ρ_o – initial cement density,

c – cement column compressibility.
Two conservation equations are used:

$$\frac{\delta\rho}{\delta t}=\frac{\delta(\rho v)}{\delta z}+\frac{4\rho_{fl}\cdot D_o}{D_o^2-D_i^2}\cdot v_{fl}(z,t) \qquad (15a)$$

where:

ρ – cement density,

ρ_{fl} – filtrate density,

z – depth,

D_o, D_i – wellbore and casing diameter, respectively,

v_{fl} – fitrate velocity.

The second equation is identical with eq. (7).

The authors observed that if the left hand term in the equation (15) is greater than rate of volume change in the slurry, stress in the column switches from positive to negative values. This means that an upward expansion of the slurry may occur due to its compressibility if SGS does not prohibit this. If this finding could be confirmed, it would be another possible mechanism of tensile rather than compressive forces acting on late cement. This mechanisms would cause a further reduction of pore pressure in the cement slurry. Other findings are:

- top cement displacement due to fluid loss for retarded cements (latex cement) may be as high as 30 ft,
- pressure transmission due to slurry permeability may be an important mechanism, especially in shallow wells; characteristic propagation time for pressure wave in cement may be equal to 23 min for a 300 ft column of cement.

In 1993 Prohaska et al. [37] published a model which is a refinement of the above model. He described SGS development as a function of shearing time, pressure and time as additional variables.
The same author developed another model which is a further refinement of his earlier work [47]. He introduced the concept of critical distance, which is the distance from the top of the migrating gas to the level where gas pressure is completely attenuated by SGS. Within the volume limited by the critical distance, gas pressurizes the whole slurry. Any cement volume redution within this volume will therefore be replaced by migrating gas. Internal shrinkage and filtration are the only sources of volume loss within the critical distance.

In this model, gas percolates as bubbles. Critical bubble size is estimated using bubble detachment mechanism. SGS is the only opposing force preventing detached gas bubble from moving upwards. The authors noticed that when SGS reached the value of 600 lbf/100 sq. ft, there was a piston-like displacement of cement by gas. This observation suggests that a very high gas pressure would be necessary for gas to flow in a slurry that has SGS value over this critical value. Contrary to it, most gas flow events occur at least 2 hrs after CIP, i.e. while SGS has a value of the same order. Also, gas test cells confirm this behavior.
Sabins published results of his modeling in 1994 [26]. He assumed that initial set is the ultimate criterion for cement to resist gas migration. He observed that at this point SGS reaches the value of 2000 lb./100 sq. ft.

He related internal volume reduction to SGS development. Other variables used in his model are:

- fluid loss described as a function of time of fluid loss from cement and mud,
- cement permeability, described as a function of SGS,

The author proposed two equations to describe pressure drop vs. time: Darcy's equation and eq. (3). His model works as follows:

- SGS vs. time is obtained using a modified consistometer,
- volume change due to internal shrinkage and filtration is estimated,
- at each step pressure loss is calculated using both equations,
- if pressure loss obtained from Darcy's law is greater that that obtained form SGS, the second value is used to compute actual pressure loss, in this case cement column moves downward,
- otherwise pressure loss from Darcy's law is used.

The author concluded that according to the model, fluid loss, SGS, and overbalance pressure affect gas migration the most. Cement permeability on the other hand, has been found not to affect the problem significantly.

The model should work well for early cements. It appears, however, that such mechanisms of pressure loss in late cements as pore pressure decline due to internal shrinkage as well as possible expansion due to tensile rather than compressive forces acting on cement body have not been taken into account in this model. Also, the author did not attempt to model the process of gas migration. Besides, cement permeability should be related to filtrate volume, as water deficiency may result in cement dehydration and in effect, pores will not be plugged with hydration products.

New Model of Hydrostatic Pressure Loss

The model of pressure drop developed for this study assumes that relationship given by the equation (7) holds. The effect of density change on hydrostatic pressure is assumed to be negligible as explained during reporting on Chenevert's model. Filtration during early phase of pressure loss is acting so as to promote shear in the cement body. Volume of water lost to formation due to filtration is given by eq. (11). Column movement due to this volume loss is:

$$\Delta z = \frac{4 \cdot \pi \cdot D_o \cdot z \cdot C \cdot \sqrt{t}}{\pi \cdot (D_o^2 - D_i^2)} \quad \text{......(16)}$$

or

$$v_z = \frac{d(\Delta z)}{dt} = \frac{2 \cdot D_o \cdot z \cdot C}{(D_o^2 - D_i^2) \cdot \sqrt{t}} \quad \text{......(17)}$$

Eq. (17) relates velocity of cement column movement due to fluid loss to time and wellbore geometry. This velocity can be equated to the linear velocity for a Bingham plastic fluid.

In case of low shear rates such a relationship is:

$$v_z = \frac{(R_o - R_i)^2}{12 \cdot \mu_p(t)} \cdot \left(\frac{dP}{dz}\right) - \frac{R_o - R_i}{4 \cdot \mu_p(t)} \cdot \tau_y(t) + \frac{[\tau_y(t)]^3}{3 \cdot \mu_p(t) \cdot (R_o - R_i)} \cdot \frac{1}{\left(\frac{dP}{dz}\right)^2} \quad \text{.........................(18)}$$

where:

$\mu_p(t)$ – time dependent plastic viscosity,

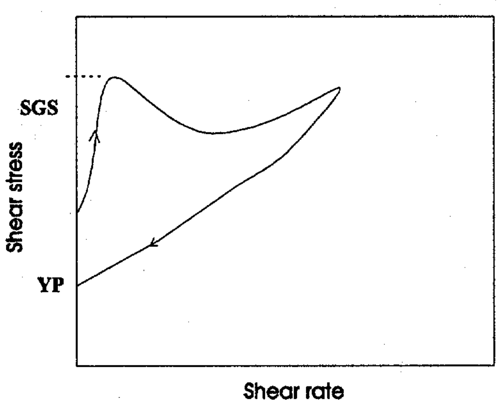
$\tau_y(t)$ – time dependent yield point of the slurry,

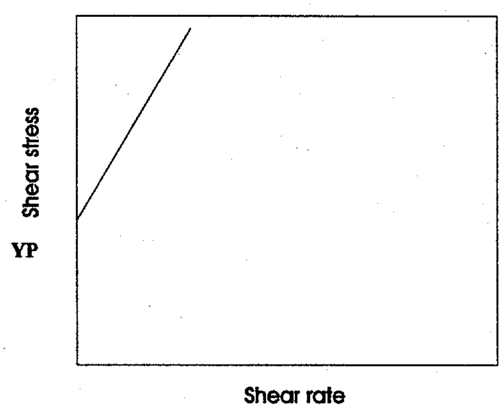
$\left(\frac{dP}{dz}\right)$ – frictional pressure losses gradient.

shear stress at the wall is given as:

$$\tau_w(t) = \frac{R_o - R_i}{2} \cdot \left(\frac{dP}{dz}\right) \quad \text{...(19)}$$

The equation above models low shear rheology. Actual cement rheology has been found to be as seen in the figure on the left [12]. This is approximated by the figure on the right.





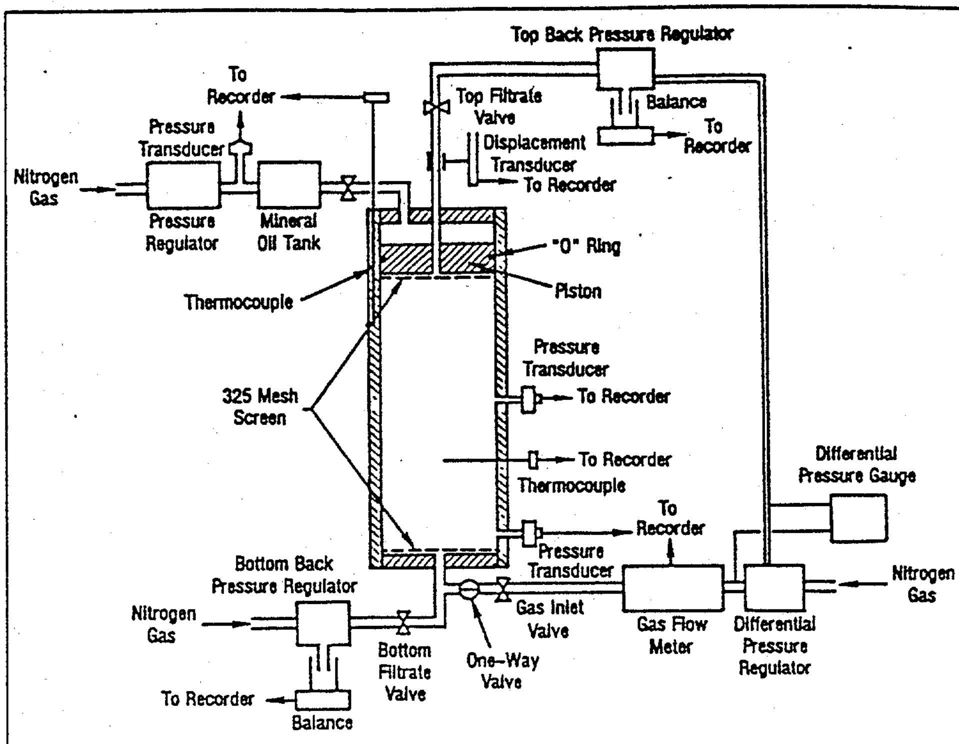
Prediction of cement column pressure based on the development of gel strength is accurate up to the point when the state of cement changes from a suspension of fine particles in water to a porous, self-supporting plastic body [74]. At this point cement behavior must be described with terms used for porous rocks, i.e. porosity, permeability, and tensile/compressive forces acting on the cement matrix. Pore pressure of late cement is influenced by internal volume changes caused by hydration as well as stresses developed by chemical reactions leading to structural changes of the material. At present we cannot tackle the problem of the dual nature of hydrating cement effectively. An example of successful modeling of cement permeability using two models reflecting this dualism is given by Appleby's experiment leading to an estimation of permeability seen in Fig. 3.

Future work could emulate this approach, where parameters characterizing cement slurry over the whole transition time are determined using models for both fresh and late cements. Another approach would be to develop a mechanical model which would be valid over the entire range of cement transition. The broad range of applicability of viscoelasticity could potentially lead to the development of such a model.

Another relationship that must be examined is that between fluid loss and permeability. How does fluid loss affect the development of permeability in cement? Finally, changes in cement matrix stress and how they affect pore pressure need to be addressed.

Laboratory Gas Migration Testing of Cement

An apparatus suitable to simulate downhole phenomena leading to gas migration was first built by Cheung and Beirute in 1982 [6]. It was further modified in 1989 [15]. Since then a number of similar devices have been assembled and used [48], [50], [71], [38].
The modified apparatus designed by Cheung and Beirute is shown below.



Gas-flow cell.

A detailed description of the design and operation of the assembly can be found in [6] and [15]. It can be summarized as follows:

- the apparatus is capable of simulating hydrostatic pressure of the cement column as well as the loss of pressure,
- it also can simulate a high pressure gas zone (or offending zone) as well as a low pressure zone, or surface conditions,
- fluid loss occures both from the top and bottom of the cell,
- a scale-down method can provide a means of simulating actual wellbore conditions.

The scale-down equation is:

$$P_{1c} = \sqrt{P_{2c}^{\ 2} - \frac{L_c}{L_w} \cdot \left(P_{2w}^{\ 2} - P_{1w}^{\ 2}\right)} \quad \text{...(20)}$$

where:

P_{1c}, P_{2c} – pressures at the bottom and top of the gas test cell, respectively,

P_{1w}, P_{2w} – pressure of the low pressure zone and high pressure zone, respectively,

L_c – length of test cell,

L_w – distance between the two zones.

Thanks to it's design, the gas migration test cell is capable of simulating hydration close to actual conditions. One of the few shortcomings of the cell is the ratio of the fluid loss area to the volume from which fluid loss occurs. For a $14^3/_4''$ by $10\,^3/_4''$ annulus this ratio is:

$$\frac{A}{V} = \frac{\pi \cdot 14.75}{0.25 \cdot \pi \cdot \left(14.75^{2-} - 10.75^2\right)} = 0.58$$

The same ratio for the test cell is:

$$\frac{A}{V} = \frac{2 \cdot 0.25 \cdot \pi \cdot 3^2}{0.25 \cdot \pi \cdot 3^2 \cdot 10} = 0.2$$

Theoretically, there will be approximately 3 times more fluid loss from the wellbore than from the test cell, provided all other conditions are the same.

Authors recommend the use of an unrealistically high pressure gradient for the test. The value of the pressure differential across the gas cell will frequently exceed 40 psi. The following calculations have been made to compare gas cell results with typical pore pressure and fracture gradient values found in a typical wellbore in the Gulf of Mexico. Three different scenarios have been assumed: flow of gas from the bottom of the well to a low pressure formation in the middle of the open section of the well; flow of gas from the bottom of the well to the conductor casing shoe; and flow of gas from the bottom of the well to the surface.

Calculation of the maximum pressure differential for gas flow test apparatus					
Case 1		**Case 2**		**Case 3**	
flow between 2 strata in the open hole section of the well		flow between a zone at the bottom and conductor casing shoe		flow from a zone at the bottom up to the surface	
zone 1:		**zone 1:**		**zone 1:**	
depth= 4015 ft	pressure 1983 psi	depth= 4015 ft	pressure 1983.4 psi	depth= 4015 ft	pressure 1983 psi
zone 2:		**zone 2:**		**surface**	
depth= 2675 ft	pressure 1321 psi	depth= 1335 ft	pressure 763.62 psi	depth= 0 ft	pressure 0 psi
Pressure differential: **1.0 psi**		**Pressure differential:** **0.8 psi**		**Pressure differential:** **0.6 psi**	

The worst scenario, i.e. flow between 2 zones (Case 1) should be used in the test.

The above calculations show that accurate scaling down would require the application of very small pressure differentials.

Although the test cell is a very good tool to screen cements, the unavoidable consequence of the use of a short column of cement has to be taken into account. It appears that the unique combination of mechanisms having an impact in long columns of cement is impossible to simulate in short columns. These effects may indeed be the reason why a very small gas pressure gradient is sufficient to initiate flow. Nevertheless, if a certain cement composition passes such a severe test, it should be a good indication of its downhole performance.

As mentioned above, there are several other designs more or less resembling the original. It is worth mentioning two. The first, designed in the late 1980s, [38] can be rotated around its horizontal axis so that simulation of an inclined well can be achieved. Gas is detected in the upper portion as well as at the side walls of the cell.

The second cell [71] is designed to operate at much lower pressures. Nitrogen pressure is approx10 psi, confining pressure is 9.4 psi, so the differential across the cell is only 0.6 psi as compared to 20 up to 40 psi across Cheung's cell. Also, there is no differentiation between the pore and overburden pressure in this cell. Despite these seemingly mild conditions, the authors found that very few cements turned out to be fully gas tight.

Gas migration testers have been known in the industry for the last several years. Four different centers where gas migration testers similar to Cheung and Beirute's design have been identified [79], [76]. Unfortunately, every location uses different testing conditions. Most often hydrostatic (overburden) pressure is kept constant during the test at 1000 psi, gas pressure is 400 psi and top back valve pressure (low pressure zone) is 100 psi. It is vital that a standard for performing these tests is established so that tests made in various centers could be comparable.

A survey made among operating and service companies revealed that only one operator routinely performs gas migration tests. Others in the industry performed these tests only for new formulations.

The modified method of cement slurry testing proposed by Cheung and Beirute in 1989, although having some inherent shortcomings, appears to be the best predictor of cement performance. It is highly recommended, that gas migration tests be incorporated into the design of a slurry for a particular well. Knowledge of gas zone pressure and depth should be used in the scale-down procedure. If this information cannot be obtained a worst case scenario should be assumed as shown in the example in the next chapter. As mentioned above, due to the cell's shortcomings, computed pressure gradients should be increased to reflect that fact. Further study is needed to establish an optimum multiplying coefficient and test procedures.

A standard report from the gas migration test should include at least the following information:
- cement formulation,
- testing conditions,
- time test started and ended,
- when, if at all, gas broke in.

The following conclusions can be drawn from general observations made from performing these tests [76], [79]:
- cements exhibiting high filtration always fail the test,
- low filtration does not guarantee gas tightness, other mechanisms like pore throats plugging, control this property.

Mechanical methods of preventing flow after cementing

One of the most promising methods for the prevention of fluid flow after cementing is cement slurry vibration. It has been shown both in the laboratory [40], [53] and in a field test that periodic vibrations of cement restore it's hydrostatic pressure [31], [].

An overview of recent patents concerning various methods of vibrating either the casing or the cement slurry directly are presented below:

Patent granted to:	Description of the apparatus	Extent of use
SOLUM OIL TOOL 1971 [42]	attached to the drill pipe, when pipe is rotated, it repeatedly strikes against the casing	Used mostly for gravel pack compaction, vibration may be applied only when cement is pumped
EXXON 1981 [43]	vibration started after pumping, vaious methods proposed: hydraulic jars, explosives, adapted geophysical vibrator	Laboratory experiments using oscillatory viscometer as well as a short column filled with cement both confirmed that vibrating results in restoring hydrostatic pressure.
EXXON 1985 [61]	oscillation of drilling mud or preflush to remove mud cake and break the gel near the walls	field tests showed that mud displacement efficiency increased from 65% to 90%
A. Bodine, 1987 [44]	sonic oscillator coupled to the casing collar during cement placement and curing	?
R.E. Rankin, 1992 [41]	vibrating element mounted near the bottom, an eccentric element periodcally strikes against casing when fluid is pumped through the pipe	works only during pumping
EXXON, 1992 [45]	application of pressure pulses to liquid-filled casing interior after cement placement	?
J. Haberman, Texaco, 1995 [46]	application of pressure pulses to the annulus after cement placement.	Field trial

Other mechanical and physical techniques used to prevent gas migration include:

- External casing packers : by inflation, they seal the annulus and therefore prevent percolation of gas. However, these devices cannot be used against soft formations; sometimes they can hinder the transmittance of hydrostatic pressure, thus exacerbating the prblem [21].
- Annular back pressure: application of pressure at the top of the cement column can, indeed, help prevent gas migration [21]. It can also lead to formation fractring, which can develop into cratering. In 1982 Cooke published results of a field trial involving the application of pressure to the annulus with the intention of restoring hydrostatic pressure [25], [27]. It involved periodic applications of pressure to the annulus. Pressure sensors atached to the casing prior to running it into the wellbore showed pressure restoration each time pressure was applied. However response to the pressure in the later period of cement hydration was observed only from those sensors which were in the shallower portion of the well. The author tried to maintain the pressure in the annulus in order to compensate for the pressure loss due to cement gelation. This effort, however, has been unsuccessful.
- Reduction of cement column height: in the presence of gas migration problems, cement column should be as short as possible, remaining column should be filled with spacer with required density

[21]. This method can only be used when there is no need for sealing the whole bore hole with cement and required back pressure can be achieved with a relatively short cement column.

- Low rate pipe movement after cement job: field experiment has shown that reciprocation as well as rotation of casing after cement in place can successfully help prevent pressure reduction in the setting cement [11]. The mechanism of it is that by casing movement, a thin fluidized layer near casing is created which prevents cement from adhering to the casing. Thus cement cannot support itself against the casing in the transition time while losing its volume. It can only stick to the bore hole walls. Cement pressure reduction should therefore be prevented by some 50%. The rate of casing movement is slow enough not to disturb cement farther from the casing. Experiments show that as long as casing is moved, cement gel strength is low. Once movement is stopped, static gel strength builds very fast to values high enough so as to prevent gas from migration.
- Recently, a new method of prevention of flow after cementing has been introduced. Involves periodic application of pressure pulses to the annulus after cement placement. Field trial showed promising results [63].

ANALYSIS OF CASE HISTORIES

Sixteen case histories of flow after cementing of surface casing have been presented at the last MMS/LSU workshop. Typical sequence of events leading to the gas flow can be summarized as:

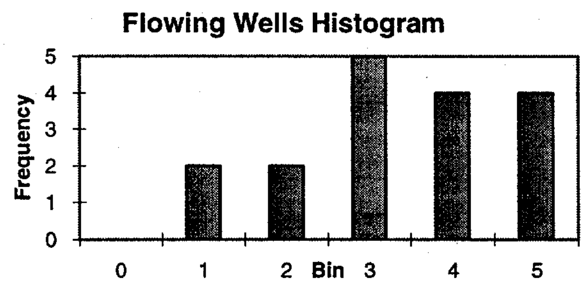
1. Cement is pumped and displaced successfully, the job appears to proceed without problems.
2. After a few hours of WOC diverter/BOP stack is nippled down, the well starts to flow.
3. Diverter is nippled up again, the well is diverter in an attempt to control the flow.
4. Even if diverter does not fail, the well is flowing and is becoming more and more and difficult to control.
5. Various means of restoring control over the well are attempted: circulation of heavy mud through tubing into the annulus, diverting the well, closing the well.
6. In case of severe flow, the rig is evacuated.
7. Sometimes the well can bridge after a few hours/days.
8. If the well is salvaged, it is thanks more to favorable circumstances than successful operation.

In order to analyze past incidents of flow, gas Flow Potential Factors for the sixteen case histories have been computed. Also, data on several wells where flow did not occur have been completed in order to compare both groups and try to find a method to predict flow problems. The summary of the results of this analysis, which had been presented during the latest MMS/LSU workshop is given below.

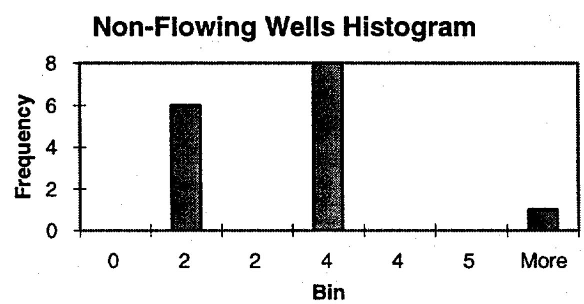
	FLOWING WELLS		NON-FLOWING WELLS
	Flow observed on surface	FPF	FPF
	hrs	d'less	d'less
	?	0.9	3.4
	?	4.5	2
	?	2.6	2.8
	5.5	4.1	1.7
	10.5	1.2	1.9
	3.5	3.1	1.9
	?	2.2	3.3
	?	1.0	2.7
	5.5	3.8	1.8
	2.3	2.8	1
	?	3.0	3.3
	8.0	2.7	3
	7.0	1.5	3.7
	6.0	4.3	3
	2.5	3.5	
	5.5	4.7	
Average:	**5.6**	**2.9**	**2.7**

In order to check the hypothesis that mean values of FPF are of no difference, statistical analysis of the data has been performed, its results are presented in the following table:

Flowing Wells	
Mean	2.9
Standard Deviation	1.2
Confidence Level(95%)	0.6
95% Confidence Interval	2.3 to 3.5



Non-Flowing Wells	
Mean	2.7
Standard Deviation	1.0
Confidence Level(95.0%)	0.6
95% Confidence Interval	2.1 to 3.3



Confidence intervals for the flowing and non-flowing wells are almost the same. The difference between FPF for both cases is therefore insignificant.
In the first part of the analysis of the case histories this problem of the lack of differentiation between flowing and non-flowing wells will be addressed .First we need to examine the Flow Potential Factor itself.

Flow Potential Factor as a predictive tool has been proposed in 1984. The concept is based on the pressure reduction caused by the development of Static Gel Strength in the presence ofement volume reduction. The critical condition for gas entrance is the equality of gas formation pressure and cement column hydrostatic pressure:

$$P_h(h,t) = P_{gas} = P_{hi} - P_{SGS} \quad \text{.......(21)}$$

The critical condition for equality of pressures can expressed as:

$$1 = \frac{P_{SGS}}{P_{hi} - P_{gas}} \quad \text{.......(22)}$$

A number of laboratory experiments with injecting gas into a column of setting cement have been performed in order to obtain a minimum SGS value at which gas will not flow through cement. Detailed description of the experimental procedure can be found in [2], [22]. The expeiments have shown that cement which develops the Static Gel Strength value of 500 lb. per 100q. ft is virtually impermeable to gas percolation. Pressure loss equivalent to this SGS value was called Maximum Pressure Reduction (MPR). In field units eqn. (3) is:

$$\Delta P = SGS \cdot \frac{L}{300 \cdot D} \quad \text{.......(3')}$$

and Maximum Pressure Reduction is:

$$MPR = \frac{500}{300} \cdot \frac{L}{D} = 1.67 \cdot \frac{L}{D} \quad \text{.......(23)}$$

Flow Potential Factor (FPF) is defined as the ratio of the Maximum Pressure Restriction to initial Over Balance Pressure (OBP):

$$FPF = \frac{MPR}{OBP} \quad \text{.......(24)}$$

where initial Over Balance Pressure is defined as the initial cement column hydrostatic prsure minus the gas zone pressure.

FPF concept is based on the premise that gas percolation involves the breakage of cement slurry structure, i.e. percolating gas bubbles need to overcome the yield point of the slurry. In the light of the present knowledge, this assumption has to be refuted [6], [8], [13], [26]. Another argument against FPF is that for a typical non-retarded slurry, SGS reaches the crital value no later than 3hrs after CIP. Most occurrences of gas flow were reported to hppen well after 3 hrs.

Other methods of analysis must be found. There are two additional indices introduced as tools to predict flow problems. Slurry Response Number concept relies on the observation that cements which exhibit low fluid loss and short transition time generally tend to exhibit good gas migration control [35], [36], [58]. It can be expressed it terms of rate of increase of SGS and fluid loss as [9]:

$$N_{SG} = \frac{\frac{d(SGS)}{dt}}{(SGS)_x}$$

$$N_{FL} = \frac{\frac{d\rho}{dt}}{\frac{V}{A}}$$

$$SRN = \frac{N_{SG}}{N_{FL}}$$

where:

N_{SG} – static gel strength number

N_{FL} – fluid loss number

SRN – Slurry Re sponse Number

SRN cannot be a good predictor of gas migration severity. The reason is that it does not take into account the pressure behavior in the annulus. Another drawback of SRN is that the number does have any physical meaning. It has only a relative worth, i.e. a higher value is better than lower.

Slurry Performance Number comprises four different factors which are believed to be important in evaluation of gas migration severity [8]:

- Formation Factor,
- Hydrostatic Factor,
- Mud Removal Factor,
- Slurry Performance Factor.

The SPN method due to its high complexity and doubtful merit has not been accepted. None of the above methods can be applied to analyze the data meaningfully.

A model of pressure loss in the cemented column has been chosen to see if there is any relationship between time to gas flow on the surface and time to pressure balance between cement column pressure and gas formation pressure.

The model used for the analysis is a simplified model described in the section devoted to the new model of pressure loss Pressure loss is calculated using eqn. (4). The influence of filtration and chemical shrinkage on pressure behavior is taken into account by introducing a coefficient into the equation (4):

$$P_h(h,t) = P_{hi} - A(t) \cdot \frac{4 \cdot SGS(h,t)}{D_h - D_c} \cdot h \quad (4)$$

The coefficient A=f(t) is computed by taking first derivatives form the plots of SGS vs. time and chemical shrinkage vs. time. The values of the derivatives are then given weights to reflect the importance of each mechanism in pressure loss. In this model chemical shrinkage has been given 5 times less weight than fluid loss. Finally, coefficient A is normalized so that the maximum A is equal to 1 and corresponds to the most disadvantageous conditions. The influence of depth- i.e. temperature-has been taken into account in the similar manner. The maximum value on this coefficient never exceeds

1.5 (1 is for the surface), which means that we assume that in the bottom of the deepest well SGS develops ca. 50% faster than on the surface. Using this model, time to pressure balance as a function of depth has been computed for all 16 cases of flow as well as for the non-flowing wells. Additionally, only for the flowing wells, two different cement recipes have been modeled: neat cement and retarded cement with fluid loss additive. Typical output of the model is presented below:

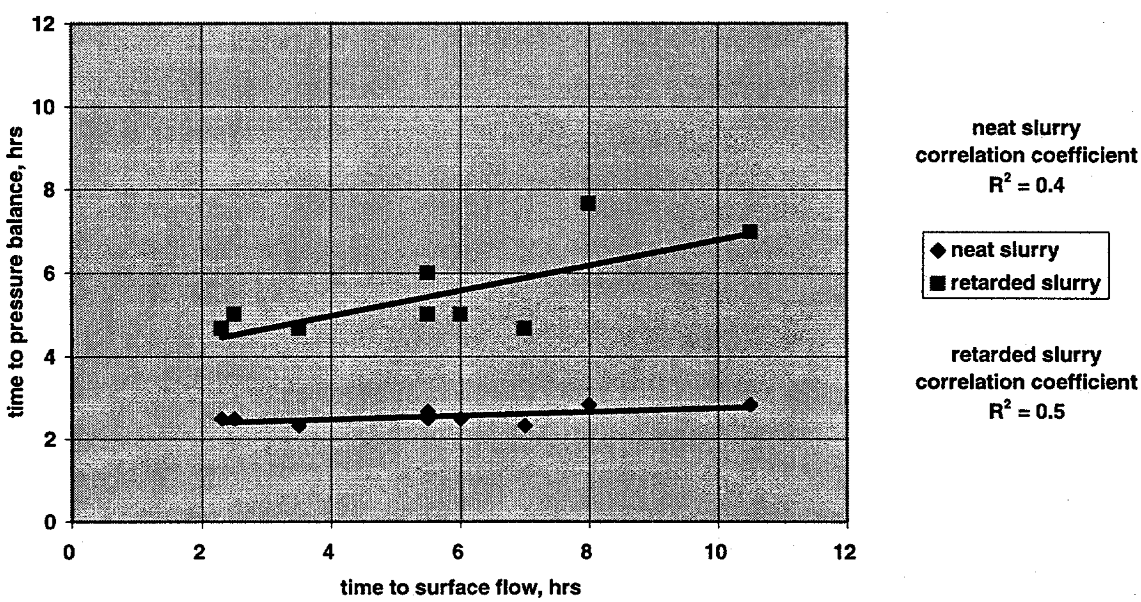
temperature effect coefficient	depth	initial hydrostatic pressure	pore pressure	time, min									
				80	90	100	110	120	130	140	150	160	170
				gel strength, lbf per 100 sq. ft									
d'less	ft	psi	psi										
				73	90	116	154	208	285	390	529	711	943
1.1	800	511	391	500	497	493	485	473	454	423	~~376~~	305	202
1.1	900	582	440	569	566	561	553	539	517	482	~~429~~	348	231
1.1	1000	653	489	639	635	629	620	605	580	541	~~481~~	390	260
1.1	1100	723	538	708	704	698	687	670	643	600	~~533~~	433	288
1.1	1200	794	587	777	773	766	754	736	706	658	~~585~~	475	315
1.1	1300	865	635	846	841	834	821	801	768	717	636	~~516~~	342
1.1	1400	935	684	915	910	902	888	866	831	775	688	~~557~~	368
1.1	1600	1077	782	1053	1048	1038	1022	997	956	890	790	~~638~~	419
1.2	1800	1218	880	1192	1185	1174	1156	1127	1080	1005	890	~~717~~	467
1.2	2000	1360	978	1330	1322	1310	1289	1257	1204	1120	990	~~795~~	513
1.2	2200	1501	1075	1468	1459	1445	1423	1386	1327	1234	1089	~~871~~	557
1.2	2400	1643	1173	1605	1596	1581	1556	1515	1450	1347	1186	~~946~~	598
1.2	2600	1784	1271	1743	1733	1716	1689	1644	1572	1459	1283	~~1019~~	637
1.2	2800	1926	1369	1881	1870	1851	1822	1773	1694	1570	1378	~~1090~~	673
1.3	3000	2067	1466	2018	2006	1987	1954	1901	1816	1681	1473	~~1159~~	707
1.3	3200	2208	1564	2156	2143	2121	2086	2029	1937	1792	1566	~~1227~~	738
1.3	3400	2350	1662	2293	2279	2256	2218	2157	2058	1901	~~1658~~	1294	767
1.3	3600	2491	1760	2431	2416	2391	2350	2284	2178	2010	~~1750~~	1359	794
1.3	3800	2633	1857	2568	2552	2525	2482	2411	2298	2118	~~1840~~	1422	818
1.3	4000	2774	1955	2705	2688	2660	2614	2538	2417	2226	~~1929~~	1483	840

The values presented in the above table are for the event #5. The crossed out values of pressure are the earliest values which are smaller than pore pressure. Similarly, such a table has been created for all other cases of gas flow. It can be noticed that time to pressure balance varies with depth. It depends strongly on well configuration as well as cement job design. Earliest time to flow is equal to 150 min., while the flow on the surface has been eported to occur 10.5 hrs after CIP. Data for all cases are summarized in the following able:

	Flowing Wells				Non-Flowing Wells
	Flow observed on surface hrs	FPF d'less	Time to earliest pressure balance hrs		Time to earliest pressure balance hrs
			neat slurry	retarded slurry	neat slurry
	?	0.9	2.5	5.0	2.2
	?	4.5	2.5	5.0	2.5
	?	2.6	2.3	4.8	2.7
	5.5	4.1	2.5	5.0	2.5
	10.5	1.2	2.8	7.0	2.7
	3.5	3.1	2.3	4.7	2.7
	?	2.2	2.5	5.3	2.5
	?	1.0	2.5	5.0	2.5
	5.5	3.8	2.7	6.0	2.5
	2.3	2.8	2.5	4.7	2.5
	?	3.0	2.5	5.0	2.5
	8.0	2.7	2.8	7.7	2.5
	7.0	1.5	2.3	4.7	2.3
	6.0	4.3	2.5	5.0	2.3
	2.5	3.5	2.5	5.0	
	5.5	4.7	2.5	5.0	
Average:	5.6	2.9	2.5	5.3	2.5

In order to examine if there is a correlation between the time when flow was observed on the surface and the time to earliest pressure balance, plots of the two times have been prepared, as seen below:

Correlation between time when flow was observed on the surface and calculated time to pressure balance



The examination of the graph as well as computed values of correlation coefficients show that there is no correlation between the two times both for neat slurry as well as for retarded slurry.

The method used to analyze case histories failed. After all, it is clear from the study that very high potential exists in the pressure loss model. The reason for such poor results lies in the low quality and small amount of data gathered to perform the analysis.

The following conclusions can be drawn based on the above study:

- analysis of past events using pressure loss model is dependent on the quality of input data; in case when reliable data cannot be obtained, resulting model may be only of qualitative value;
- the lack of accurate input data seriously impaired the quality of results of the study,
- there is a need for establishing good databases of all cementing jobs offshore; it is a necessary prerequisite for learning from past incidents.

Based on the analysis of existing databases of well cementing [79], a model database storing past incidents of flow should include at least:

⇒ well location, area and operator,
⇒ pore pressures and fracturing gradients,
⇒ type of cement used,
⇒ cement density,
⇒ all cement additives used plus their concentration,
⇒ cement properties if measured,
⇒ well configuration,
⇒ wellbore lithology,
⇒ wellbore temperature,
⇒ volume of cement pumped,
⇒ mud type and properties,
⇒ any unusual events like lost returns, pressure in the annulus, etc.,
⇒ results of any MWD, LWD and post-job CBL logs;

Pressure loss model may help analize the events. It may also be an excelent designing tool helping estimate the depth at which cement will loose its hydrostatic pressure the soonest. This analysis shows clearly that prediction of this depth with such a model is possible.

Model proposed here may also help estimate fluid loss due to filtration. Filtration may be one of the most important mechanisms leading to gas migration in the Gulf of Mexico, mostly due to large intervals of formations with relatively low pore pressure and high permability. To estimate fluid loss, three different models have been used. The first was based on the following equation:

$$V_{fl} = K \cdot \sqrt{t} \qquad (25)$$

The value of constant K has been found in the literature [16].

The second method utilizes Darcy's law with cement and mud cake contributions, as in eqn. (14). Since cement cake thickness is time-dependent, the equation has to be integrated.

Final relationship is:

$$V_f = \frac{-\mu \cdot \frac{e_m}{k_m} + \sqrt{\left(\mu \cdot \frac{e_m}{k_m}\right)^2 + 2 \cdot \frac{\mu \cdot R}{k_c} \cdot \Delta P \cdot t}}{\frac{\mu \cdot R}{k_c \cdot A}} \qquad \text{(26)}$$

The values of cement cake permeability, fluid viscosity, mud cake thickness and mud cake permeability was found in the literature [74]. Finally, the third method is similar to the second with the exception that cement permeability has been obtained from [74] and [9].

The results from all the three methods are presented in the table that can be found in the next page.

It is clear upon the examination on the above table that fluid loss may be indeed a very important mechanism leading to gas migration in the Gulf of Mexico. It is worth noting that the bottom part of the cement column will always exhibit the highest fluid losses. It is therefore, highly recommended that tail slurry contain good fluid loss control agent.

CONCLUSIONS:

1. Hydrating cement slurry undergoes a structural change from a dense suspension to solid body. First part of the transition is well described and understood. The second, does not provide us with an answer to the question regarding the condition of gas entry and migration in the slurry.
2. Current operational procedure focus attention on proper hole cleaning, and careful job design and execution (supervision). There are no industrial standards sanctioning or enforcing the best course of action.
3. Prediction of cement column pore pressure can be based on cement gelation only to a certain time, later on cement permeability changes, volumetric changes and resulting forces within cement column determine pore pressure of hydrating cement.
4. Gas migration test cell designed by Cheung and Beirute is presently the best method of cement selection to prevent gas migration.
5. It is highly recommended that gas migration test procedure and reporting are standardized. Also, a new method to scale down field conditions has to be established.
6. Vibration of cement slurry is the most promising method of mechanical prevention of annular flow after cementing.
7. Use of predictive techniques based on indexing should be avoided.
8. Modeling pressure loss in the cementing column may become a means of prediction/past analysis of flow problems. Results depend, however, very strongly on the quality of input data.
9. A standard for cementing job database has been proposed.
10. Model used in this study shows that excessive filtration may occur in downhole conditions in offshore GoM. Cements with good filtration control are crucial to the successful prevention of fluid flow. Tail slurry is exposed the most to high fluid loss.

COMPUTATION OF CEMENT COLUMN FLUID LOSS FOR ONE OF THE FLOWING WELLS

										k_c=	R=	m=	e_m=	k_m=				cement permeability after ref [], darcies							
										0	2	0	0.01	0				0.005	0.005	0.004	0.004	0.003	0.003	0.003	0.002
time:	min	10	20	30	40	50	60	70	80	10	20	30	40	50	60	70	80	10	20	30	40	50	60	70	80
depth:		fluid loss from 1 ft section, % of the original volume								Darcy law, mud and cement cake								Darcy law, cement cake permeability							
ft		50% of the open hole section is permeable strata								permeability from ref [] and []								100 times smaller than							
		V~sqrt(t)																cement body permeability							
900		4%	6%	7%	8%	9%	10%	11%	12%	2%	4%	6%	7%	8%	9%	11%	11%	3%	5%	7%	9%	10%	12%	13%	14%
1000		4%	6%	7%	8%	9%	10%	11%	12%	3%	5%	6%	8%	9%	10%	12%	13%	3%	6%	8%	10%	12%	13%	14%	16%
1100		4%	6%	7%	8%	9%	10%	11%	12%	3%	5%	7%	9%	10%	11%	12%	14%	3%	6%	9%	11%	13%	14%	16%	17%
1200		4%	6%	7%	8%	9%	10%	11%	12%	3%	6%	8%	9%	11%	12%	13%	15%	4%	7%	10%	12%	14%	16%	17%	18%
1300		4%	6%	7%	8%	9%	10%	11%	12%	4%	6%	8%	10%	12%	13%	14%	15%	4%	8%	10%	13%	15%	17%	18%	20%
1400		4%	6%	7%	8%	9%	10%	11%	12%	4%	6%	9%	11%	12%	14%	15%	16%	4%	8%	11%	14%	16%	18%	19%	21%
1600		4%	6%	7%	8%	9%	10%	11%	12%	4%	7%	9%	11%	13%	14%	16%	17%	5%	9%	12%	15%	17%	19%	21%	22%
1800		4%	6%	7%	8%	9%	10%	11%	12%	4%	7%	10%	12%	14%	15%	17%	18%	5%	9%	13%	15%	18%	20%	22%	23%
2000		4%	6%	7%	8%	9%	10%	11%	12%	5%	8%	11%	13%	15%	17%	18%	20%	6%	10%	14%	17%	20%	22%	24%	25%
2200		4%	6%	7%	8%	9%	10%	11%	12%	5%	9%	12%	14%	16%	18%	20%	21%	6%	12%	16%	19%	22%	24%	26%	28%
2400		4%	6%	7%	8%	9%	10%	11%	12%	6%	10%	13%	15%	18%	20%	21%	23%	7%	13%	17%	21%	24%	26%	29%	31%

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FEASIBILITY STUDY OF A DUAL DENSITY SYSTEM FOR DEEPWATER DRILLING

by

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OBJECTIVE

The objectives of this project are to determine the advantages, disadvantages, technical feasibility and economic feasibility of the use of gas lift in a marine riser to maintain the pressure in a subsea wellhead equal to the hydrostatic pressure of the seawater outside of the wellhead. Such a dual density system for drilling in deep water would have one effective fluid gradient between the surface and the seafloor and another fluid gradient within the subsea well. This would in effect reduce the casing design problem to that of an equivalent on-shore well. This paper gives a summary of our progress to date.

SUMMARY

Recent successful exploration efforts in deep water have heightened interest in developing oil and gas reservoirs on the continental slope. Leases have been obtained in water depths of up to 10,000 ft with a requirement that they be drilled within the next decade. Use of current techniques to drill these leases will require extremely large floating drilling units and large diameter marine riser systems. This paper presents the results of a feasibility study of the use of an automated gas-lift system for a marine riser that will maintain the hydrostatic pressure in the subsea well-head equal to the hydrostatic pressure of the seawater at the seafloor. Hydrostatic control of abnormal formation pressure could still be maintained by a weighted mud system that is not gas-cut below the seafloor. Such a dual density mud system could reduce drilling costs by reducing the number of casing strings required to drill the well and by reducing the diameter requirements of the marine riser and subsea blowout preventers. The system would have the advantages of riserless drilling without giving up the well control advantages of a closed, weighted mud system.

An unsteady-state numerical model was developed that can be used to determine the gas injection requirements needed to achieve a desired dual density configuration. The numerical model is being verified through tests conducted in a 6000 foot research well and through field data collected by downhole pressure sensors during underbalanced drilling operations. Once verified, the model is being used to define the gas requirements and practical limits of a marine gas-lift system based on estimated additional costs of gas injection. Rough estimates were made for the cost of using (1) gas compression and nitrogen membrane filters and (2) stored liquefied nitrogen or natural gas. The gas requirements are presented in terms of maximum mud density, water depth, and riser diameter combinations. The paper also discusses the operational changes that would be required for various drilling procedures such as making a connection, running casing, kick detection, and well control operations.

INTRODUCTION

Drilling operations in waters deeper than 3,000 ft are increasing throughout the world, and the industry is now looking into the challenges imposed by ultra-deep waters (> 7,000 ft).

One of these challenges comes from the fact that the current technology relies on the use of marine risers to extend the well up to the drilling vessel, so the mud and tools can get in and out of the well in much the same way that is done on land. However, when drilling with mud densities in excess of sea water density, the exposed sediments in the open borehole see a pressure tending to cause formation fracture that is affected by the full column of drilling fluid all the way up to the drilling vessel. The overburden pressure of the sediments tending to help resist formation breakdown is generated by sediment densities in excess of seawater hydrostatic only from the mudline down. This causes the fracture gradient, when expressed as an equivalent mud density, to be much lower than for an equivalent casing penetration into the sediments of an onshore well. The reduction in fracture gradients are more significant in the deeper water depths and tend to impose a limit to deep water drilling operations. This limit comes about because of the increased number of casing strings needed to reach a given depth objective in a given formation pore pressure environment. It has long been recognized that one way of overcoming this problem would be to effectively start the well at the mud line with the pressure inside of the well being no greater than the pressure outside of the wellhead.

In order to better understand the effect of the mud density in the marine riser on the fracture gradient, consider the pore pressure and fracture gradient curves that are shown in Figure 1 for a well drilled in the Gulf of Mexico in 3750 ft of water. In Figure 1, both the pore and fracture pressure gradients are expressed as an equivalent density of a column of mud between the exposed formation and the rig floor. This is the conventional presentation format of the data used in selecting the casing setting depths needed to drill the well. Note that the spread between the pore pressure and fracture gradient lines is much less than normally seen for drilling operations on land or in shallow water. Note also the large number of casing strings needed to drill this well.

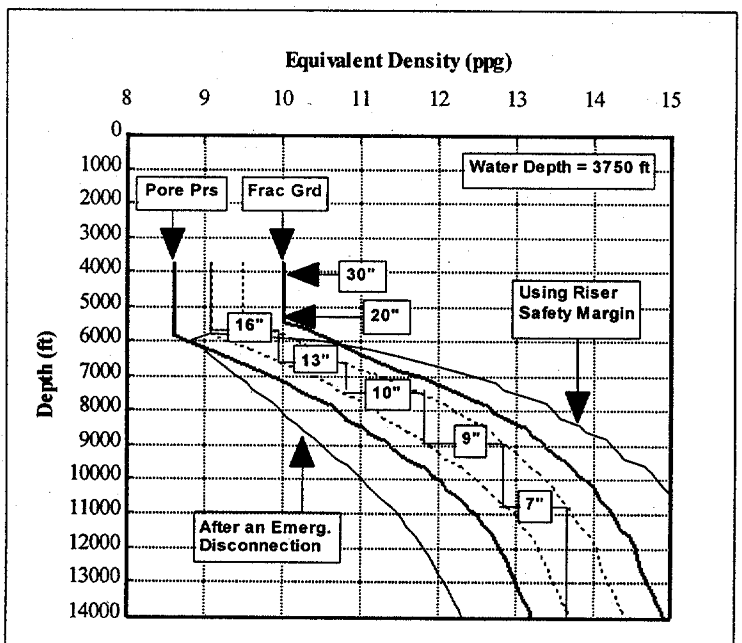

Figure 1- Example Gulf of Mexico Deep Water Well

The pore pressure gradient and fracture gradient data have been converted to pressure values in Table 1 for a 25 ft air gap between the rig floor and sea level. This presentation format further illustrates the narrow spread between pore pressure and fracture gradient when the mud column extends all the way to the rig floor. Computing the pressure values also allows the data to be displayed on a graph of pressure versus depth as shown in Figure 2. In this type of presentation, the pressure generated by a column of mud from the surface plots as a straight line with the origin at the surface. In order to drill to the target depth, a mud weight of about 13.5 ppg would be needed (Point A). Following this line of constant mud density back to an intersection point with the fracture gradient line (Point B) defines the minimum depth of casing that must be set to reach the bottom of the well. Of course, use of a safety margin would require casing to be set deeper that this depth.

Table 1 - Pore Pressures and Fracture Pressures

Depth (ft)	Pore Pressure (ppg) [RKB]	Pore Pressure (psi)	Fracture Gradient (ppg) [RKB]	Fracture Gradient (psi)
0	8.6	11	8.6	11
-3750	8.6	1666	8.6	1666
-3800	8.6	1688	10	1963
-6200	9.1	2922	10.9	3500
-7800	10.6	4286	12.6	5094
-9000	11.4	5320	13.4	6254
-10000	12	6224	13.9	7210
-14000	13.2	9592	14.9	10828

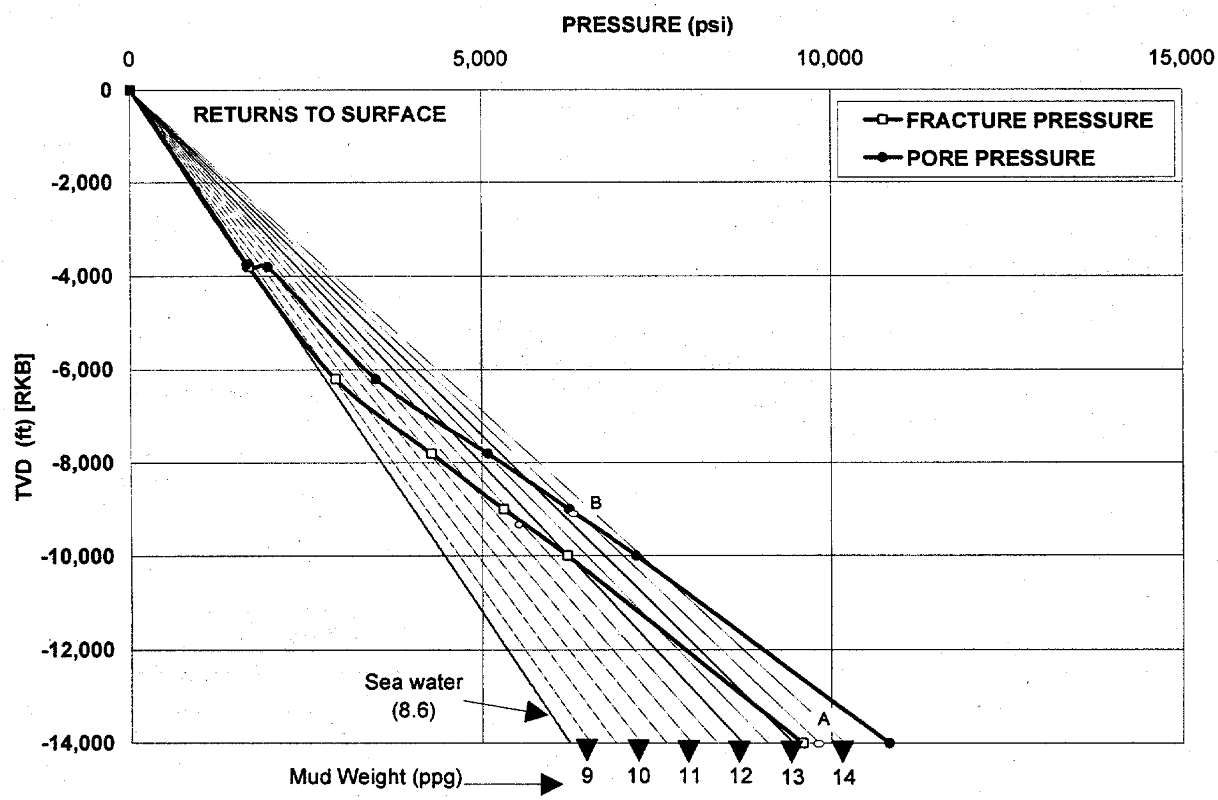

Figure 2 - Pore Pressure and Fracture Pressure versus Depth.

In order to better understand the benefit of riserless drilling, lets assume for the moment that we have the capability to start a well at the seafloor. Lets pretend that subsea drilling vessels (which have been the subject of science fiction movies) are available for hire. The drilling fluid would only have to be returned to the seafloor, which would be maintained at the hydrostatic pressure of the seawater. In this case, the lines of constant mud density would start at the seafloor as shown in Figure 3. Note that a higher mud density would be required in the well to overcome formation pressure (Point A). However, note also that the minimum depth of casing required to reach this depth (Point B) would be less than for the situation of Figure 2.

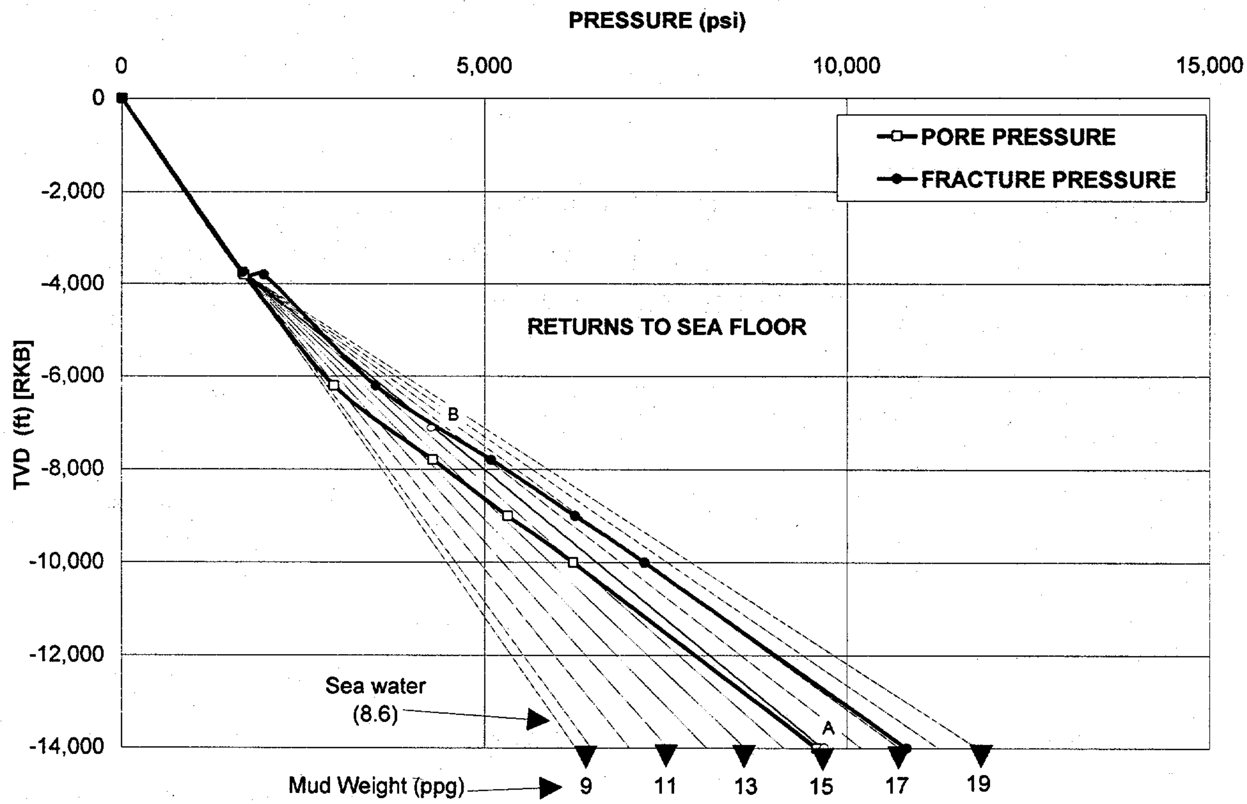

Figure 3 - Pressure versus Depth for Mud Returns to Seafloor

The use of subsea mud tanks that are pressure equalized with the ocean have been proposed in the past as a means of achieving the situation shown in Figure 3. Subsea pumps would be needed to pump the mud from the subsea tank to the surface. Another solution being considered is the placement of mud pumps on top of the BOP stack at the sea floor (McLeod, 1976 and Gault, 1996). The riser would be replaced with a smaller diameter subsea flowline for mud return from the seafloor. Another way of achieving this situation might be the injection of gas at the BOP level in order to lower the effective riser annular density to sea water values. Since weighted mud will still be pumped through the drill pipe, we are dubbing this solution the Dual Density Riser System which is illustrated in Figure 4. The system dynamics would be closely related to that of gas lifting operations, and a similar set of valves could be used to assist in the unloading of the riser annulus.

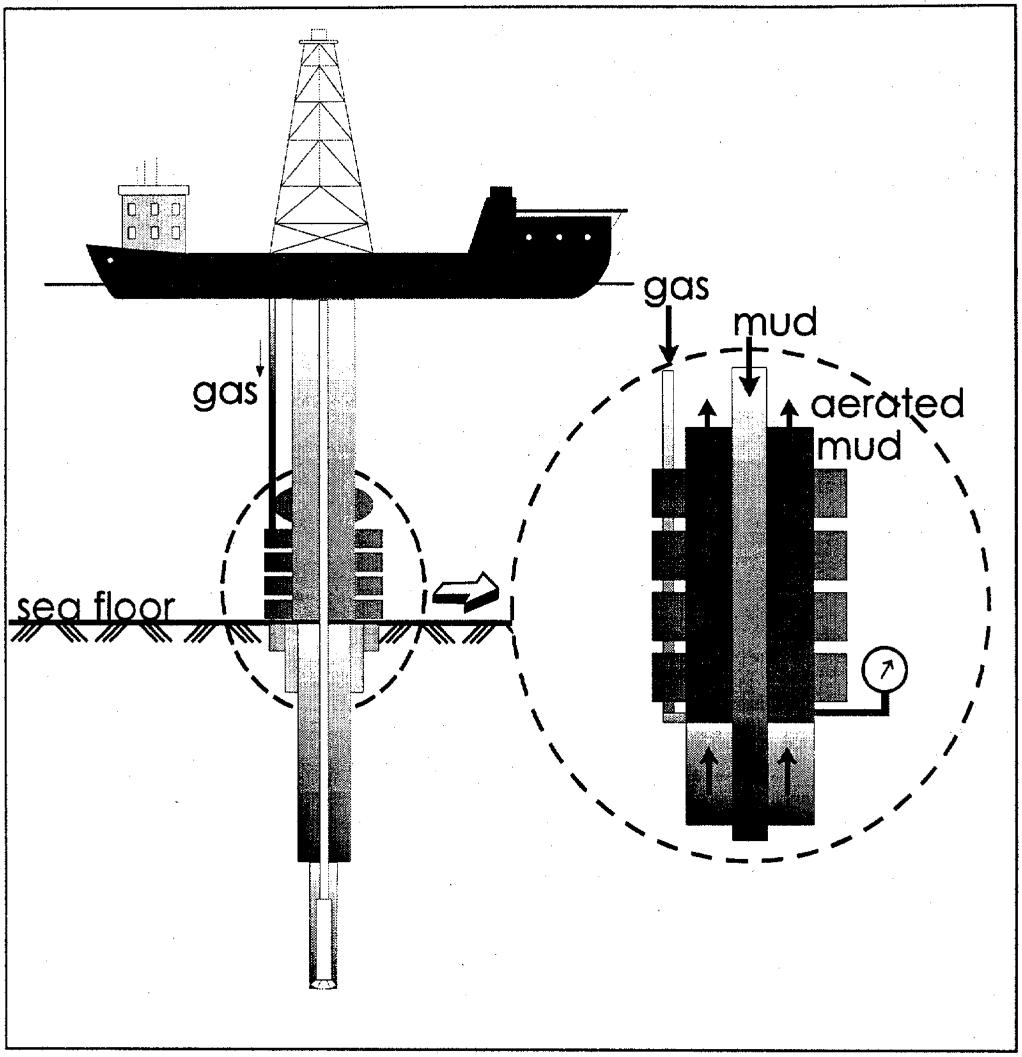

Figure 4 - Dual Density Concept Achieved by Gas Lifting Marine Riser

Gas lifting the surface casing is currently being practiced as a means of drilling underbalanced on land. In some cases, a parallel gas injection string is cemented outside of the surface casing with a connection to the interior of the casing near the casing seat. Gas is injected down this gas injection string while drilling with a rotating control head at the surface. In other cases, gas is injected down an annulus formed by an inner string of casing run concentrically inside the surface casing. Gas injection into a marine riser on a deepwater rig would be similar in its geometric configuration to the underbalanced drilling situation described above, except that the well would not be drilled underbalanced.

The large number of casing strings needed to drill an abnormally pressured well in 10,000 ft of water with conventional technology will require much bigger rigs than are used today because of the increase in diameter of the starting hole size. Use of conventional technology will require the construction of rigs estimated to cost about $300,000,000 with day rates in excess of $200,000. A fresh look at alternative technology is needed to try and make drilling in deep water feasible without such a large increase in rig size and drilling costs. Gas lifting the marine riser would require less significant changes in the drilling equipment used at the seafloor on a deepwater well than other alternatives, such as the use of subsea mud pumps, being discussed. The feasibility of a gas lift system on a marine riser is the subject of this study.

RESEARCH

A computer simulator was developed to investigate the gas rates, pressure and velocity profiles, and unloading times required for offshore operations. Experiments are currently being set up to validate the software. These experiments will use the facilities available at LSU's Petroleum Engineering Research & Technology Transfer Laboratory. Figure 5 shows the schematics of the 6,000 ft well that will be used. Nitrogen will be injected from a cryogenic tank, mounted on a service truck, into an 1 ¼" pipe inside a 3 ½" tubing. Drilling mud will be pumped into the annulus between these tubulars, mixing at the bottom. The mixture returns through a 9 5/8" casing annulus and the data will be collected by sensors inside an auxiliary 2 3/8" perforated tubing, also inside the casing. These sensors are run by a conventional logging unit. The information of some of the sensors will be recorded on line, with a data acquisition system, while other sensors will store the data on RAM memory where it can be retrieved at the surface after each test.

Equivalent Density Equations

In a conventional well, the equivalent density provided by the mud column is a linear function of depth. This is not true when another fluid column is added on top of the mud. In the Dual Density Riser System, the mud weight to be used is calculated as if there were no riser string and is heavier than it would be in a conventional well. For any given depth D2, there is an associated pore pressure Pp. Adding a trip margin (TM) to Pp and taking into account a water depth H and a sea water density ρw, , the dual density equivalent mud weight for that depth is as follows:

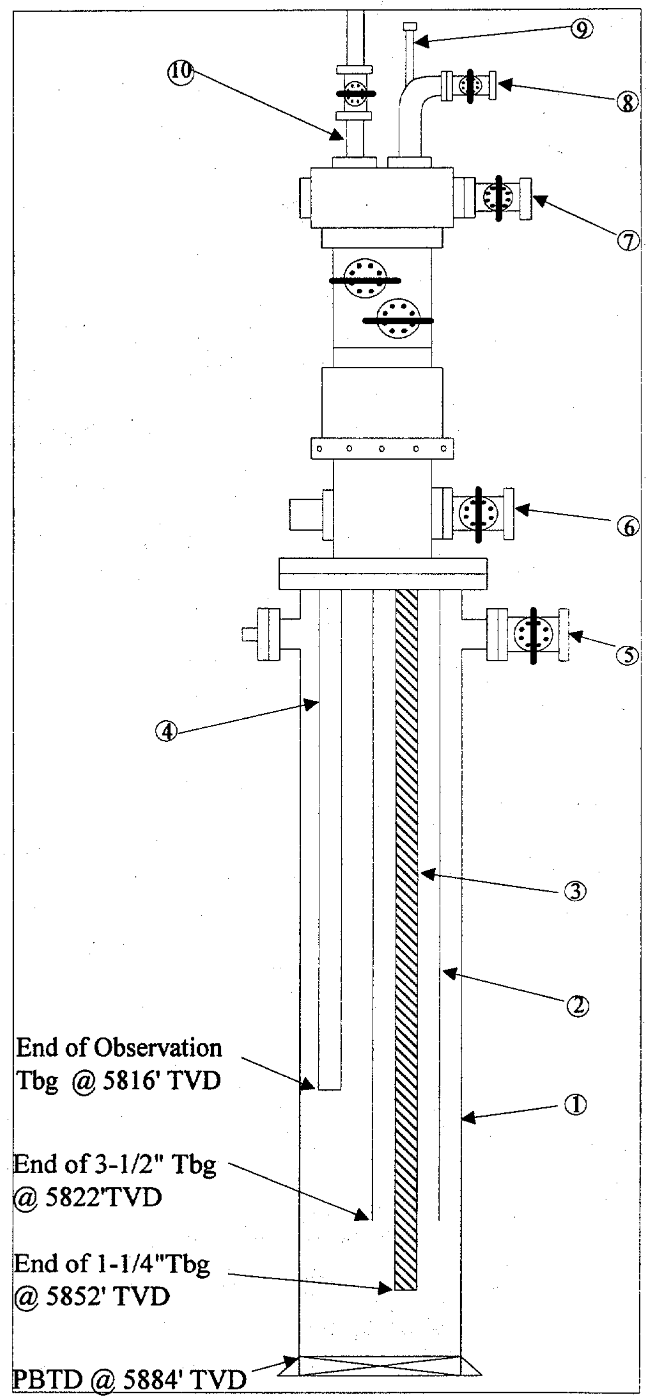

Figure 5 - Research Well Schematics

$$\rho_{DD} = \frac{(P_p + TM)D_2 - \rho_w H}{(D_2 - H)} \tag{1}$$

At a shallower depth D1, if we have ρDD from D2 up to the sea floor, the hydrostatic pressure will be calculated with an equivalent density ρD1/D2 (at D1, given D2) that is:

$$\rho_{D1/D2} = \frac{\rho_{DD}(D_1 - H) + \rho_w H}{D_1} \tag{2}$$

If we let ρ_p = (P_p + TM), substitute equation (1) into (2), and rearrange terms, the equation becomes as follows:

$$\rho_{D1/D2} = \frac{(\rho_p D_2 - \rho_w H)}{(D_2 - H)} + \frac{D_2(\rho_w H - \rho_p H)}{(D_2 - H)}\left[\frac{1}{D_1}\right] \tag{3}$$

Since the first fraction is essentially positive and the second is always negative, the term $\rho_{D1/D2}$ becomes increasingly small as D_1 becomes increasingly small. However, the equiv-alent density now varies with the reciprocal of the depth. The general equation form is of the type:

$$y = a - b\left(\frac{1}{x}\right) \tag{4}$$

If we equate D_1 to D_2, $\rho_{D1/D2}$ equals ρ_p. Figure 6 shows an example graph.

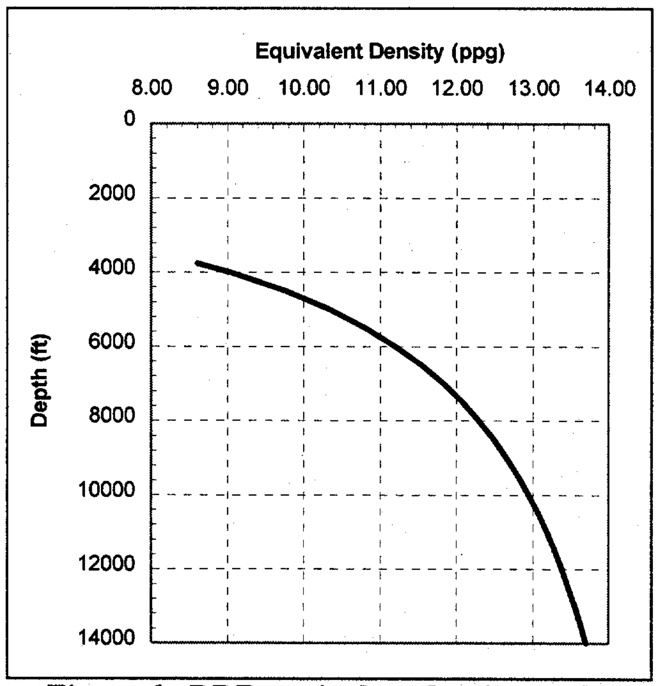

Figure 6 - DDR equivalent density profile

The Riser Margin

In any floating drilling vessel there is always the chance of an emergency riser disconnection. This type of situation is usually caused by weather conditions, pushing the vessel away from its location, or by failure of the mooring system. The risk is greater in dynamically positioned vessels.

If the mud weight is greater than the sea water density, the fluid column composition changes after a marine riser disconnection. There is a decrease in hydrostatic pressure at the bottom of the well due to the replacement of the drilling fluid from the rig floor down to the seafloor by sea water. This loss of hydrostactic pressure is almost instantaneous following an emergency disconnection. Since the possibility of an emergency disconnection is an ever present one, this has to be considered when determining the mud density to be used. It is desirable that, at all times, the sum of the total hydrostatic pressure provided by the mud from the bottom of the well up to the seafloor and the column of sea water from the seabed up to the ocean surface be greater than the pore pressure of any of the formations exposed. But there is a mud density upper limit which is determined by the minimum fracturing pressure of the exposed formations. In this case, we have to consider the hydrostatic pressure generated by the drilling fluid column from the rig floor down to the weakest formation. Furthermore, the formations tend to show lower fracturing resistances as the water depth increases, and this tends to narrow the operational mud range.

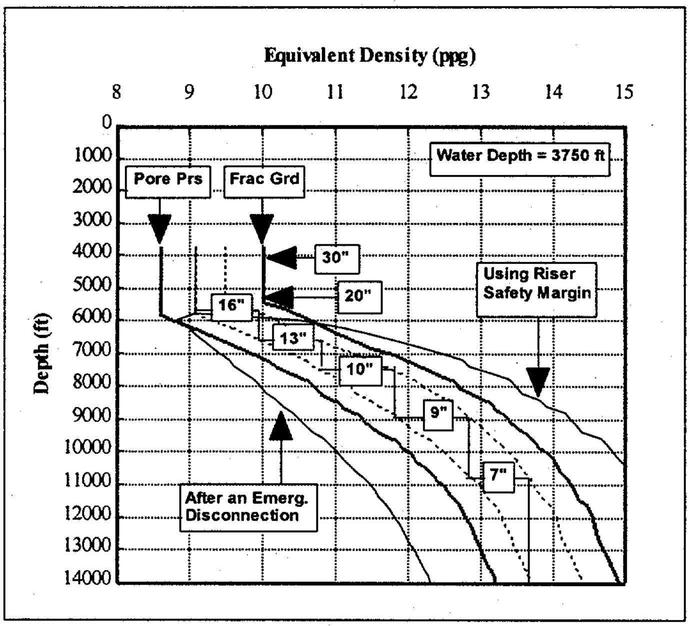

Figure 7 - Example Gulf of Mexico Deep Water Well

We can define Riser Safety Margin as the difference between the equivalent density of the combined hydrostatic column (provided by mud and sea water) and the pore pressure equivalent density, plus a safety margin. In equation form:

$$RM = \frac{\rho_m (D-H)}{D} + \frac{\rho_w \cdot H}{D} - (P_p + SM) \qquad (5)$$

Thus, the maximum Riser Margin can be expressed in terms of the fracturing equivalent density since that is the upper mud weight limit:

$$RM_{max} = [(F_p - KM) \times \frac{(D-H)}{D}] + \frac{\rho_w \cdot H}{D} - P_p - SM \qquad (6)$$

Figure 7 shows data from an example well in the Gulf of Mexico. The upper curve represents the mud density required to drill using a minimum Riser Margin of 0.5 ppg. The bottom curve shows the equivalent density profile provided by the combination of mud and sea water hydrostatic columns after a disconnection when using a mud weight equal to the pore pressure plus a trip margin factor.

In the former case, the use of a riser margin would have fractured the formation, while in the latter, the well would be exposed to an influx from the formation since the hydrostatic pressure along the well would be less than each formation pore pressure. This no-win situation began a little after the riser was run, and continued until the end of this well. In the actual case, the operator had to give up using a riser margin altogether.

Savings on Rig Time and Casing

In the previous example, the well was cased with 7 strings. Many of these strings required under-reaming, due to the small diameter differences between them. Figure 8 shows a study of the casing design if a dual density riser system were in use.

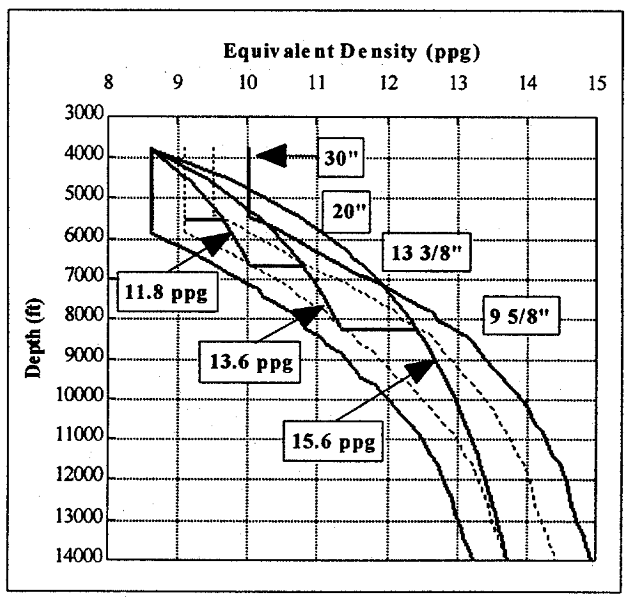

Figure 8 - Dual Density Casing Design for the GOM Example

In order to conduct a cost comparison between the two designs, a few assumptions were made:

- No problems occurred during the under-reaming jobs;
- Rig day rate was estimated at US$ 100,000 per day;
- Time required to under-ream was estimated to be 2 days per section of hole;
- Time required for each casing job was also 2 days.
- Casing designs did not include any non-API pipe and costs were taken as average.

Table 2 shows the cost differences between the two systems. An estimated total of 12 days could be saved in rig time, if the dual density riser system was in place.

Method	U-Reaming Time	Casing Time	Casing Cost	Total Cost
Conventional	8 days	14 days	$ 555,847.00	$ 2,755,847.00
Dual Density	2 days	8 days	$ 184,019.00	$ 1,184,019.00
Difference	6 days	6 days	$ 371,828.00	$ 1,571,828.00

Table 2 - Casing Costs for the GOM Example

Operational Costs

A computer simulator was used to estimate the gas volumes and pressures required to implement the Dual Density Riser System. The input data for the Gulf of Mexico example is shown in Table 3. The Hole Diameter column corresponds to those usually drilled for the 13 3/8", 9 5/8" and 7" casing strings. The mud densities were taken from Figure 8. The pump rates are average values used for the diameters cited. The Top Pressure values are estimates for the choke pressures to be held during steady state flow conditions. The Time column holds the values estimated to be enough to drill each hole diameter listed. The last column is a percentage of the corresponded time value dedicated to circulation.

Hole Diameter (in)	Mud Weight (ppg)	Mud Rate (gpm)	Top Pressure (psi)	Time (days)	Circulating (%)
17.50	11.8	900	100	10	40
12.25	13.6	600	70	10	50
8.50	15.6	400	60	15	60

Table 3 - Simulation Conditions for Gulf of Mexico Example

The simulation results are tabulated in Table 4. The Hole Diameter column was included for correlation with Table 3 while the Running Pressure column states the steady state pressure estimated. The third column shows the pressure values required to overcome the hydrostatic and friction pressures prior to the riser unloading. The Gas Rate column lists the simulator nitrogen input to achieve a mixture density equivalent to that of the sea water: 8.60 ppg. The last column

Hole Diam (in)	Run Press (psi)	Max Press (psi)	Gas Rate (SCF/min)	Gas Vol. (MMSCF)
17.5	1,344	2,390	8,506	48.992
12.25	1,344	2,679	8,896	66.819
8.5	1,344	3,097	10,508	136.186

Table 4 - Gas Volumes and Pressures for the GOM Example

shows the estimated gas volumes, in MMSCF, necessary to complete each drilling stage.

There are two ways to deliver nitrogen at these pressures to the riser annulus: (1) produce the gas aboard the rig using membrane generators and boost it up to the working pressure with gas compressors, or (2) heat up liquid nitrogen previously stored in cryogenic tanks to obtain the required gas rates and pressures.

The first alternative requires the use of Nitrogen Producing Units or NPU's (see Appendix). Since these units support a maximum rate of 3,500 SCF/min, a minimum of 4 units (including an extra one for back-up during maintenance) would be necessary. This would translate into a rental cost of approximately US$ 157,500.00 for the current example [9]. The compressor size needed would depend on the possibility of reducing the unloading pressure requirements. The adoption of gas lift valves along the riser string is one viable solution. Another could be the use of liquid nitrogen for unloading operations only.

Table 5 lists the estimated power requirements for this case. The operating costs were calculated based on an average diesel engine efficiency of 23.4% and a fuel price of US$ 1.50/gal. In this scenario, the cost of fuel and capitalization could be as high as US$ 237,000.00. This brings the overall cost of generation and compression up to around US$ 400,000.00.

Compressor	Gas Rate	Pressure	Power	Total Cost	Spec Cost
	(SCF/min)	(psi)	(Bhp)	(dollars)	($/MSCF)
With Unload	10,508	3,097	2,303	236,998	0.95
Without Unload	10,508	1,344	1,701	175,085	0.70

Table 5 - Compressor Costs for the GOM Example

In the cryogenic option the rig would need a regular supply of liquid nitrogen off-loaded from special boats. The rig should hold cryogenic tanks with enough storage capacity for at least 3 days of operation. Table 6 presents the estimated values for the total volume of gas, and the liquid volume required for a 3 day storage tank. Since the liquid density of nitrogen is 6.738 ppg (at -320 degrees Fahrenheit) the liquid weight would be around 782 tons. The equipment needed for gas injection would include triplex pumps and vaporizers. These pumps can operate reliably for very long periods (more than 30 days) around the clock. The reported purchase cost for pumps and vaporizers capable of 12,000 SCF/min and up to 10,000 psi (not simultaneously) is around US$ 500,000 [10]. Since the power requirements are around 500 Bhp, operating costs should stay around US$ 60,000 for this example. The cost for the liquid nitrogen should stay below US$ 0.25/gal, bringing the total cost for this example up to around US$ 737,000.

Vapor		Liquid			
Total Volume	3 day Vol	Total Vol	3 day Vol	Weight	Total Cost
(MCF)	(MCF)	(gal)	(gal)	(tons)	(dollars)
251,997	21,600	2,706,446	231,981	782	676,611.44

Table 6 - Cryogenic Costs for the GOM Example

Although the results favor the first option, the liquid nitrogen alternative allows for a much greater operational range of pressures with readily available high injection rates. In either case the overall cost savings over the conventional methods are significant. Table 6 summarizes the cost savings for the two Dual Density options.

	Operating Costs	Nitrogen Costs	Sum	Casing Savings	Total Savings
NPU's	$236,998.00	$157,500.00	$394,498.00	$ 1,571,828.00	$1,177,330.00
Cryogenic	$60,000.00	$676,611.44	$736,611.44	$ 1,571,828.00	$835,216.56

Table 7 - Summary of Dual Density Cost Savings for GOM Example

Top Tension

The force needed to maintain the riser string under tension depends heavily on the density of the fluid within since the pipe weight in water is greatly decreased by the floatation devices surrounding it. The weight due to the column of mud inside the riser string has to be supported by the riser tensioners. With the Dual Density Riser system, the top tension could be greatly reduced. For example: the drillship *Pacnorse I* is rated for a 4910 ft (1500 m) water depth because it has a tensioning capacity of 960,000 lbf and an 18 $^{5/8}$ in. x 17.50 in. riser string [RSV Gusto Engineering, 1979]. The design criteria is as follows: maximum mud weight of 16 ppg (119.68 lbs/ft^3), buoyant weight equal to 10% of the riser string weight in air, and overpull of 50,000 lbf. According to Heuze et al. (1975), the tension required at the top of the riser is as follows:

$$\mathbf{F_T = R_w + M_w - B + O} \tag{8}$$

where R_W is the riser string weight in air, M_W is the weight of the mud inside, B is the buoyant force, and O is the overpull needed to keep the riser from buckling. By design, $(R_W - B) = 0.1\, R_W$. Thus, the riser length is related to R_W by:

$$\mathbf{R_w = h[\frac{490\pi}{(4 \times 144)}(OD^2 - ID^2)] = 108.614h} \tag{9}$$

if we solve for the riser length:

$$\mathbf{h = \frac{F_T - O}{(7.48\rho_m \cdot C_r) + 10.861}} \tag{10}$$

where C_r is the riser capacity per foot. After calculating the riser capacity per foot, we find C_r = 1.458 ft^3/ft. For the design mud weight of 16 ppg, h = 4908 ft (1496 m), while for sea water (8.5 ppg), h = 8,785 ft (2677 m). Thus,a 79% increase in water depth capability is realized in this case. In addition, the extra pulling capacity on the riser tensioners could also be used to straighten the riser string in locations were the marine currents are strong. This technique has been used successfully in the past in Brazil (Petrobras).

Pipe Connections

The bottom hole pressure is bound to increase in situations of no-flow, such as pipe connections, trips, casing runs, etc., if the gas in the annular mixture is allowed to escape, separating from the mud. First, after the pumps and gas injection have been stopped, the density difference between the mud inside the drill pipe and the annular will cause an U-tube effect. The heavy fluid will enter the riser annulus. At the same time, due to the gas separation, the annular level will fall until hydrostatic equilibrium is reached. There will be a slight increase in the bottom pressure due to the U-tube effect, and a pressure differential which will act to collapse the riser will result. However, the pressure fluctuations can be avoided if the gas injection is maintained during the whole process with a rate designed to maintain the mixture at sea water density level while maintaining the riser full. Also, there will be very little waiting to recommence flowing operations.

Kick Detection

Early kick detection presents a challenge for the implementation of a dual density riser system. Probably, any technique eventually developed for this purpose will depend on sensors installed at the BOP below the gas injection point. There are three systems that look promising cited in the literature. One method is the use of the negative pressure pulse generated by a MWD tool as a source signal. This signal travels up the annulus and can be monitored by a sensor at the BOP level. Acoustic amplitude and phase angle of the acoustic wave present large variations for small changes in the natural frequency or the damping ratio of the annular medium (Bryant et al, 1991).

Another technique is based on the use of a sonic interferometer installed in a MWD tool. Acoustic waves are generated between two parallel walls, and at certain frequencies the system is in resonance. Different fluids will show resonance at different frequencies, and the resonance is not disturbed by fluid flow. By varying the wave frequencies sent between the walls and monitoring the signal through an spectrum analyzer, the resonance peaks can be detected. If gas flows through the two walls, the resonance disappears since the medium has changed (Vestavik and Aas, 1990).

The above mentioned techniques have a significant drawback in that thy depend on having a tool in the hole and normally will not send any information unless the fluid is being pumped. One way to monitor the well while tripping or while the pumps are off is through the use of a wellhead sonar (Bang et al., 1994). Acoustic waves are generated at the BOP level and directed down the well while an acoustic sensor (also installed at the BOP) picks up the sonic reflections. If any gas is present in the mud, it will generate a reflection due to the difference in acoustic impedance between the mud and the gas-fluid mixture.

CONCLUSIONS

The proposed system offers:

- Lower bottom hole pressure, and thus smaller fluid invasion.
- Greater safety in case of emergency riser disconnections.
- Less casing and under-reaming runs, leading to less rig time per well.
- Less top riser tension requirements, extending the water depth capability and increasing the ability to weather high marine currents environments.
- It can be implemented with the available technology.

- The savings in casing programs alone offset the costs required for riser modifications, nitrogen generation and compression (or the cryogenic usage), and kick detection.

NOMENCLATURE

RM: Riser Margin (ppg);

D: Total Depth (well + riser) (ft);

H: Riser Length (ft);

ρ_w: Sea Water Density (ppg);

P_p : Equivalent Pore Pressure (ppg);

SM: Safety Margin (ppg).

KM: kick margin equivalent density, ppg;

F_p: fracture pressure equivalent density, ppg.

APPENDIX - NITROGEN GENERATORS

With the availability of NPU's (Nitrogen Producing Units), it is now possible to generate Nitrogen on site economically (World Oil, 1995). These units measure 8' x 8' x 40' and weigh approximately 1,500 lb. They can generate up to 3,000 SCF/min (Energy Technology Services Corp. Source) of gas composed of 93% of N_2. According to the source, the day rate for these units are upwards of around $ 900 per day, which includes satellite telemetry and maintenance.

Since the units are capable of delivering higher gas rates at a lower degree of purity, it is advisable to investigate the minimum oxygen percentage necessary to sustain combustion for a given site. The flammability limit can be affected by pressure according to (Allan, 1994):

$$\mathrm{MinO_2\%} = 13.98 - 1.68 \cdot \mathrm{Log(p)} \tag{11}$$

where p is the maximum expected pressure (psia) to which the mixture will be compressed. If the maximum pressure is 1,500 psia, the NPU could safely generate up to 3,500 SCF/min. Another consideration is corrosion caused by the compressed oxygen in the produced mixture. This has to be controlled by adding corrosion inhibitors to the mud.

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FINITE ELEMENT ANALYSIS OF SOFT SEDIMENT BEHAVIOR DURING LEAK-OFF TEST

by

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OBJECTIVE

The formation breakdown pressure is one of the most important parameters controlling the design of a well. Leak-off tests and formation integrity tests are routinely used to determine the breakdown pressure of sediments below surface casing and deeper casing strings. However, the use of leak-off tests below conductor casing to determine the breakdown pressure of soft shallow sediments has been avoided in the past because of a fear of causing irreversible damage to the cement/formation interface. Some operators have begun to routinely perform these tests and are reporting some higher than expected values of formation strength. However, other operators continue to avoid testing shallow sediments. The purpose of this paper is to report on the first phase of a theoretical study of sediment failure during leak-off tests conducted in soft shallow sediments. It is expected that this work will lead to a theoretical leak-off test model that could give a snapshot of sediment deformation as a function of volume pumped. It may also lead to improved leak-off test procedures for shallow sediments.

INTRODUCTION

Leak-off testing (LOT) in shallow (upper) marine sediments (UMS) is performed to estimate how much pressure can be applied to the rock just below the casing shoe before the shoe/rock system fails, just as for deeper formations. Also, the LOT procedures for both situations are conceptually the same; the shoe/rock system is stressed until the first sign of failure appears. The problem is that in deep rocks the beginning of failure (fracture) is well supported by theory and relatively easy to recognize. For shallow and soft rocks, this is not the case. As shown in Fig.1, for example, this deep-well LOT shows a distinct straight line and rapidly developing curvature indicating the start of elastic failure. This type of pressure response can be fully explained by the elastic rock model. The elastic rock model involves a linear stress-strain relationship and the maximum value of tangential stress at the wellbore wall to be overcome in order to initiate the fracture.

In shallow formations, particularly UMS, recorded LOTs sometimes give various plots with no clear indication of the beginning of failure. Moreover, as the elastic theory cannot explain nonlinearity of those plots other factors such as mud filtration, microfracturing or equipment malfunction must be hypothesized. Shown in Fig.2 is a LOT record with a nonlinear trend. The trend was confirmed by bleeding back 4.5 bbls of mud followed by pumping additional 3 bbls.

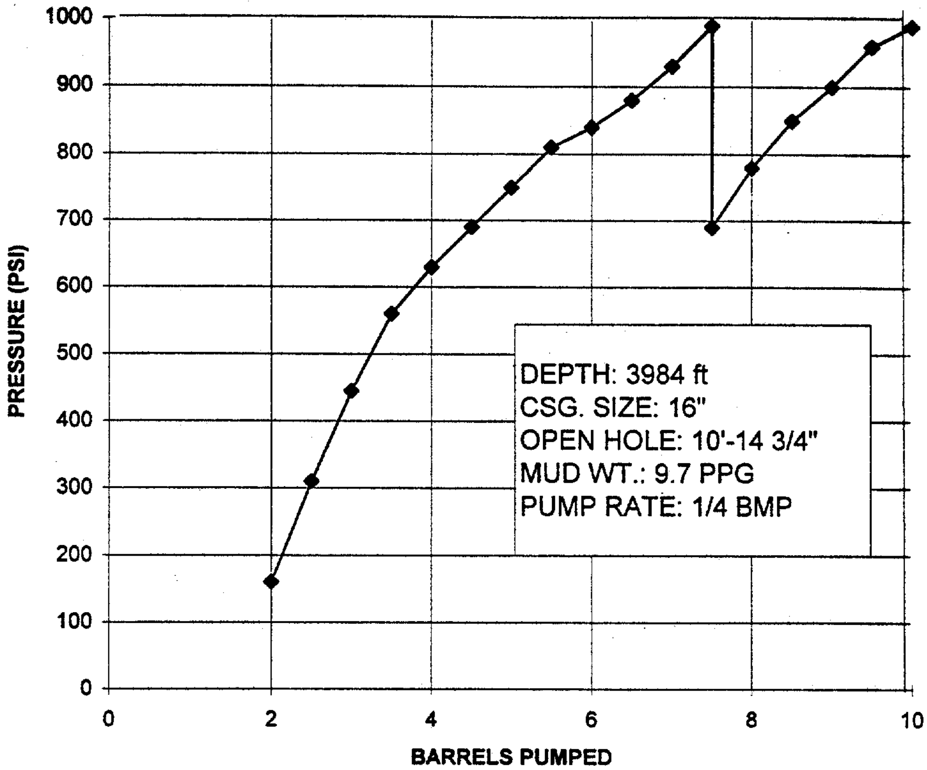


Figure 2. Nonlinear LOT in shallow sediments (depth 3,984 ft.)

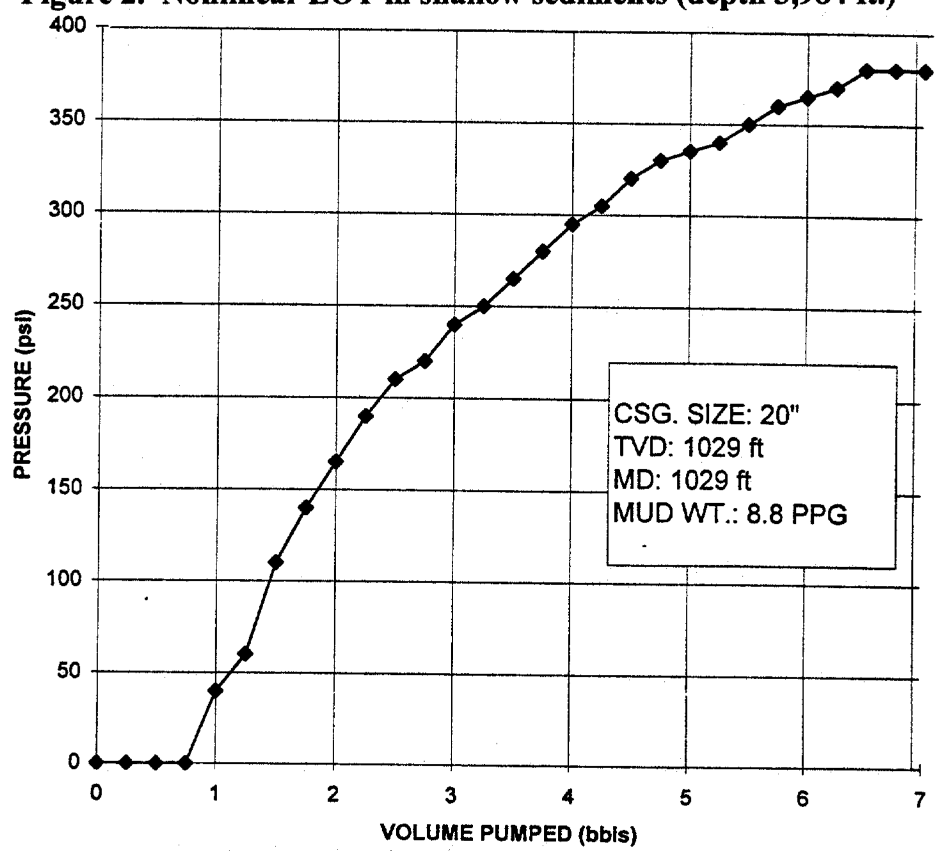
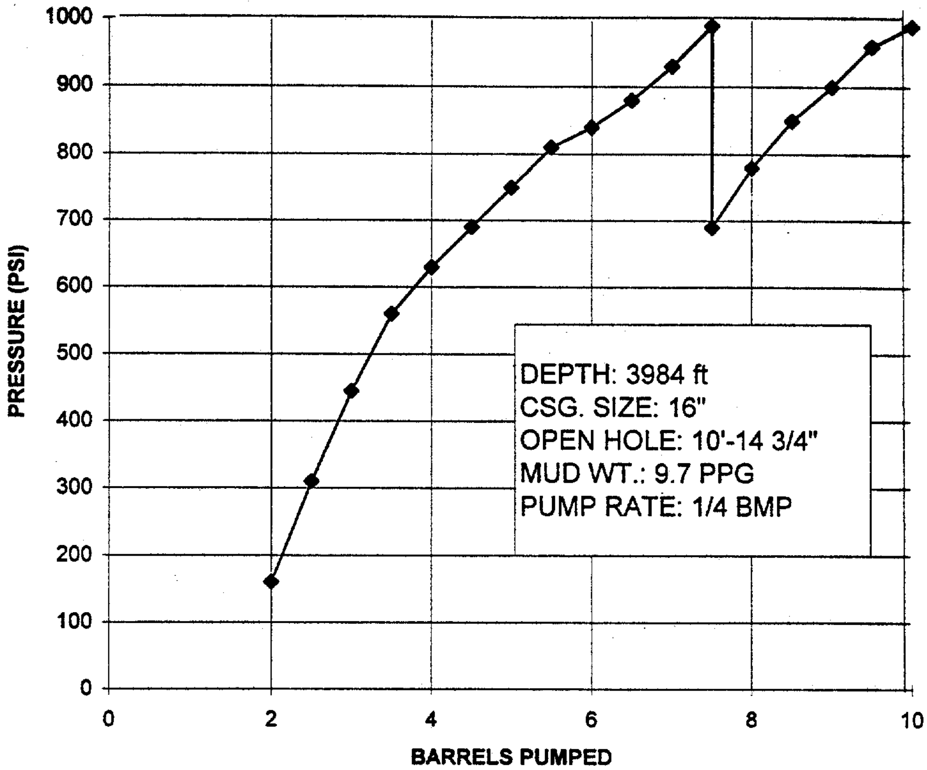


Figure 3. Nonlinear LOT in UMS with "yield" pressure



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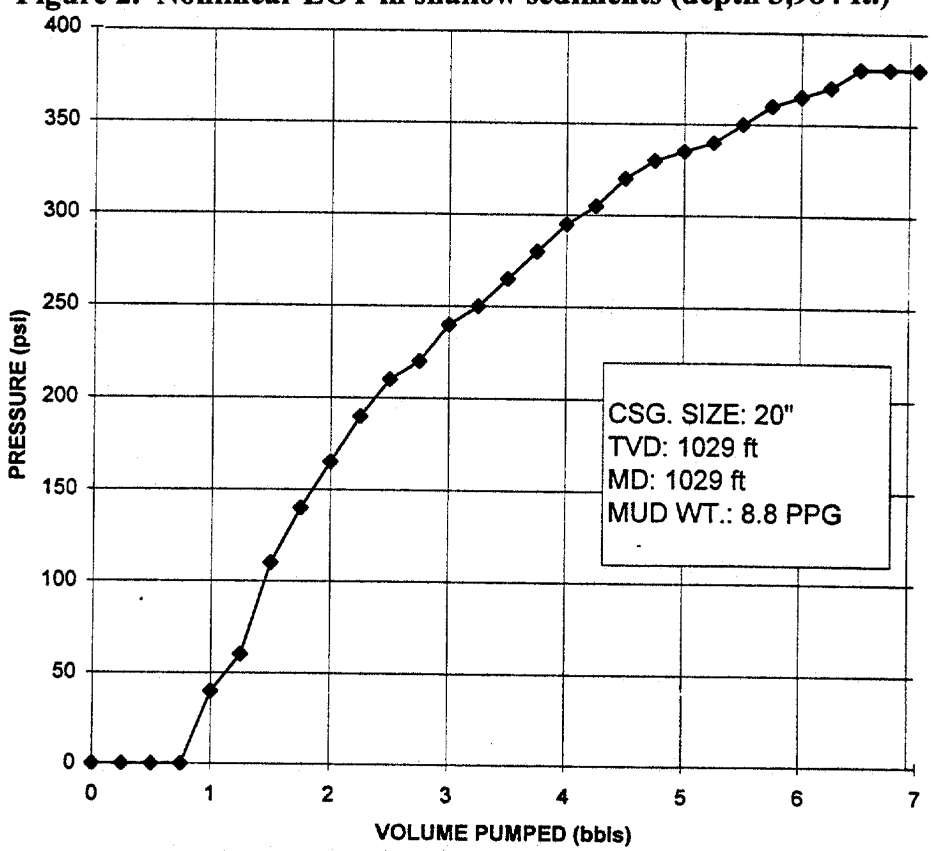


Figure 3. Nonlinear LOT in UMS with "yield" pressure

The pressure response depicted in Fig.3 is typical for LOT's in UMS. The plots may be different in the way their "yield" pressures behave. Rather than remaining constant, the yield pressure may slowly drop in a linear manner. Also, many operators have observed that the typical values of the yield pressure gradients are high and range from 0.75 psi/ft to over 1.0 psi/ft. This behavior is documented by data from five LOT's in UMS, shown in Table 1. The high pressure gradients indicate that UMS are much stronger than it has been previously believed. It was reported that for some shallow sediments fracturing gradients can become two-fold greater that those for deeper sediments.[1]

TABLE 1 - VALUES OF YIELD PRESSURE GRADIENTS FROM LOT's IN UMS

PROPERTY	UNIT	LOT 1	LOT 2	LOT 3	LOT 4	LOT 5
Water depth	ft	195	195	196	102	103
Shoe depth, BML	ft	218	534	747	583	582
Pressure @ yield	psi	185	170	380	155	220
Pump rate	bbl/min	5.00	5.00	0.25	0.25	0.25
Mud weight	lb/gal	8.65	8.5	8.8	9.0	8.9
Water gradient	psi/ft	0.44	0.44	0.45	0.44	0.44
Pressure gradient @ yield	psi/ft	1.49	0.84	1.02	0.829	0.94

One way of predicting the high strength of shallow sediments is to use equations from the theory of fracturing deep sediments, and make a empirical correlation between the ratio of vertical-to-horizontal stresses versus depth using data from LOT's. Though the approach may work in practical applications, it does not have a strong theoretical basis because it assumes that the sediments follow a pseudo-elastic model. Much testing has indicated that an elasto-plastic behavior is often seen. The approach may generate values of the stress ratio greater than one which are difficult to explain without considering the effects of some external factors such as tectonic stresses.

Generally, we believe that upper marine sediments are weaker and have higher stress ratios than deep sediments. They are also most likely to exhibit plastic rather than elastic behavior under stress loads applied by LOT's. Therefore, the conventional fracturing theory based on elastic analysis cannot fully explain either the behavior of UMS during LOT's or the potential damage resulting from these tests.

Potential Damage due to LOT

Typically, the incidents of shallow gas kicks or shallow water flows result from a loss of external borehole integrity. The loss causees flow behind cement which eventually develops into a continous and massive flow of these fluids upwards through the sediment outside the wellbore. This phenomenon, known as *cratering,* has been recently explained using several conceptual mechanisms of crater formation such as erosion of formation due to upward fluid flow, formation liquefaction, piping or caving[2]. The basic assumption in this current study was that all these mechanisms would originate from a channel or fracture outside the well which provided a conduit for pressurized fluids migrating from deeper formations. A conventional analysis of elastic vertical fracture was adopted to explain the initiation of this conduit.

The possibility exists that in the weak shallow sediments LOTs may induce mechanical damage around casing shoe that would provide a conduit for flow outside the well. Also, because the sediments are weak and plastic, the damage may be of three different kinds: tensile fracture, shear fracture, or annular channel.

Objectives and Method of This Work

The objective of this work is to examine the possible damage to the cement/formation interface during a LOT. Our presumption is that in UMS the formation around casing shoe is in plastic state which would determine stresses and deformations induced by LOT. Also, since the material fails in the plastic state, more than one (hydraulic fracturing) mechanisms of casing shoe damage may exist. One hypothetical mechanism arises from the magnitude of the radial plastic deformation around the shoe. If the deformation is large enough, it may initialize an annular channel that will be opened to mud invasion and propagate upwards. Another mechanism is formation of a shear fracture that would conically propagate to the sea bottom.

The methodology used in this reasearch involved a theoretical analysis based upon analytical modelling of the three dimensional state of stresses before and during LOT. The results of the analysis were verified in "simulated" experiments using the finite element software package ABAQUS. This approach is typical for solving complex mechanical problems when physical experimentation is difficult or results are inconclusive.

IN SITU STRESS IN UMS

Unlike for deeper formations (below 3,000 ft), no correlation of the UMS properties with depth exists for shallow sediments. Therefore, the problem is open to speculations. Many agree that upper marine sediments are soft and ductile compared to sediments at depth. Also, many maintain that "soft shales and unconsolidated sands frequently found in the Texas and Louisiana Gulf Coast can be considered to exist in a plastic state of stress[3]," or, "soft, clay-rich materials like shale often act as plastic,[4], or, "shallow marine sediment behaves plastic[2]. It is widely believed that these sediments may exist in both an elastic and a plastic state of stress. Therefore, whether or not a wellbore wall in UMS will turn into plasticity depends on the sediment properties. Also, it is not a rule that the wellbore wall in UMS is always in the plastic state while in a deep well it is in an elastic state. It is a well known fact that the deep sediments become ductile with depth and increasing stress.

Conventionally, the ratio of horizontal-to-vertical stress in situ has been used for determining fracture pressure gradient and interpreting leak-off test data. For an elastic state of stress and a laterally infinite sediment, the ratio is:

$$F_\sigma = \frac{\sigma_h}{\sigma_v} = \frac{\mu}{1-\mu}.$$

Typically, values of Poisson ratio measured at depth have been used to determine the stress ratio[5]. However, since the above relation is based on elastic theory, it is not suitable for sediments in a plastic state which typically show high in-situ values of stress ratio. To solve this problem, one may assume a 0.5 value of Poisson's ratio for UMS which results in a hydrostatic state of stress. However, since by its definition Poisson's ratio is a purely elastic constant, it does not pertain to sediment in a plastic state. Generally speaking, in plastic sediments Poisson's ratio calculated from the above equation (sometimes called the equivalent or effective Poisson's ratio) will be greater than its actual value for the sediment.

For an elasto-plastic sediment that is continuous, isotropic, homogeneous and obeys the linear Mohr-Coulomb criterion of perfectly plastic yield, the stress ratio in a plastic state is as follows:

$$F_\sigma = 1 - \frac{2(\sin\varphi + \frac{\tau_0}{\sigma_{zo}}\cos\varphi)}{1+\sin\varphi} \qquad (\sigma_{zo} \geq (\sigma_{zo})_{\lim}) \qquad (1)$$

where: $$(\sigma_{zo})_{\lim} = \frac{2(1-\mu)\tau_0\cos\varphi}{1-2\mu-\sin\varphi}.$$

Equation (1) indicates that plastic and elastic properties together control the stress ratio in UMS. Also, it can be shown that Eqn. (1) gives values of stress ratio different that one. The only situation when the ratio may become unity is for a frictionless sediment for which the Tresca yield criterion applies and the stress ratio is as follows:

$$F_\sigma = 1 - 2\tau_0/\sigma_{zo} \qquad \text{for,} \quad \sigma_{zo} > 2\tau_0(1-\mu)/(1-2u) \qquad (2)$$

Thus, the stress ratio approaches unity and the state of stress becomes seemingly "hydrostatic" when the UMS depth exceeds a few hundred feet and vertical stress becomes much greater than the cohesive strength.

It should be emphasized that these *in situ* stress relationships are valid only for sediments in a geostatic state. That is, horizontal stress is induced only by overburden pressure. The above formulas have been verified using the ABAQUS - simulated confined triaxial compressive tests with three different soft sediments. The simulated test results closely matched those calculated from Eqs.(1) and (2).

STATE OF STRESS AT CASING SHOE PRIOR TO LOT

Two major factors differentiate the distribution of stresses at the casing shoe in UMS and deep rocks. These factor are the effect of vertical stress and the presence of a plastic zone around the well. In this section, we will quantify the difference. In this analysis, we consider only effective stresses[6] (i.e., wellbore pressure is the difference between the actual wellbore pressure and formation pore pressure). Additional assumptions made included the following: (1) UMS is elasto-plastic and isotropic and (2) drilling mud is a non-penetrating fluid. In addition, our sign convention considers compressive and negative stress values as negative and positive, respectively.

Conventional models used for LOT analysis[9-14] and prediction of fracture gradients[8] are based upon two-dimensional elastic distribution of stresses around a hollow cylinder on plane strain as:

$$\sigma_r = \sigma_h - (\sigma_h - P_w)\frac{r_w^2}{r^2}$$
$$\sigma_\theta = \sigma_h + (\sigma_h - P_w)\frac{r_w^2}{r^2} \qquad (3)$$

The distribution is shown in Fig. 4. In the model, the effect of vertical stress is implicit in the value of horizontal stress.

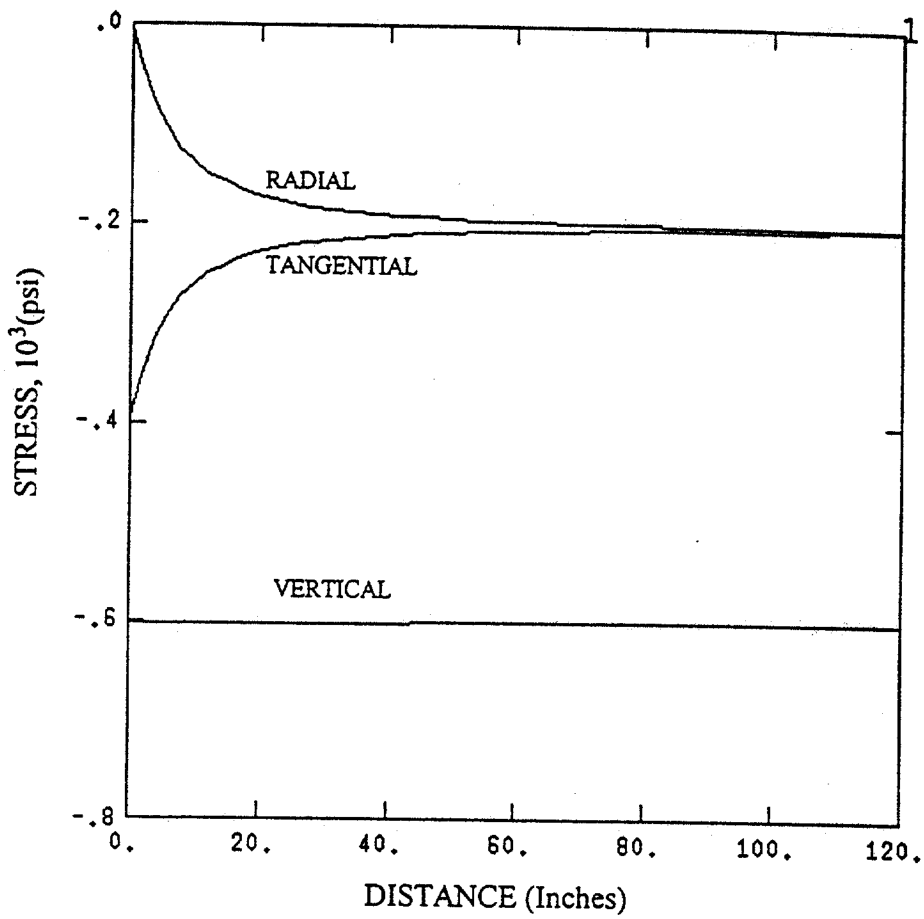


Figure 4. Plain strain elastic distribution of stresses around the borehole in strong rocks

Unlike in deep rocks, the presence of a well in UMS will result in two concentric zones of stress distribution. The plastic zone is adjacent to the well, and the elastic zone is adjacent to the plastic zone. This pattern has been discussed for various types of plastic sediments [15-17].

Distribution of stresses in these two zones is shown in Fig.5 [21]. The figure shows clearly that the size of plastic zone depends on the compressive strength of the sediment.

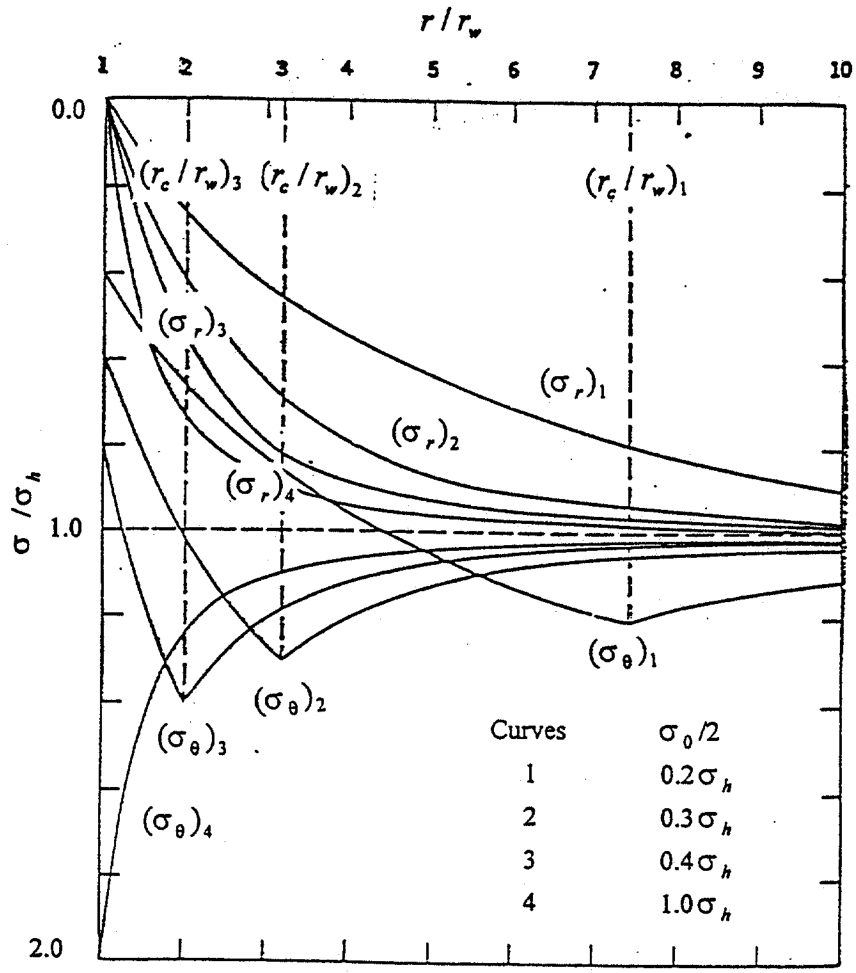


Figure 5. Elasto-plastic distribution of stresses around borehole in UMS: size of plastic zone[21]

The size of the plastic zone depends upon the properties of sediment and the yield criterion used. Shown in Fig. 5 are the sizes of the plastic regions around a shallow wellbore calculated using Tresca yield criterion. An estimation of the plastic zone size for UMS is based on the compressive strength values on the order of 10 to 100 psi as compared to deeper formations for which the compressive strength is on the order of 100 to 10,000 psi[22,23]. Assuming a one-foot hole in UMS having compressive strength 50 psi at a depth of 1,000 feet, the size of plastic zone is about 70 ft.

Based upon Mohr - Coulomb yield criterion, two-dimensional distribution of stresses in the plastic zone is described as:

$$\sigma_r = (P_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1}$$
$$\sigma_\theta = N(P_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1} \qquad (4)$$

where: σ_0 = unaxial compressive strength of sediment; and,

$$\sigma_0 = 2\tau_0 \cos\phi / (1 - \sin\phi) \qquad (5.1)$$

$$N = (1 + \sin\phi) / (1 - \sin\phi) \qquad (5.2)$$

Equations (4) imply that vertical stress is an intermediate stress. As such, it may not be considered. Many authors have made this simplification[7,15,16]. In fact, there are three principal stresses around the casing shoe and vertical stress is likely to become the largest of the three stresses in the plastic zone. Moreover, it is impossible to know if vertical stress is the largest stress without considering its distribution around the well. In this work, we add an expression for vertical stress to the stress model in Eqn. (4) as follows.

Vertical stress can be determined from Hooke's law by assuming that the only displacement outside the borehole is radial and that the only strain away from the well is the vertical one. Thus, for the case when vertical stress is smaller or equal to tangential stress; $\sigma_{\theta c} \geq \sigma_{zc}$, we have:

$$\sigma_z = \frac{E}{\lambda + G}\sigma_{z0} + \mu(\sigma_r + \sigma_\theta) \qquad (6)$$

Equations (4) through (6) constitute a pseudo 3-dimensional model of stresses outside plastic boreholes as shown in Fig. 6 for the case: $\sigma_{\theta c} \geq \sigma_{zc}$ (zone 0 - B). For the case: $\sigma_{\theta c} \prec \sigma_{zc}$ (zone B-C, in Fig. 6) more complex analytical expressions can be derived together with formulas for sizes of the two zones, r_b , and r_c [17]. Also, comparison of Figs. (5) and (6) clearly shows that the existence of the plastic zone dramatically reduces the concentration of stresses around boreholes.

Conditions for the largest stress:

The fact whether or not vertical stress is the largest stress in the plastic zone depends upon plastic properties of the sediment and in situ vertical stress. These conditions can be specified as follows:

If, $\mu \leq \dfrac{(1+N)\sigma_{z0} - \sigma_0}{(1+3N)\sigma_{z0} - \sigma_0}$ then, $\sigma_{\theta c} \geq \sigma_{zc}$

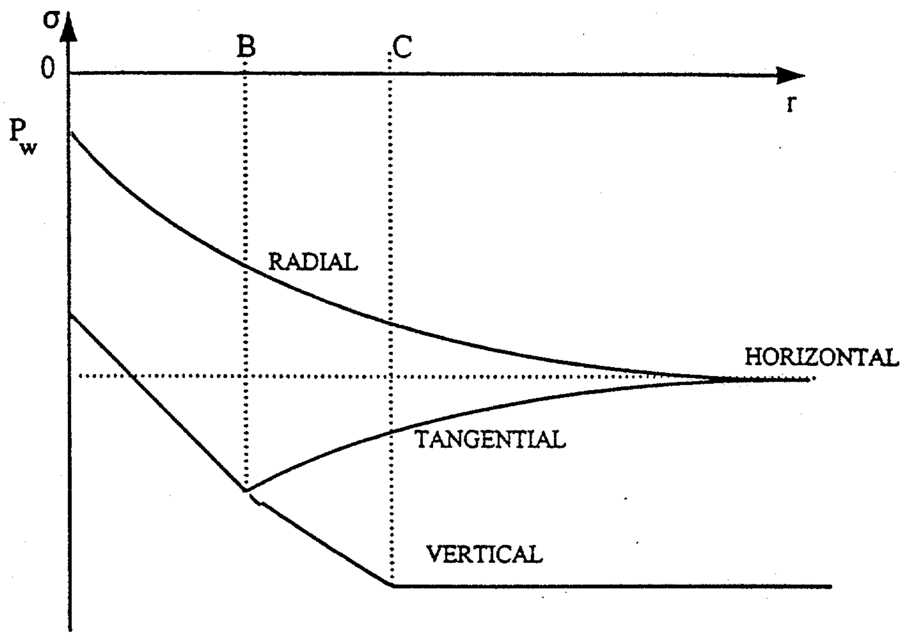


Figure 6. 3-D stress distribution around well shows two regions in plastic zone (0-B-C)

and $\sigma_{\theta c}$ is the largest stress at the plastic/elastic boundary [Equs. (4) - (6)].

If, $\mu \geq \dfrac{(1+N)\sigma_{z0} - \sigma_0}{(1+3N)\sigma_{z0} - \sigma_0}$ then, $\sigma_{\theta c} \leq \sigma_{zc}$

and σ_{zc} is the largest stress at the plastic/elastic boundary.

Conditions for plastic zone around wellbore:

By substituting the larger of the two stresses at the wellbore wall, $\sigma_{\theta w}$ or σ_{zw}, into the Mohr - Coulomb yield criterion, one can determine a required minimum value of wellbore pressure overbalance, P'_w, to eliminate the plastic zone around the well. If tangential stress at the wall is larger than vertical stress,

$$P'_w = \frac{2\sigma_h - \sigma_0}{1+N} \tag{7.1}$$

otherwise,

$$P'_w = (\sigma_{z0} - \sigma_0) / N \tag{7.2}$$

Our analysis of Eqns.(7) indicated that plastic zones exist around wells in UMS.

Verification with finite element simulation:

The conceptual distribution of stresses within the plastic zone around wellbore has been verified using several cases of wells in weak sediments simulated with the finite element software. Two examples of stress distributions are shown in Figs. (7) and (8). Depicted in Fig. 7

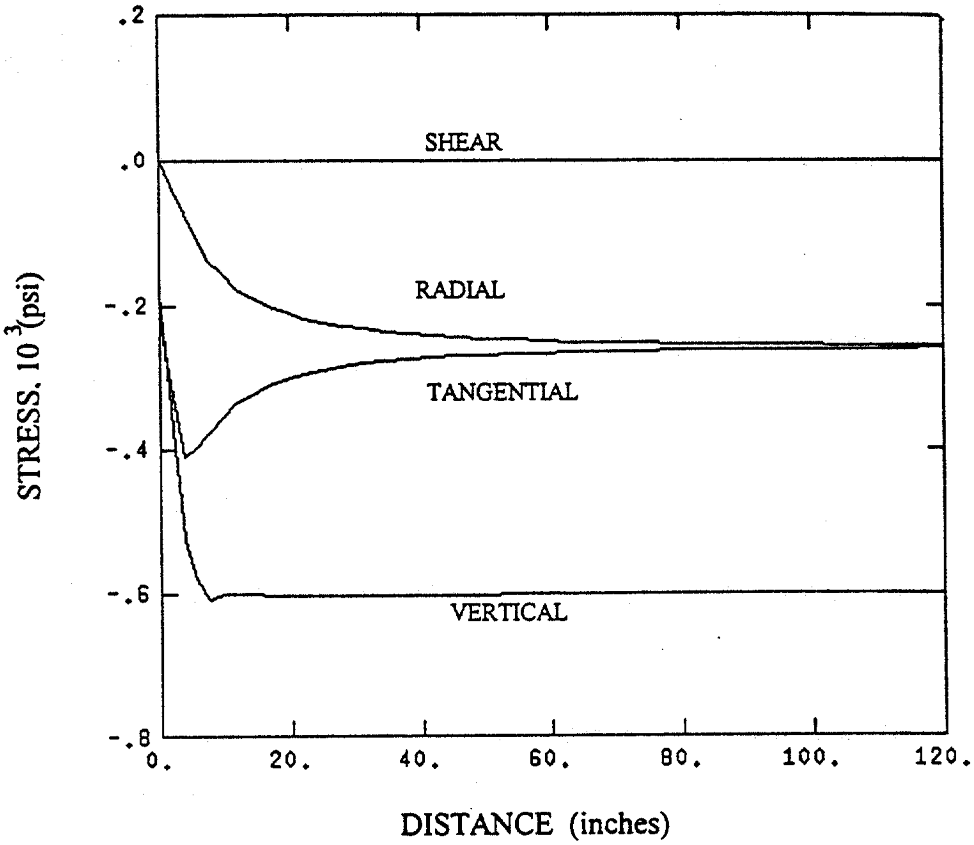


Figure 7. Distribution of stresses in plastic zone around well prior to LOT (Case 1)

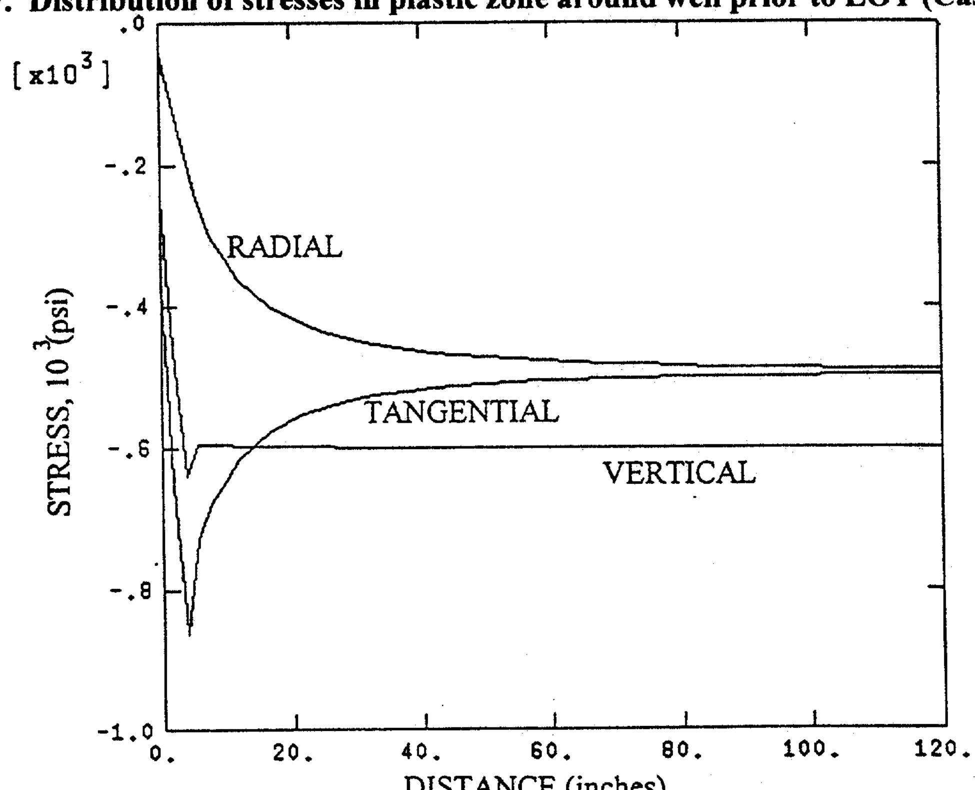


Figure 8. Distribution of stresses in plastic zone around well prior to LOT (Case 2)

is the case when plastic zone consists of two regions. In the outer region vertical stresses dominate (case: $\sigma_{\theta c} \le \sigma_{zc}$) while in the inner region vertical and tangential stresses are practically equal. Complex analytical formulas or finite difference simulations apply to this case[17]. Figure (8) depicts a case when tangential stress dominates in the plastic zone around wellbore. In this case stress distribution can be calculated from simple formulas in Eqns. (4) through (6).

LOT INDUCED FRACTURES IN UMS

During LOT an additional pressure, ΔP_w, is added to wellbore pressure. Stresses around a wellbore are calculated by superimposing the existing stresses before LOT and the new incremental stresses added by LOT. Stress distribution within the plastic zone for the case: $\sigma_{\theta c} \ge \sigma_{zc}$, is as shown:

$$\begin{aligned}
\sigma_r &= (P_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1} + \Delta P_w \frac{r_w^2}{r^2} \\
\sigma_\theta &= N(P_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1} - \Delta P_w \frac{r_w^2}{r^2} \\
\sigma_z &= \frac{E}{\lambda + G}\sigma_{z0} + \mu(\sigma_r + \sigma_\theta)
\end{aligned} \tag{8}$$

Equation (8) implies that LOT would increase radial stress, reduce tangential stress, and leave vertical stress unchanged. Similar to Eqn.(8), an alternative mathematical model of stresses has been derived for the case: $\sigma_{\theta c} < \sigma_{zc}$.. Our calculations performed for UMS using the above model indicate that reduction of tangential stress from compression to tension requires a relatively small increase of wellbore pressure up to about 200- 300 pounds.

Tensional fracture initiation and propagation

Since the UMS tensional strength is relatively small and is sometimes regarded as zero it is assumed here that the wellbore will be fractured when P_w is zero or very small. Thus, the fracture condition is $\sigma_\theta = S_{ten}$, or:

$$P_{wlot}^{non} = (N+1)P_w + \sigma_0 - S_{ten} \tag{9}$$

Strictly speaking, when Eqn.(9) is satisfied the fracture occurrs only at the wellbore surface, and it cannot propagate because of increasing tangential stress as shown in Figs.7 and 8. Thus, to make the fracture propagate, wellbore pressure must be increased. Consequently, the leak-off pressure in Eqn. (9) is called the non-propagating fracture pressure.

As the LOT pressure increases, the fracture propagates outwards. At the boundary of the elastic zone ($r = r_c$) the fracturing pressure is:

$$P_{wlot}^{max} = \frac{2N}{1+N}\sigma_h + \frac{1}{1+N}\sigma_0 + P_w - S_{ten} \tag{10}$$

LOT pressure in Eqn.(10) is a maximum fracturing pressure indicating the stress concentration region and the onset of fracture propagation similar to the formation breakdown pressure in the hydraulic fracture stress test procedures for elastic rocks. At this pressure, the fracture passes the point with the maximum value of tangential stress. The stress concentration rato at this point is as follows:

$$F_{con} = \frac{2N}{N+1} + \frac{\sigma_0}{(N+1)\sigma_h} \tag{11}$$

The value calculated from (11) for plastic zone corresponds to the value of two for elastic rocks. After passing the stress concentration region the fracture propagation pressure can be expressed in a conventional way as:

$$P_{wlot}^{pro} = \sigma_h + S_{ten} \tag{12}$$

For the case when vertical stress is the largest one in the plastic zone ($\sigma_{\theta c} < \sigma_{zc}$), a duplication of the above procedure would result in a complex analytical procedure requiring calculating sizes of the two regions depicted in Fig. 6. However, simplified alternative method can be developed. The method, beyond the scope of this writing, is based upon an observation depicted in Fig.6 . For $r < r_b$, tangential stress is almost equal to vertical stress. Hence, the values of tangential stress can be used instead of the vertical stress values in the Mohr-Coulomb yield criterion in this region.

Verification of fracturing pressures with finite element tool:

The results of finite element analysis have been compared with the analytical results. Shown in Table 1 are seven cases of sediment properties and LOT pressure values. In the table, σ_{wlot}^{non} and σ_{wlot}^{max} are the tangential stresses corresponding to the non-propagation pressure and the maximum fracture pressure from finite element analysis. The maximum facture pressure is determined by assuming that the drilling fluid instantly enters the non-propagating fracture.

TABLE 2 FRACTURE PRESSURES FROM ANALYTICAL AND FINITE ELEMENT MODELS

CASE	σ_v	σ_h	ϕ	σ_0	μ	P_w	ANALYTICAL P_{wlot}^{non}	ANALYTICAL P_{wlot}^{max}	ABAQUS σ_{wlot}^{non}	ABAQUS σ_{wlot}^{max}
1	600	257	25.4	100	0.3	0	100	364	195	405
2	600	491	25.4	100	0.3	50	275	711	415	915
3	600	257	25.4	100	0.3	50	275	414	----	-----
4	900	600	45	200	0.4	0	200	973	1200	1200
5	900	600	15.3	200	0.4	0	200	776	282	845
6	1100	900	29.8	100	0.45	0	100	1231	135	1500
7	1100	900	35.5	100	0.45	0	100	1291	1800	1800

It is clear from Table 2, that the values of non-propagation pressures calculated from these two models are quite different. According to the analytical model (Mohr-Coulomb criterion), there are plastic zones around wellbores for all cases considered. However for Case 4, the finite element model indicates that the wellbore is still in an elastic state. The difference can be attributed to a different treatment of intermediate stress by the two models. Drucker-Prager criterion which is used in the finite difference model considers the effect of intermediate stress but Mohr-Coulomb does not. Fortunately, the discrepancy can be largely eliminated by introducing a simplified Drucker-Pragar criterion. The simplification is made by assuming that the maximum stress is equal to the intermediate stress. This assuption is quite justified in view of the closeness of the values of vertical and tangential stresses as shown in Figs. 6, 7, and 8. The material constants N, and σ_0 in the Mohr- Coulomb yield criterion become: N_D, and σ_{0D}, as:

$$N_D = \frac{3+\sin\phi}{3-5\sin\phi}; \quad \sigma_{0D} = \frac{6\tau_0\cos\phi}{3-5\sin\phi}$$

and Mohr-Coulomb criterion is as follows:

$$\sigma_1 - N_D\sigma_3 = \sigma_{0D} \tag{13}$$

In essence, this simplification involves modification of the Mohr-Coulomb criterion shown in Eqn.(13), and the derivation gives the same analytical model as presented above. The modified analytical model gives results similar to those from the finite difference model. A comparison of these results is shown in Table 2 along with results obtained using conventional Mohr-Coulomb and Tresca criteria. The improvement is quite obvious.

TABLE 3 VERIFICATION OF ANALYTICAL RESULTS USING FINITE ELEMENT MODEL

	CASE1	CASE2	CASE3	CASE4	CASE5	CASE6	CASE7
TRESCA	100 307	200 591	200 357	200 700	200 700	100 950	100 950
Mohr-C	100 364	275 711	275 414	200 973	200 776	100 1231	100 1297
Sim. D-P	200 444	451 858	451 494	--- ---	263 974	293 1497	1260 1745
ABAQUS	195 405	415 915	-- ---	1200 1200	282 845	135 1500	1800 1800

Eventuality of tensional fractures in UMS:

Shown in Figs. 9, and 10 are stress distributions around the well for Case 1 for two values of LOT pressures, 250 psi, and 600 psi, respectively. At 250 psi, tangential stress at the well reduces to zero. As the LOT pressure increases, the stress value returns to compression indicating that the sediment yielded for the second time. Thus, stresses imposed by LOT on a plastic wellbore may cause a second yield instead of tensional fractures. The phenomenon can be explained as follows. As LOT pressure increases, differential stress (difference between radial and tangential stresses) decreases, and the wellbore wall undergoes a change from a plastic state (resulting from drilling) to an elastic state (resulting from LOT). As the LOT pressure continues to increase, differential stress starts increasing again, and the rock reaches conditions of plastic yield for the second time. As shown in Figs. 9, and 10 the second yield may happen before the wall goes into tension and fractures. The LOT pressure required to induce the second yield can be expressed as follows:

$$P_{wlot} = NP_w + \sigma_0 \tag{15}$$

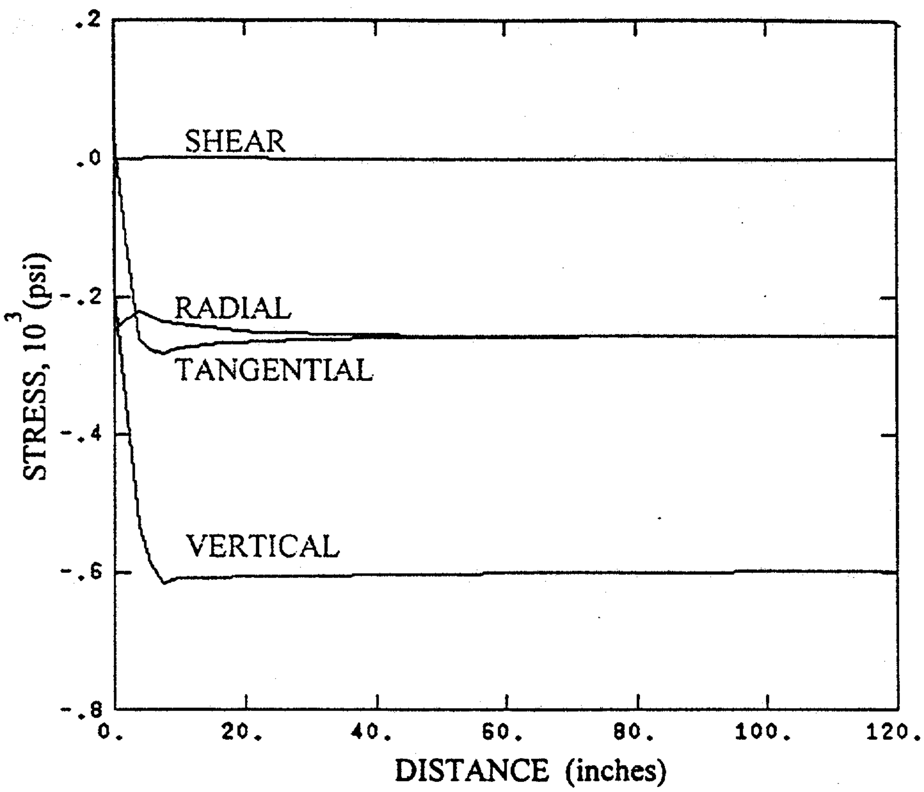


Figure 9. Reduction of tangential stress due LOT (250 psi) for Case 1

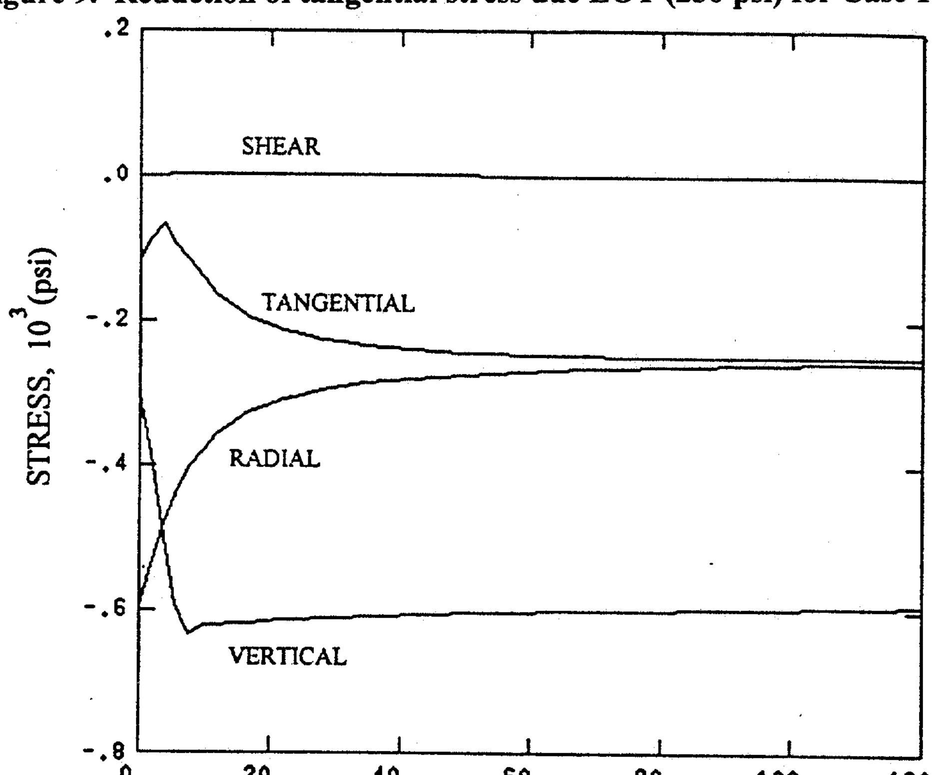


Figure 10. Reversal (second yield) of tangential stress due to LOT (600 psi) for Case 2

At this pressure, tangential stress at the wellbore wall is: $\sigma_\theta = P_w$; where P_w is the wellbore pressure prior to LOT. For conventional overbalance drilling operations, $P_w > 0$, and tangential stress can not be reduced to tensile stress. Theoretically, the increasing LOT pressure may not fracture the well.

LOT-INDUCED ANNULAR CHANNELS IN UMS

As discussed above, increasing LOT pressure does not induce fractures. Instead, it would cause plastic deformation of the open hole. Typically, plastic deformations are larger than elastic deformations and must be considered in the stress analysis. Also, the analytical analysis presented above is valid only for the mid-section of the open hole and therefore becomes unsuitable for analysis of deformations along the whole open hole section. In order to overcome these limitations of the analytical modelling, further analysis was performed using the finite element method.

As the wellbore pressure increases, both the plastic zone around the wellbore and the wellbore radius increase. Radial deformation of the wellbore wall is greater than that of the cement and casing so an annular channel may be initiated at the casing shoe. Shown in Fig. 11 is the deformation of a 10 - foot open hole below the casing shoe for Case 1 in Table 2 where the LOT pressure increased from zero overbalance to 500 psi.

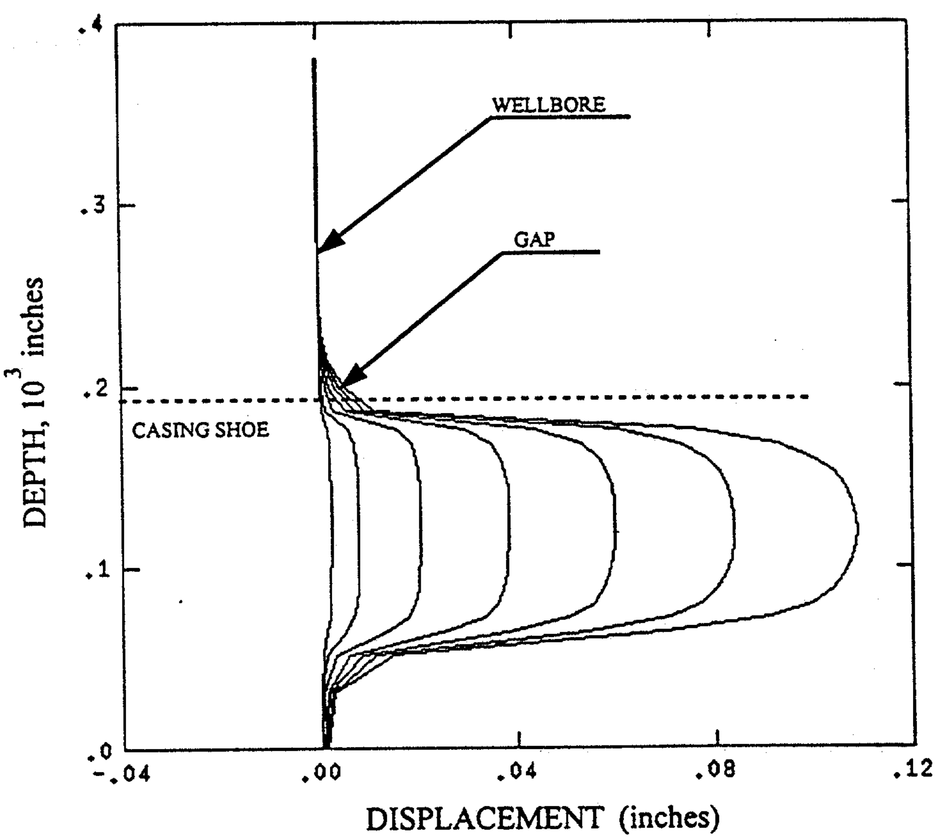


Figure 11. Deformation of open hole at casing shoe during LOT

There is an evident gap created at the casing shoe. The size of the gap can be of the order of 0.01 in. to 0.1 in. and is dependent upon LOT pressure and the size of plastic zone around the well. A possible inflow of drilling mud into the gap depends upon the gap size and pressure differential across the gap. A minimum-entry size gap for most drilling fluids is in the range from 0.01 to 0.15 in. Thus, the deformation created by LOT is sufficiently large for drilling mud to enter and pressurize the gap. Once in the gap, the drilling mud will induce pressure upon the newly opened rock surface and propagate the annular channel. A conceptual propagation of such a channel is shown in Fig. 12.

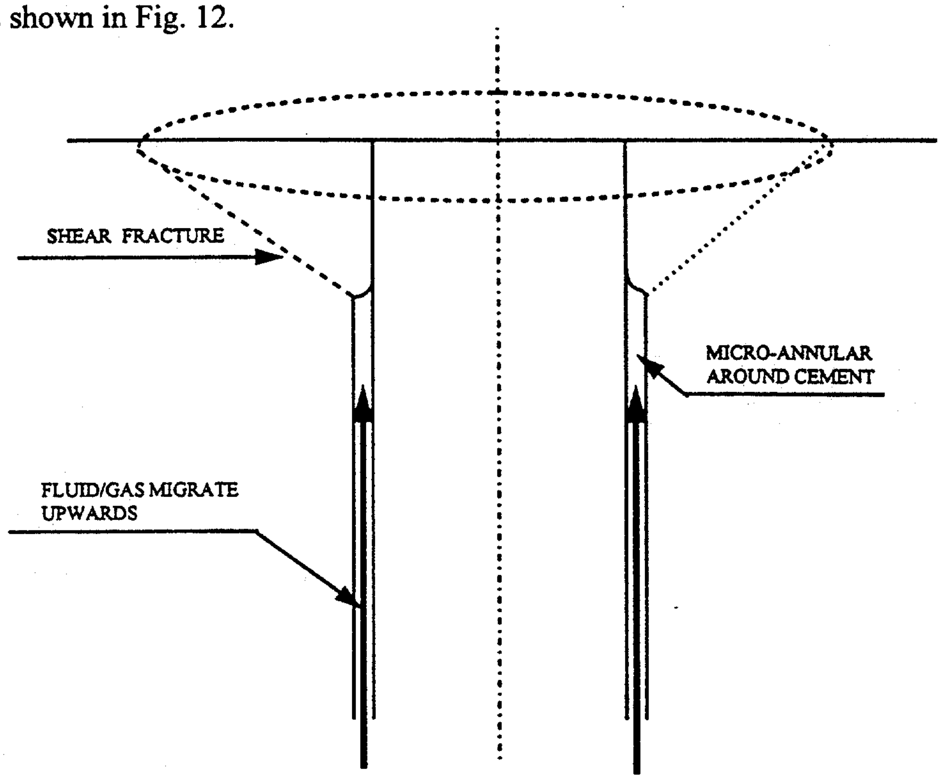


Figure 12. Conceptual propagation of annular channel during LOT

Critical conditions for propagation of annular channels can be determined from the difference between the pressure at the top of mud in the channel and the pressure at casing shoe. Pressure at the top of the mud channel is:

$$P_{wlot}^{top} = P_{wlot}^{shoe} - (\Delta P_{mud} - \Delta P_{pore}) \tag{14}$$

Theoretically, an annular channel should propagate upwards only if the wellbore pressure at the casing shoe increases. As a result, the LOT pressure plot should stabilize at some constant value of pressure. (Small variations are possible, however, due to frictional pressure losses and filtration.) A conceptual plot of LOT pressure for such situation is shown in Fig. 13. It should be pointed out, however, that a similar shape of the LOT curve may be obtained for a horizontal fracture.

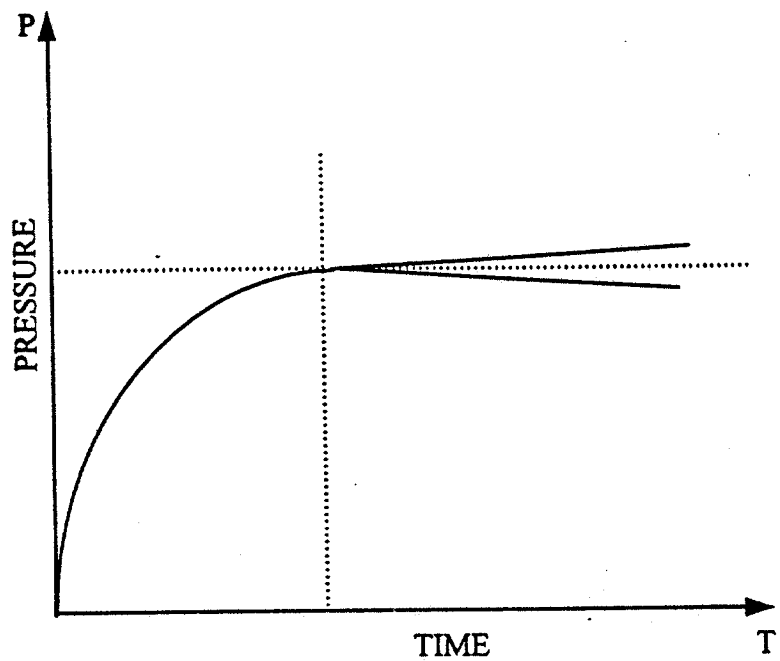


Figure 13. Conceptual shape of LOT plot in UMS

LOT-INDUCED SHEAR FRACTURES IN UMS

As shown in Fig. 14, there are two areas of shear stress concentration in the open hole. One is at the casing shoe and the other is at the bottom of the hole. Therefore, a possibility exists for initiation of a shear fracture. However, considering ductility of UMS, a shear fracture will be unlikely to propagate at depth. A shear crack would not open to mud invasion because the borehole wall is compacted by wellbore pressure. The only alternative for a shear fracture to open and propagate is at a very shallow depth as shown in Fig. 12. Theoretically, an annular channel advancing upwards may eventually create a shear fracture that would conically propagate to the surface.

A conical shear contour has been simulated with the finite element software as shown in Fig. 15. Numerical analysis indicated that a surface-bound shear fracture is limited by a critical depth at which the fracture originates. This critical depth depends upon the shear strength of the sediment and the pressure at the top of the annular channel.

CONCLUSIONS

The following conclusions can be made based upon this project progress to date:

1. Of the three possible borehole failures caused by LOT in UMS the most likely one is formation of an annular channel ouside the well cement; The channel may propagate upwards at a constant bottomhole pressure.

2. It is very unlikely that LOT may induce vertical fractures in UMS.

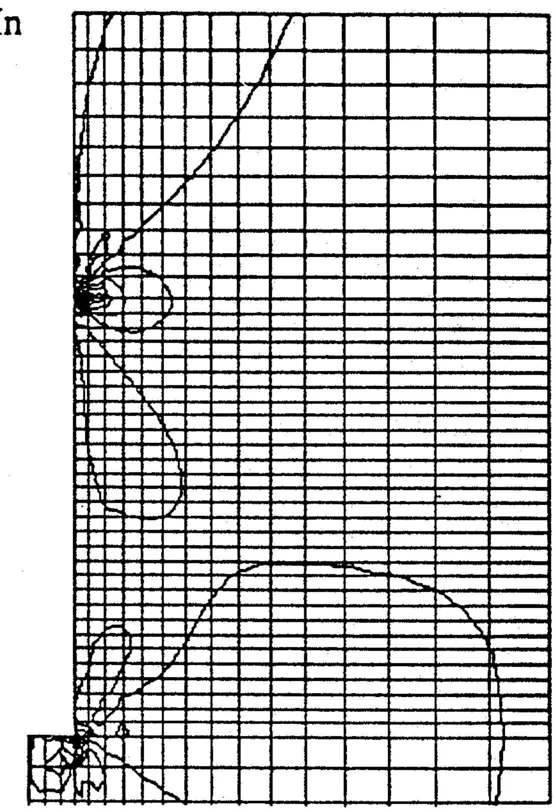
3. Preliminary results of finite element analysis indicate that initiation of horizontal fractures due to LOT is doubtful because vertical stress seems little reduced by increasing LOT pressure. More work is needed, however, to understand this effect.

4. There is a critical depth of UMS at which the propagating annular channel may develop into a conical shear fracture that would break to the surface. The critical depth can be predicted from UMS properties.

5. A horizontal-to-vertical stress ratio of UMS is different than unity and can be determined with the model developed in this work.

6. Using an analytical method, developed in this work, stress distribution in the plastic zone around boreholes in UMS can be calculated. These calculations, however, are restricted only to the mid-section of the open hole below casing shoe.

250 In



120 In

Figure 14. Two areas of two areas of shear stress concentration in the open hole

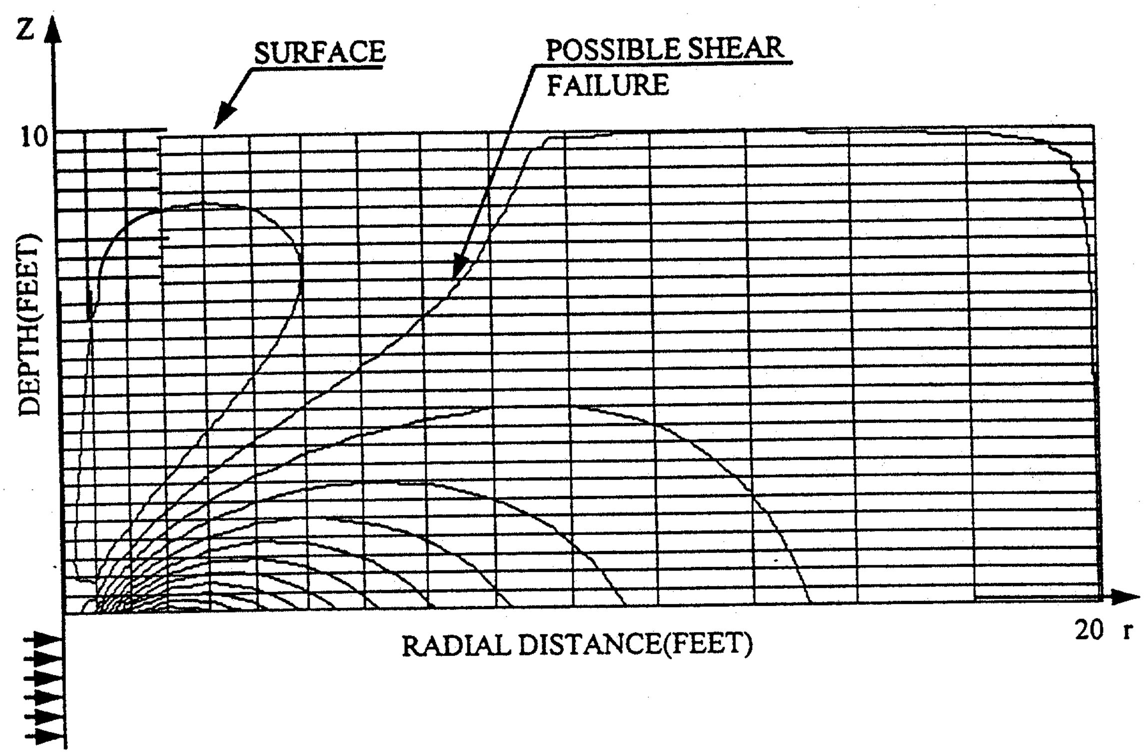


Figure 15. Contour map of shear stresses with trajectory of possible fracture to surface

NOMENCLATURE

E = Young's modulus

F_{con} = ratio of maximum tangential stress to far-field horizontal stress

F_{σ} = ratio of horizental to vertical stresses

N = rock property constant

P_{wlot} = leak-off pressure (difference between leak-off pressure and formation pressure)

P_{wlot}^{shoe}, P_{wlot}^{top} = P_{wlot} at the top of the mud and the casing shoe.

P_w = initial wellbore pressure (difference between wellbore pressure and formation pressure)

P'_w = critical wellbore pressure

r = radial distance from the wellbore center line

r_c = boundary between elastic and plastic zones

r_w = wellbore radius

$\sigma_0 =$ uniaxial compresive strength

σ_1, $\sigma_3 =$ maximum and minimum stresses

$\sigma_h =$ far-field horizontal stress

$\sigma_{z0} =$ far-field vertical stress

σ_r, σ_θ, $\sigma_z =$ radial, tangential, and vertical stresses around a wellbore

σ_{rc}, $\sigma_{\theta c}$, $\sigma_{zc} =$ stresses at the boundary between elastic and plastic zones

σ_{rw}, $\sigma_{\theta w}$, $\sigma_{zw} =$ radial, tangential and vertical stresses at wellbore

τ_0, $\phi =$ cohesive strength and the angle of friction

$\mu =$ Poisson's ratio

ΔP_{mud}, $\Delta P_{pore} =$ pressure difference between mud and pore fluid at the casing shoe and top of the annular channel, respectivelu

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Density, Strength and Fracture Gradients for Shallow Marine Sediments

by Chris Sandoz and Adam T. Bourgoyne, Jr., LSU

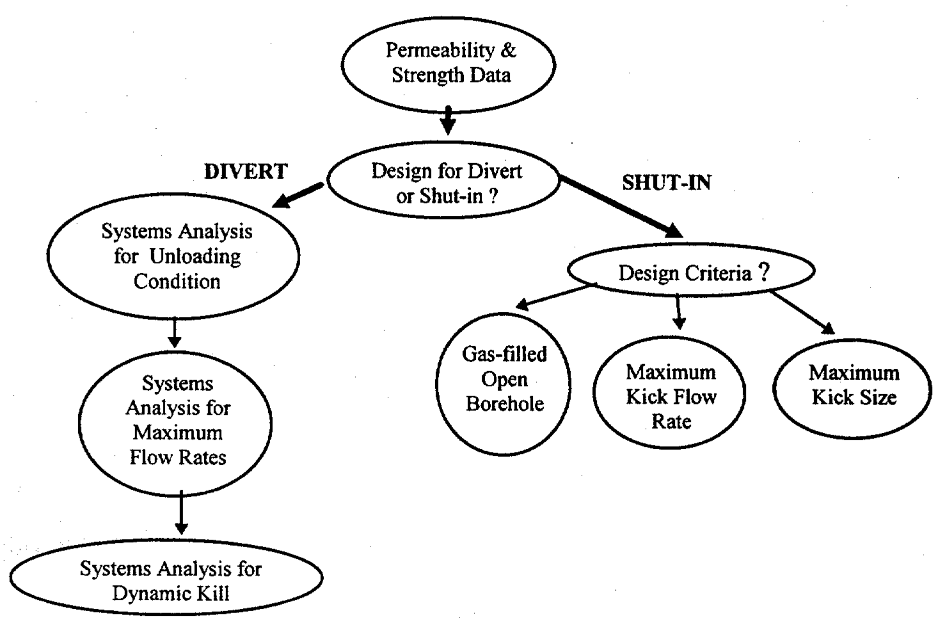
INTRODUCTION

Flow from an unexpected shallow gas sand is one of the most difficult well control problems faced by oil and gas well operators during drilling operations. Current well control practice for bottom-supported marine rigs usually calls for shutting in the well when a kick is detected if sufficient casing has been set to keep any flow underground. However, when shallow gas is encountered, casing may not be set deep enough to keep the underground flow from broaching to near the platform foundations. Once the flow reaches the surface, craters are sometimes formed which can lead to loss of the rig and associated marine structures.

The sediment failure mechanisms that lead to cratering have been poorly understood. In addition, there has been considerable uncertainty as to the best choices of well design parameters and well control contingency plans that will minimize the risks associated with a shallow gas flow.

Sediment strength is one of the most important factors in designing the shallow casing of a well. To prevent breaking down the shallow sediments, diverter operations may be employed. However, a recent study by Rocha and Bourgoyne shows that diverter systems may also cause cratering. Therefore, sediment strength is also integral in determining proper the well control procedure, i.e., whether to shut-in or divert the well. Figure 1 shows a generalized decision tree for shallow casing design.

Figure1 - Decision Tree for Shallow Gas Design



effect of pore pressure vanishes and fracture pressure becomes equal to the overburden pressure.

Overburden Pressure

The overburden pressure is the most important parameter affecting fracture pressure. The overburden pressure at a certain depth can be thought of as the pressure resulting from the total weight of the rock and pore fluids above that depth. Since bulk density is a measure of the weight of rock and pore fluids, the overburden pressure at a certain depth can be easily calculated by integration of the bulk density versus depth profile. For offshore sediments, hydrostatic pressure due to water depth must also be considered.

The best source of bulk density data is from in-situ measurements made with a gamma-gamma formation density log. Unfortunately, such data is seldom available for depths less than the surface casing setting depth. Accuracy of formation density logs can be poor in large diameter holes, so that a pilot hole may be required to get good measurements in the shallow sediments. This will often not be cost effective.

Use of Soil Borings Data

Louisiana State University is involved in an ongoing study to develop improved correlations for estimating the break-down resistance of upper-marine sediments using soil borings data. This information can be used to help fill-in some of the missing data needed in designing the shallow portion of the well. A number of tests are routinely run on soil borings by geotechnical engineers to determine the load bearing capacity of the shallow sediments. The physical properties tested generally fall into one of three categories:

1) weight/density measurements,
2) Atterberg limits, and
3) shear strength measurements.

Weight/density measurements include moisture content, wet unit weights, and dry unit weights. Atterberg limits tests measure plastic limits and liquid limits of the soil. Shear strength measurements are done with miniature vane, Torvane, Remote vane, Cone Penetrometer (CPT), and triaxial shear tests.

Geotechnical data for shallow sediments is normally collected during platform site surveys. The geotechnical data contains information on various soil properties including soil density and strength. Soil density from the geotechnical data can then be used to find overburden pressure which, at shallow depths, should be close to the fracture pressure of the sediment. Comparisons between the actual leak-off test pressures from the database

CONCLUSIONS

Better characterization of shallow marine sediments is important for creating improved shallow casing designs. Soil borings can be used to provide the missing information necessary for these designs to be successful. We are interested in obtaining additional shallow leak-off test data and corresponding soil borings data to continue this study. Anyone interested in providing field data to this ongoing research project are encouraged to contact the authors. Leak-off test charts, soil borings data, and density log data for sediment depths of less than 3000 ft (1000 m) below the mudline are needed.

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Estimating break-down pressure of upper marine sediments using soil boring data

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overlying sediments can open a flow path to the surface. Thus, for some sedimentary sequences, diverters cannot insure that cratering will not occur.

The above concerns have led the authors to re-examine the design parameters for shallow casings in order to determine when shutting-in a shallow kick is permitted. Arifun and Sumpeno (1994) with Unocal Indonesia have indicated that wells are being designed assuming shut-in from surface to total depth in their East Kalimantan operations.

For either shut-in or diverter operations, sediment strength and permeability are key parameters in the design of a shallow casing. In most areas, well log data are not available for the shallow sediments. This paper describes how data from soil borings can be used to help fill-in some of the missing data needed in designing the shallow portion of the well. Example data from the Green Canyon area of the Gulf of Mexico are used to illustrate the recommended approach. Soil boring data are integrated with deeper well log data to provide a more accurate estimate of overburden stress and formation break-down pressure.

2. Background information

2.1. Review of sediment failure criteria

The effective vertical matrix stress (intergranular pressure) is an important parameter controlling sediment failure during well control operations. The effective matrix stress, σ_z, is defined by:

$$\sigma_z = s - p_p \tag{1}$$

where s is the total overburden stress and p_p is the formation pore pressure.

In recent work, Rocha (1993) used Mohr–Coulomb failure criteria (Fig. 1) to help visualize the various sediment failure mechanisms leading to the formation of a crater during well control operations. In Fig. 1, the Mohr's Circles define the state of stress at various depths in the region of the borehole.

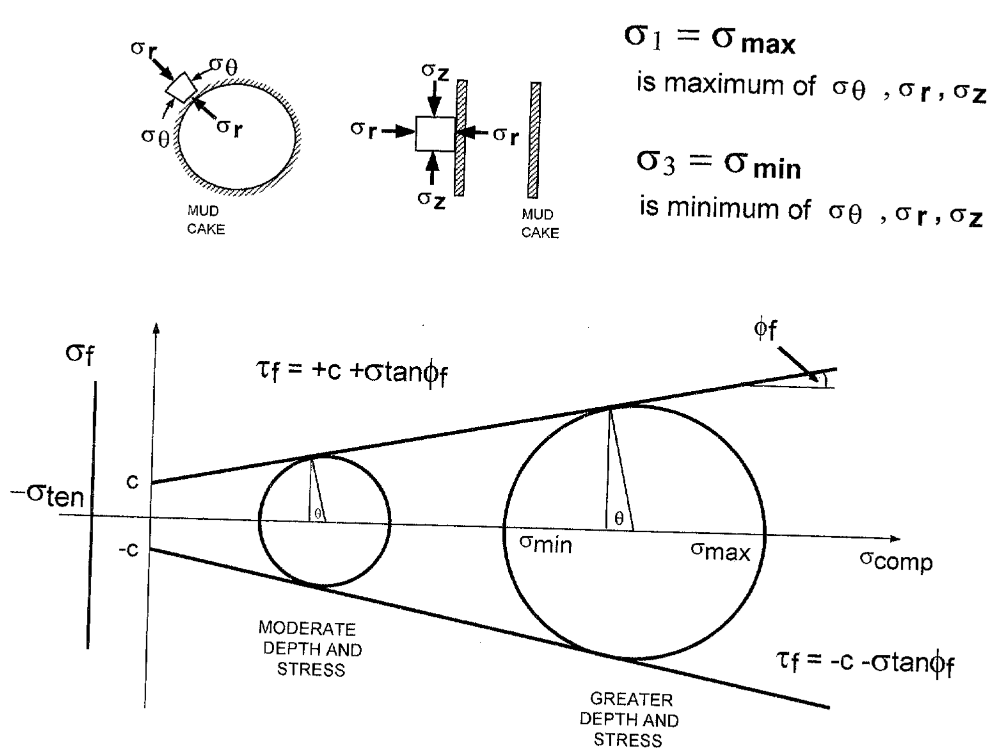

Fig. 1. Mohr–Coulomb failure criteria based on total stresses.

Minimum and maximum principal effective stresses (σ_{min} and σ_{max}) are labelled in Fig. 1. Sediment failure is predicted to occur whenever a Mohr's Circle touches one of the failure lines given by:

$$\sigma_f = -\sigma_{ten} \tag{2a}$$

$$\tau_f = \pm c \pm \sigma \tan(\phi_f) \tag{2b}$$

When the Mohr's Circle touches the tensile strength line, σ_f, a hydraulic fracture type failure occurs. This is the usual failure mode during well control operations for deeper sediments, and the hydraulic fracture orientation is generally near vertical.

When the Mohr's Circle touches a shear strength line, τ_f, a shear type failure occurs. The shear failure begins with the formation of numerous micro-cracks that can be followed by linking and propagation of the micro-cracks to form a gouge zone. The reduced tensile strength and increased permeability associated with the formation of microcracks is believed to sometimes cause the shear failure-mode to change to a tensile failure-mode.

Fig. 1 indicates that the angle of internal friction is the slope of failure criteria line. Deep unfractured rocks that are well cemented have a high value of cohesion, c, and a high angle of internal friction, ϕ_f, of about 30°. In this case, the shear strength and compressive strength increase as the confining stress increases with increasing depth. Additionally, tensile strength is usually very low compared to the maximum effective stress, σ_{max}, and compressive strength, σ_{comp}. The tensile strength will be zero if natural fractures are already present. In well design practice, sediment tensile strength is usually assumed to be zero.

Marine sands near the surface that contain little or no clay are usually cohesionless ($c = 0$) and have no tensile strength ($\sigma_{ten} = 0$). Failure of these sediments during an underground blowout can lead to formation liquefaction (fluidization). This occurs when the vertical pore pressure due to flow of formation fluids in the sand reaches or exceeds the static effective vertical stress present prior to the underground blowout.

Shallow marine clays not only have low cohesion and tensile strength, but also have a low angle of internal friction (McClelland, 1969). Shallow formations found in many areas of the Gulf of Mexico are predominantly marine clays. Shallow marine clays tend to behave such that the effective matrix stress in the horizontal direction essentially equals the vertical matrix stress. In shallow plastic formations, the sediment failure mechanism may not be a true hydraulic fracture. A shear stress failure followed by seepage and tunnelling-type erosion is believed to be a possible mode of failure. Failure modes in which flow through the sediments occurs in pipe-like channels have been documented extensively in the geotechnical literature concerning failure of earthen dams. Exit holes in the seafloor consistent with piping-type channels have also been observed during underground blowouts using remote cameras and divers.

2.2. Stress concentrations around the borehole

The *initiation* of sediment failure in a wellbore can occur at a higher pressure than is required for fracture *propagation*. To initiate a vertical fracture, horizontal stress concentrations present near the borehole wall must be exceeded. Some of the horizontal stress previously carried by the rock that was removed by the bit must be borne by the remaining rock. Additionally, mud is generally present in the well when sediment failure is initiated, and thus permeable zones are always covered by a filter cake. Consequently, the wellbore fluids do not easily penetrate the borehole walls as the pressure is increased above the pore pressure.

Shown in Fig. 2 is a plot of the horizontal stress as a function of distance from the wellbore wall for the case of uniform horizontal stress. This calculation is presented by Hubbert and Willis (1957) for the case of elastic rock behavior and a smooth and cylindrical borehole with axis parallel to a principal stress. The stress concentration near the wellbore results in a horizontal effective stress twice that of the undisturbed (far-field) effective horizontal stress.

The principal stresses present at the borehole wall for a non-penetrating fluid, uniform horizontal stress, and elastic rock behavior are given by Rocha (1993):

$$\sigma_{rw} = p_w - p_p \tag{3a}$$

$$\sigma_{\theta w} = 2\sigma_h + p_p - p_w \tag{3b}$$

$$\sigma_{zw} = \sigma_z \tag{3c}$$

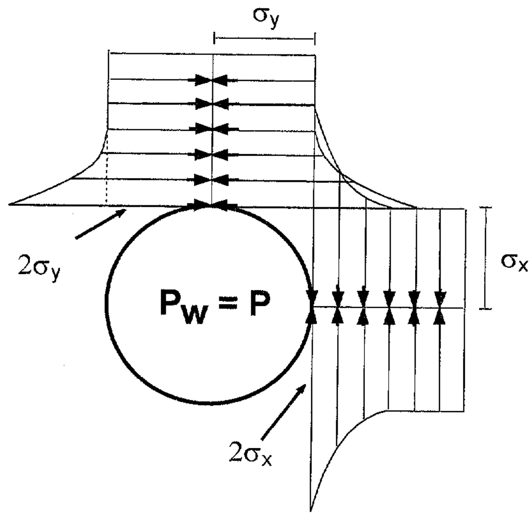

Fig. 2. Stress concentration around the borehole.

Eq. 3b predicts that a vertical hydraulic fracture is initiated when the compressive hoop stress at the borehole wall, $\sigma_{\theta \mathrm{w}}$, is reduced to a tensile stress equal to the tensile strength of the rock, σ_{ten}. This occurs when the wellbore pressure, p_{w}, increases to the following fracture initiation pressure:

$$p_{\mathrm{init}} = p_{\mathrm{p}} + 2\sigma_{\mathrm{h}} + \sigma_{\mathrm{ten}} \tag{4}$$

Once the hydraulic fracture propagates beyond the stress concentrations near the borehole wall, the predicted fracture propagation pressure reduces to:

$$p_{\mathrm{frac}} = p_{\mathrm{p}} + \sigma_{\mathrm{h}} + \sigma_{\mathrm{ten}} \tag{5}$$

When natural fractures or flaws are present, tensile strength can be neglected because near borehole stress concentrations have already been penetrated. Thus:

$$p_{\mathrm{frac}} = p_{\mathrm{init}} = p_{\mathrm{p}} + \sigma_{\mathrm{h}} \tag{6}$$

Eq. 6 is valid in many areas because of the following observations:

(1) During leak-off tests once the fracture has been initiated, significant decreases in pumping pressure are seldom observed.

(2) Repeated leak-off tests seldom show a decrease in the observed leak-off pressure.

When the vertical effective stress, σ_z, and horizontal effective stress, σ_{h}, are essentially equal, a horizontal fracture may occur. An irregularity in the borehole wall must be either naturally present or started by vertical fracture initiation. The irregularity must be present before a vertical component of force can be applied by the mud pressure to open a horizontal fracture. Weak interfaces at sediment bedding planes can help promote a horizontal fracture. For a uniform horizontal stress field, vertical stress concentrations would not be present near the borehole, and thus no differential is predicted between fracture initiation pressure and fracture propagation pressure. Eq. 6 would apply with $\sigma_{\mathrm{h}} = \sigma_z$.

2.3. Ratio of horizontal to vertical stress

Before fracture pressure can be predicted from Eqs. 4–6, the effective horizontal stress must be estimated. For sediments between the surface casing depth and the total well depth, the most common approach has been to correlate the minimum observed ratio, F_σ, of horizontal to vertical effective stress with depth. Leak-off test data and incidents of lost-returns have been used to develop empirical correlations for various geographic areas. The correlations were heavily weighted to represent the weaker sediments found at a given depth so that a conservative estimate of fracture pressure could be predicted for use in well design calculations. Once F_σ is obtained from the empirical correlation, the fracture pressure can be estimated using:

$$p_{\mathrm{frac}} = F_\sigma \sigma_z + p_{\mathrm{p}} = F_\sigma (s - p_{\mathrm{p}}) + p_{\mathrm{p}} \tag{7a}$$

Shown in Fig. 3 are several correlations commonly used to estimate the horizontal to vertical effective stress ratio, F_σ, for the Louisiana Gulf Coast Area. Note that the ratio decreases for the more shallow sediments and approaches a value of about 0.33 at the surface. Hubbert and Willis (1957) determined this value for unconsolidated sands in sand-box experiments conducted in the lab. At deeper depths, the ratio F_σ approaches a value of one as the sediments become more plastic with increasing confining stress.

Extrapolation of the empirical correlations shown in Fig. 3 to very shallow depths gives a low value of F_σ, and thus very low values of shallow fracture pressure are often predicted. Using the correlations

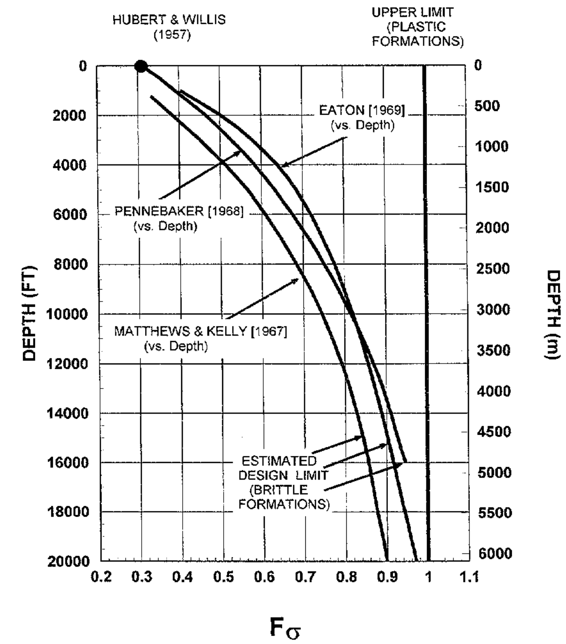

Fig. 3. Ratio of horizontal effective stress to vertical effective stress for the Louisiana Gulf Coast.

shown in Fig. 3 for clay sediments can result in unrealistic formation break-down pressures being used in the casing design calculations.

In reality, many upper marine sediments have F_σ values near one. The value of one for F_σ is also suggested by the following empirical relationship often used by geotechnical engineers (Lambe and Whitman, 1969):

$$F_\sigma = 1 - \sin\phi_f \tag{8}$$

Since the internal friction angle for clays, ϕ_f, is often very low, the value of sin ϕ_f is also small, indicating that F_σ is approximately one for undrained clays.

Shown in Fig. 4 are F_σ values estimated from leak-off tests from five wells drilled in the Green Canyon Area, Offshore, Louisiana. Note that the average observed value of the horizontal to vertical effective stress ratio ranges from 0.8 to 1.4 and averages about 1. The observed values in excess of 1 are likely due to: (1) experimental errors which occur while running and interpreting the leak-off

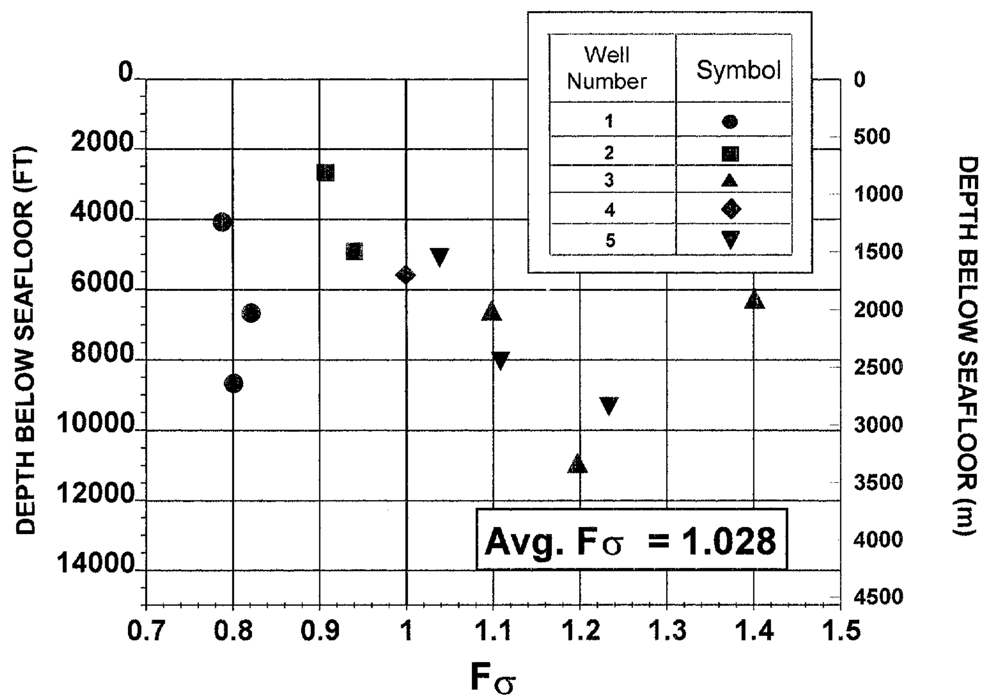

Fig. 4. Ratio of horizontal to vertical effective stress determined from leak-off tests in the Green Canyon area, offshore Louisiana.

tests, (2) the presence of stress concentrations in and around the borehole, and (3) the presence of non-zero tensile strengths in the sediments exposed during the test.

2.4. Overburden pressure

The total overburden pressure is the most important parameter affecting fracture pressure. The overburden pressure, s, at a certain depth can be thought of as the pressure resulting from the total weight of the rock and pore fluids above that depth (Edwards et al., 1982). Because bulk density, ρ_b, is a measure of the weight of rock and pore fluids, the overburden pressure at a certain depth can be easily calculated by integration of the bulk density versus depth profile.

$$S = \int_0^{D_s} \rho_b g \, \mathrm{d} D_s \tag{9}$$

Thus one method of calculating the overburden pressure is to sum up the average interval bulk density times interval height for all intervals above the depth of interest.

For offshore sediments, hydrostatic pressure due to water depth must also be considered and Eq. 9 becomes:

$$s = \int_0^{D_w} \rho_{sw} g \, \mathrm{d} D_w + \int_{D_w}^{D_s} \rho_b g \, \mathrm{d} D_s \tag{10}$$

The best source of bulk density data is from in situ measurements made with a gamma–gamma formation density log. Unfortunately such data is seldom available for depths less than the surface casing setting depth. Accuracy of the formation density logs can be poor in large diameter holes, so that a pilot hole may be required to get good measurements in the shallow sediments. Logging-while-drilling (LWD) tools are now available that can measure formation density, but they also require hole diameters no greater than 14 inches. Thus, a pilot hole may be required to get accurate density measurements in the upper marine sediments.

Sonic travel times determined from well logs or calculated using seismic data can also be used to estimate the formation bulk density. However, Rocha (1993) found that there was a poor agreement between density values obtained with sonic and density logs in the upper marine sediments. The difficulty stems from uncertain matrix travel time values for shallow clay sediments.

Density data can sometimes be obtained from cuttings while drilling in shallow sediments. The bulk density of cuttings can be highly altered by the release of confining pressure and by exposure to the drilling fluid.

2.5. Overburden stress as a function of porosity

Because of the problems discussed above, detailed information on bulk density is often not available at shallow depths. Thus, density at shallow depths must often be extrapolated from information obtained at deeper depths. Such extrapolations are typically done using porosity instead of bulk density.

Bulk density can be defined in terms of porosity, ϕ, and other variables using the following equation:

$$\rho_b = (1 - \phi) \rho_{\text{matrix}} + \phi \rho_{\text{fluid}} \tag{11}$$

From the above equation bulk density is primarily dependent on porosity since the other variables of grain matrix density and pore-fluid density usually do not have a wide range of values.

Porosity often decreases exponentially with depth, and thus a plot of porosity versus depth on semilog paper often yields a good straight-line trend. This exponential relationship can be described using the following equation.

$$\phi = \phi_0 \exp(-KD) \tag{12}$$

The constants ϕ_0, the surface porosity, and K, the porosity decline constant, are determined graphically or by the least-square fit method. Substituting Eq. 12 into Eq. 11 gives:

$$\rho_b = +[1 - \phi_0 \exp(-kD_s)] \rho_{\text{matrix}} + \phi_0 \exp(-kD_s) \rho_{\text{fluid}}$$

which after substituting into Eq. 10 and integrating, gives:

$$s = \rho_{sw} g D_w + \rho_{\text{matrix}} g D_s - \frac{(\rho_{\text{matrix}} - \rho_{\text{fluid}}) g \phi_0}{K} [1 - \exp(-kD_s)] \tag{13}$$

Rocha (1993) proposed that most shallow marine sediments found in the Gulf Coast (USA) have F_σ values approaching 1 in Eq. 7a. As the matrix stress coefficient, F_σ, becomes 1.0, the effect of pore

Table 1
Values for such porosity and porosity decline constant (after Rocha, 1993)

Area	ρ_{grain}	ϕ_0	K
Green Canyon	2.65	0.770	323 E−6
Main Pass	2.67	0.590	100 E−6
Ewing Bank	2.65	0.685	115 E−6
Mississippi Canyon	2.65	0.660	166 E−6
Rio de Janeiro area	2.70	0.670	18 E−6

pressure vanishes and fracture pressure becomes equal to the overburden pressure:

$$p_{frac} = 1.0(s_{pob} - p_p) + p_p \tag{7b}$$

Leak-off tests are then used to calculate a pseudo-overburden pressure, s_{pob}, using Eq. 7b. The constants of surface porosity, ϕ_0, and the porosity decline constant, K, are determined in order to get the best fit of the leak-off test data from Eq. 13 for $s = s_{pob}$. Rocha determined values for ϕ_0 and K for several areas in the Gulf Coast and Brazil. These values are given in Table 1.

3. Soil borings tests

A number of tests are routinely conducted on samples from soil borings by geotechnical engineers to determine the load bearing capacity of the shallow sediments. The properties tested generally fall into one of three categories:

1. Physical: Weight/density measurements;
2. Index: Atterberg limits; and
3. Engineering: Shear strength measurements.

Weight/density measurements include moisture content, wet unit weights, and dry unit weights. Atterberg limits tests measure the plastic and liquid limits of the soil. Shear strength measurements are made using miniature vane, Torvane, remote vane, cone penetrometer (CPT) and triaxial shear tests.

Tests can also be made of chemical properties such as acid solubility, gas and hydrocarbon content, water salinity, and X-ray analysis. Generally, chemical and X-ray tests are performed in the laboratory.

After being retrieved on the surface, but before being extruded from the sample tube, miniature vane tests for shear strength are performed. The sample is then extruded from the sample tube and cut. Representative portions are carefully packaged, sealed, and sent to the labs for additional testing. The remainder of the sample is tested in the field. Normal field tests are the Atterberg limits tests, visual classifications and various strength tests. Lab testing includes unconsolidated–undrained tests.

In situ values of shear strength, hydraulic fracture pressure, temperature, etc., can be obtained by using specialized tools at the bottom of a drill string.

3.1. Atterberg limits tests

The Swedish scientist, Atterberg (1905) proposed that a soil can exist in one of four possible states — solid, semisolid, plastic and liquid — depending on the moisture content of the soil. The moisture content is defined as the weight of water per unit weight of matrix material. The higher the moisture content, the more fluid the soil becomes. The moisture content at the point of transition from the semisolid state to the plastic state is known as the plastic limit. The moisture content at the point of transition from the plastic state to the liquid state is known as the liquid limit. The plastic limit and liquid limit are known as the Atterberg limits and are quantitatively determined by a standardized ASTM methods (Cassagrande, 1948).

3.1.1. Liquid limit

To determine the liquid limit, the soil is placed in a brass cup, and a groove is cut at the center of the soil pat with a standard grooving tool. Next, the cup is lifted and dropped repeatedly (using a crank-operated cam) from a height of 0.3937 inch (10 mm) onto a hard rubber base until the soil flow fills 0.5 inches of the bottom of the groove. The test is repeated at least four times for the same soil at varying moisture contents that require from 15 to 35 blows to close the groove.

The moisture content, in percent, and the corresponding number of blows are plotted on semilogarithmic graph paper to produce the flow curve. The flow curve is approximately a straight line. The moisture content corresponding to 25 blows using the flow curve is defined as the liquid limit. For moisture contents above this value, the soil is considered to have negligible cohesive strength and behave essentially as a liquid.

3.1.2. Plastic limit

The plastic limit test is a simple test in which the soil mass is rolled by hand on a ground glass plate from an ellipse into a thread.

The plastic limit is defined as the moisture content, in percent, at which the soil crumbles when rolled into 1/8 inch (3.2 mm) diameter thread. For moisture contents below this value, the soil would behave more like a semisolid, but would still have a non-linear (concave downward) stress–strain relationship.

3.1.3. Plasticity index and liquidity index

The plasticity index (PI) is the difference between the liquid limit and the plastic limit of the soil as stated in the following equation:

$$PI = LL - PL \tag{14}$$

The liquidity index is the ratio of the difference between the in situ moisture content and the plastic limit to the difference between the liquid limit and plastic limit.

$$LI = \frac{(w - PL)}{(LL - PL)} = \frac{(w - PL)}{PI} \tag{15}$$

If the liquidity index is greater than 1, the sediments can be transformed into a viscous form to flow like a liquid. A liquidity index greater than one implies the presence of sensitive clays and behavior somewhat similar to a drilling mud with a high gel strength. A liquidity index less than one implies some degree of consolidation and a liquidity index less than zero implies over-consolidation. A liquidity index of zero signifies the boundary between the plastic and semi-solid states.

3.2. Shear strength tests

3.2.1. Vane tests

Undrained shear strength, c_u, of very plastic cohesive soils may be obtained directly from vane tests. The shear vane usually consists of four thin, equal-sized steel plates welded to a steel torque rod. The vane is pushed into the soil and then torque is applied to rotate the vane at a uniform speed. The required torque is read from a torsion indicator. In conducting a field vane test, the vane is rotated at approximately 6 degrees per minute. The undrained cohesion, c_u, determined from vane shear test is a function of clay type and the angular rotation of the vane.

3.2.2. Torvane

The Torvane is a hand-held device with a calibrated spring used to determine the undrained cohesion, c_u, for the tube specimens. The Torvane can be used in the field and in the lab. The Torvane is pushed into the soil and then rotated until the soil fails. The undrained shear strength is read from a calibrated dial.

3.2.3. Miniature Vane

The miniature vane is a smaller version of the field vane test device. Miniature vane tests are done on the retrieved sample before being extruded from the sample tube.

3.2.4. Cone penetrometer test (CPT)

Penetrometers consists of a rod with a cone shape tip that is pushed into the soil at a standard rate while recording the required force. The test can be run in situ at the bottom of a drill string with the data stored in a downhole memory unit. Data is downloaded from the unit after it is retrieved by wire line.

3.2.5. Triaxial shear test

In this test, the cylindrical test specimen is about 1.5 inches (38.1 mm) in diameter and 3 inches (76.2 mm) in length. The test specimen is wrapped in a rubber membrane and placed inside a chamber filled with water or glycerin. Pressure applied to the water or glycerin is transferred to the soil sample. The soil sample is then sheared with a vertical loading ram. Drainage in or out of the soil sample and pore pressure can also be measured.

3.2.6. Unconsolidated–undrained test

In unconsolidated–undrained tests, drainage from the soil specimen is not permitted either during the application of chamber pressure or during the shear failure of the specimen. Since drainage is not allowed at any stage, the test can be performed very quickly.

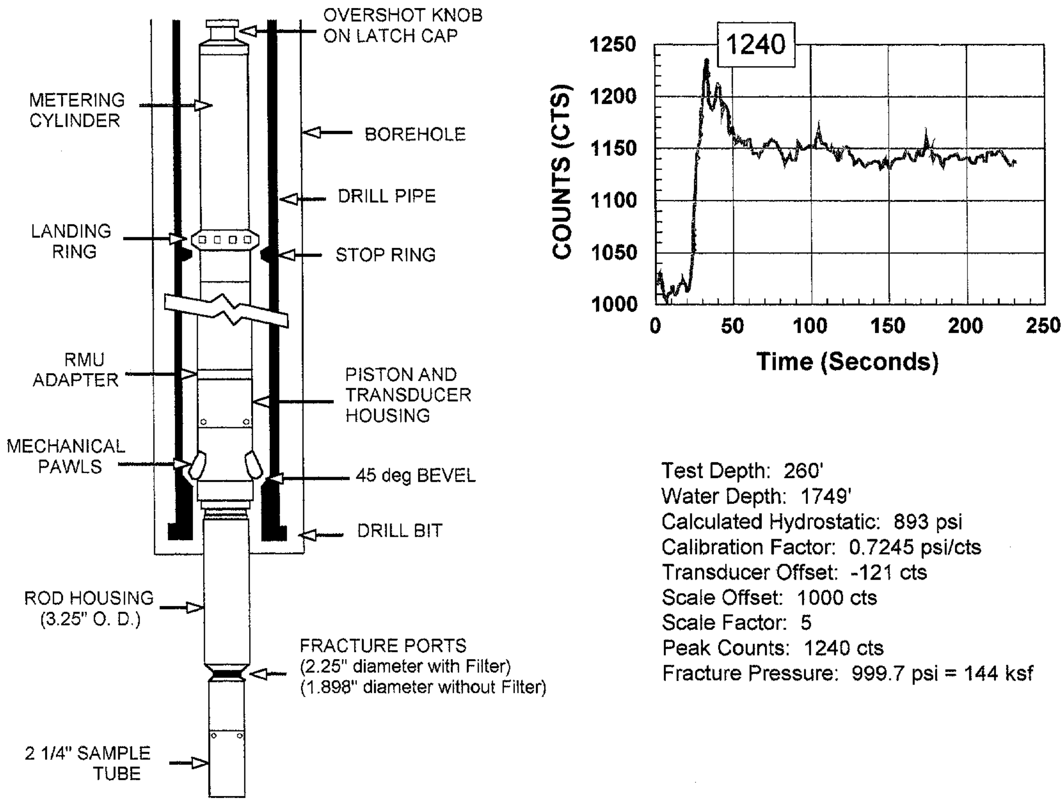

Fig. 5. Schematic of wireline retrievable hydraulic fracture tool. (Courtesy of Fugro–McClelland Marine Geosciences, Inc.).

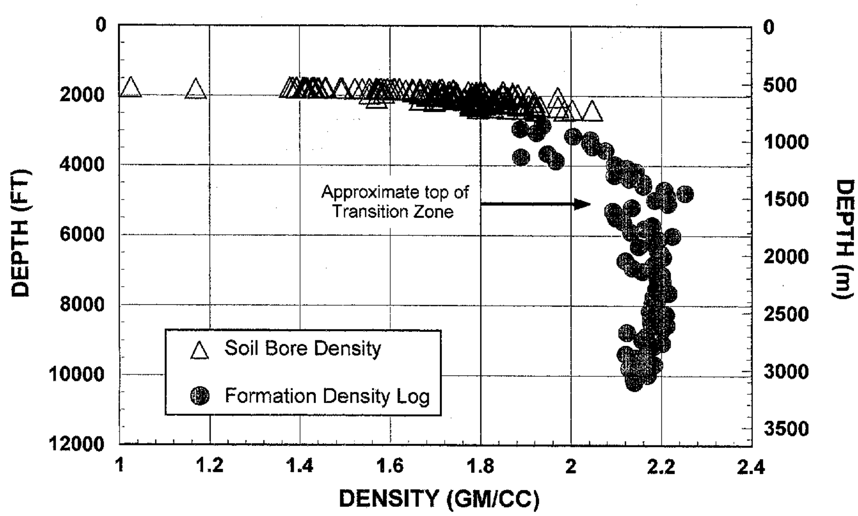

Fig. 6. Sediment bulk density versus depth for the Green Canyon area.

The test is usually conducted on clay specimens because in saturated cohesive soils, shear stress at failure is practically constant regardless of the chamber confining pressure.

3.3. Hydraulic fracture pressure

The hydraulic fracture test can be performed in situ using a wireline retrievable unit (Fig. 5) similar to the cone penetrometer test unit. Soil samples are removed from the test hole with a 2.25-inch (5.7 cm) O.D. thin walled tube. The wall thickness of the tube is about one-sixteenth of an inch (0.16 cm) to minimize disturbance and lateral compression of the sediments. An extension rod pushes the sampler cylinder into the bottom of the hole and at the same time packs-off a portion of the annulus above the sampler and outside the extension rod. Fluid is injected into the packed-off annular cavity at a constant rate of about 0.5 gal/min (0.0315 m^3/s) while recording the injection pressure. A record of the injection pressure versus time is stored in the unit and then down-loaded after the unit is brought to the surface. The unit is pulled from the sediments using the drill-pipe and once free can be retrieved by wireline.

4. Example results

The most important parameter needed to estimate sediment failure during shallow gas well control operations is the formation bulk density versus depth profile. Shown in Fig. 6 is a composite density versus depth profile for a prospect in the Green Canyon area in the Gulf of Mexico. The upper portion of the profile (triangles) is obtained from wet unit weight data collected from soil borings. The lower portion of the profile (circles) is obtained from a formation density log in a nearby well.

In Fig. 6, there is a decrease in density starting at about 5000 ft (1524 m) that indicates the beginning of an overpressured formation and hence the approximate top of the transition zone (Fertl and Chilingarian, 1989). The integration of the density profile produces the overburden pressure versus depth curve shown in Fig. 7.

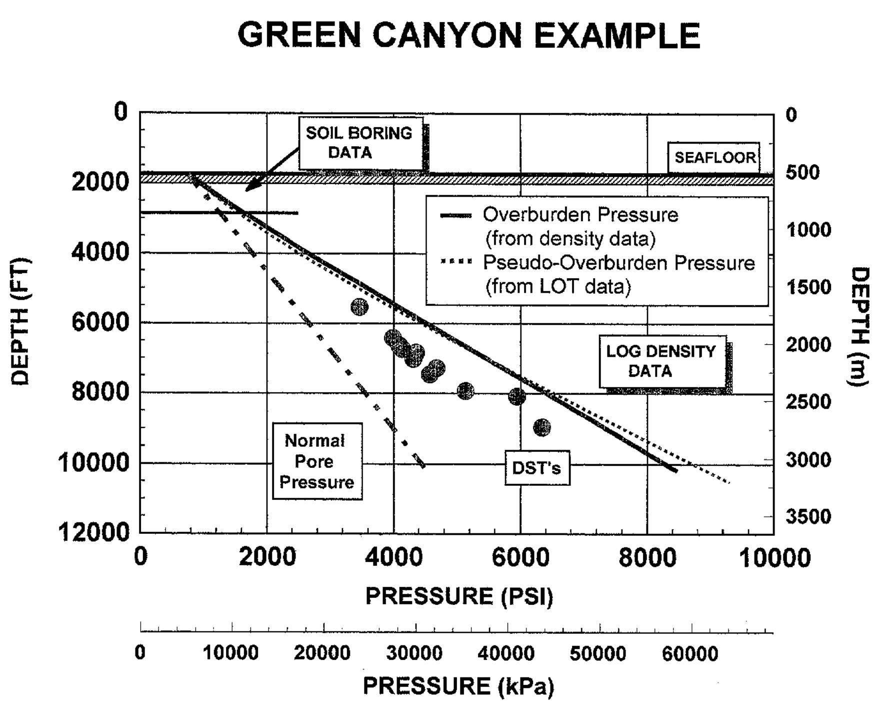

Fig. 7. Overburden pressure and pore pressure versus depth for the Green Canyon area.

Fig. 7 has several pressure versus depth curves. The solid line is the total overburden pressure versus depth profile from integrated density data. The upper part (the first 650 ft or 198 m) of this overburden curve uses bulk density from soil boring data. The lower portion of this overburden curve uses bulk density from logs. The dark dashed line is the pseudo-overburden pressure versus depth curve determined from leak off test data (Rocha, 1993). The pseudo-overburden pressure and the overburden pressure versus depth curves closely match each other.

In Fig. 7 to the left of the overburden pressure curves is a light-shaded dashed line indicating normal pore pressure using the 0.465 psi/ft gradient as suggested by Edwards et al. (1982). The actual pore pressures are determined from drill stem tests in nearby wells and are depicted as shaded circles in Fig. 7. These drill stem tests confirm the presence of abnormal pressures below 5000 ft (1524 m) as suggested by the density versus depth graph (Fig. 6). The difference between the actual pore pressures (the drill stem tests) and the hydrostatic formation pressure is known as the abnormal component (Khilyuk et al., 1994).

Fig. 8 summarizes the results of the tests conducted on the samples taken from the soil borings. The first column in Fig. 8 is a lithology description.

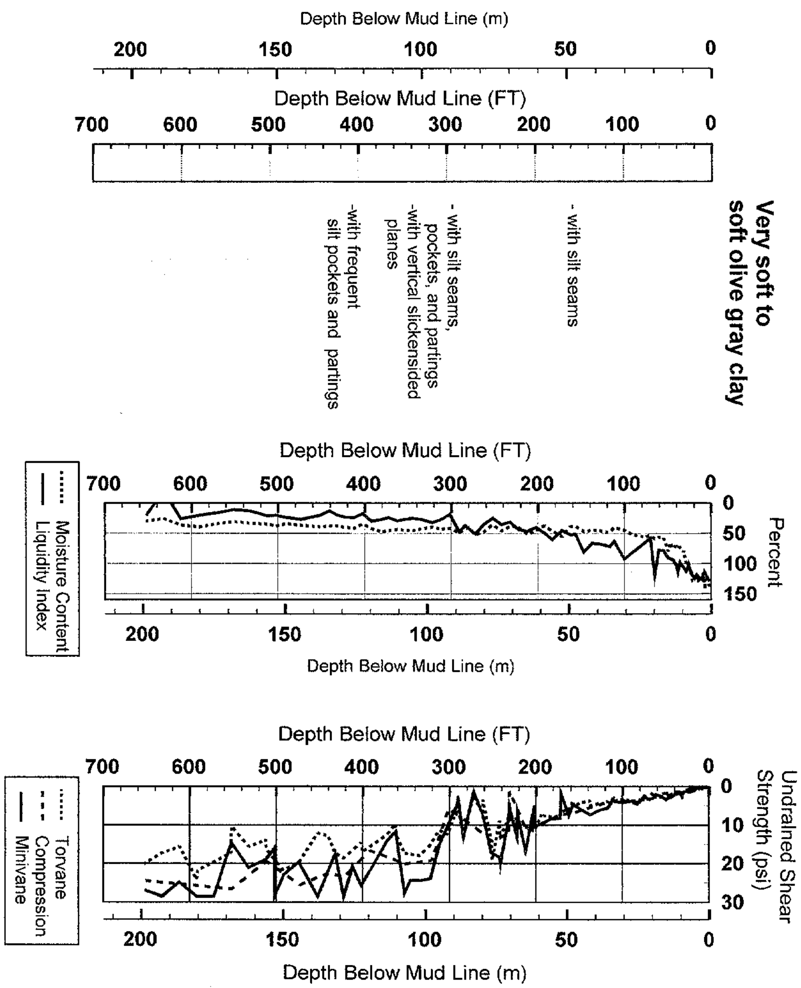

Fig. 8. Lithology, liquidity index, moisture content and shear strenght versus depth for the Green Canyon area.

From the lithology description, the sediments penetrated by the soil borings are impermeable (only clay is found). These clays are classified as very soft to soft olive gray clay. The second column plots moisture content and liquidity index values versus depth below the seafloor. The liquidity index is greater than one for the top thirty (30) feet indicating the liquid phase. The liquidity index remains above zero for the rest of the column except for a small interval near the bottom. Since the liquidity index is between zero and one for most of the column this indicates the plastic state.

The third column in Fig. 8 plots shear strength values versus depth below the seafloor. Measured shear strengths of the sediments reach a value of about 25 psi near the bottom of the interval penetrated. Thus, a significant tensile strength would not be expected. Skempton's formula is sometimes used as an empirical relation between shear strength and effective vertical stress for normally consolidated sediments. Skempton (1957) proposed the formula:

$$\frac{C_u}{\sigma_z} = 0.11 + 0.0037(LL - PL) \tag{16}$$

which shows that the ratio of shear strength to effective vertical stress is about 11%, with a correction for liquid limit and plastic limit. At the bottom of the penetrated interval, the effective vertical stress is 210 psi (1448 kPa), the liquid limit is 61% and the plastic limit is 22%. Using these values in Skempton's formula gives a value of 11.14% and predicts a shear strength of about 53 psi. Thus Skempton's formula predicts a higher shear strength value than observed in the Green Canyon area example located in the Gulf of Mexico.

Shown in Fig. 9 is a plot of the horizontal to vertical effective stress ratio, F_σ, as determined using the in situ hydraulic fracture tool run when the soil borings were being taken. Note that all of these results show values near one or in excess of one. Because the tool is testing such a small sample of sediment (only a few inches), the test is much less likely to encounter major flaws in the exposed sediment. The effect of stress concentrations in the borehole wall would allow F_σ to be as high as 2.0. The lower limit of F_σ (about 1.0) would be a more

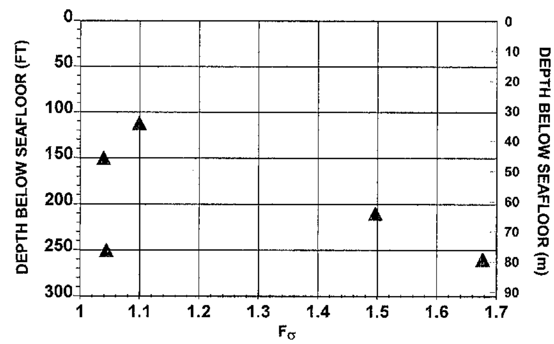

Fig. 9. Ratio of horizontal to vertical effective stress measured using the in situ hydraulic fracture.

representative value to use when a large interval of borehole is exposed.

Because F_σ appears to be near 1.0, a reasonable estimate of formation break-down pressure for clay sediments for this example is the calculated overburden pressure shown in Fig. 7. The leak-off test results (Fig. 4) tend to confirm that F_σ remains near 1.0 even for the deeper sediments. If well-developed sands are known to be present, a lower value for F_σ should be used for those zones. In the absence of leak-off tests for the sand intervals of interest, the use of a minimum observed value for F_σ from the available leak-off test data should be considered. Note that the minimum value seen in Fig. 4 was about 0.8.

5. Conclusions and recommendations

Geotechnical studies using soil borings provide a useful and sometimes overlooked supplement to the available data needed to design a well for shallow-gas well control. In the past there was sometimes only marginal interaction between the geotechnical engineer designing the foundation of an offshore structure and the petroleum engineer designing the casing program of the wells to be drilled from the structure. The assumptions that the shallow sediments are too weak to consider shutting-in the well prior to setting surface casing and that the diverter operations would always solve the problem, regardless of conductor depth selected, are not always correct. Design loads and failure mechanisms for shallow well control operations need to be viewed in a systematic way.

In as much as the entire structure can be put at risk by sediment failure occurring during well control operations, a strong case can be made for a more interdisciplinary approach to the design of the structural and conductor casing strings. Interpretation of the soil borings data by the geotechnical engineer can provide useful casing design data. Loads imposed during well control operations should be considered in addition to loads imposed by the weight of subsequent casing strings. Rather than stopping a soil boring at a depth where sufficient sediment strength has been penetrated to design a foundation for the structure, borings could continue until sufficient data has been collected to allow the structural and conductor casing strings to be designed with confidence for well control operations.

The described method of determining fracture pressure from soil borings tests gives excellent results for the areas studied in the Green Canyon Area, Gulf of Mexico.

5. Nomenclature

ϕ	porosity
ϕ_0	surface porosity
ϕ_f	angle of internal friction
ρ_b	bulk density
ρ_{fluid}	pore fluid density
ρ_{matrix}	matrix or grain density
ρ_{sw}	density of the seawater
σ_f	failure stress
σ_1	maximum effective (matrix) stress
σ_3	minimum effective (matrix) stress
σ_h	horizontal stress
σ_{max}	maximum effective (matrix) stress
σ_{min}	minimum effective (matrix) stress
σ	stress
σ_{rw}	principal wellbore stress in the r direction
$\sigma_{\theta w}$	principal wellbore stress in the θ direction
σ_{zw}	principal wellbore stress in the z direction
σ_{ten}	tensile stress
σ_z	vertical effective (matrix) stress
τ_f	failure strain
c	cohesion
c_u	undrained shear strength
D	depth
D_w	water depth
D_s	depth of the sediment below the seafloor
F_σ	horizontal to vertical matrix stress coefficient
g	gravitational constant
K	the porosity decline constant
LI	liquidity index
LL	liquid limit
PI	plasticity index
PL	plastic limit
p_p	pore pressure
p_{frac}	fracture pressure
p_{init}	initial fracture pressure
p_w	wellbore pressure
s	overburden pressure
s_{pob}	pseudo-overburden pressure
w	in situ moisture content

Acknowledgements

The authors wish to acknowledge Tom Hamilton, Senior Vice President, and Jane Vovk, Librarian, of Fugro–McClelland Marine Geosciences, Inc. for their invaluable assistance in this study.

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DRILL STRING SAFETY VALVE TEST PROGRAM

by

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OBJECTIVE

The objective of this task was to experimentally measure the torque required to close and open drill string safety valves for various flow rates, back pressures, and valve designs.

ABSTRACT

As a primary component of the drillpipe blowout protection system, drill string safety valves should be very reliable. The drill string safety valve's reliability is questionable in its current design configuration. The Petroleum Engineering Research and Technology Transfer Laboratory (PERTTL) under grants from the U.S. Department of the Interior's Minerals Management Service has conducted research to investigate the mechanism of failure associated with the common failure modes. The research also intends to make recommendations for designs that will solve the reliability problems associated with these valves.

INTRODUCTION

A study of blowout preventer pressure test results by the Minerals Management Service (MMS) for the U.S. Outer Continental Shelf during 1993 and 1994 identified drill string safety valves (DSSV's) as one of the least reliable components of the well control system **[Hauser, 1995]**. **Figure 1** details the results. Note that the pressure test failure rate for drill string safety valves and inside blowout preventers was about 25%. This was especially troublesome, since the level of redundant protection for blowouts through the inside of the drill string is much less than for flow through the annulus. Note also the choke manifold had a high pressure test failure rate. A failure in this component is not as serious because these valves are not a primary blowout barrier. Failure of one of these valves generally would not lead to a blowout. Because it is a primary blowout barrier for the drill string, failure of the drill string safety valve could have devastating results.

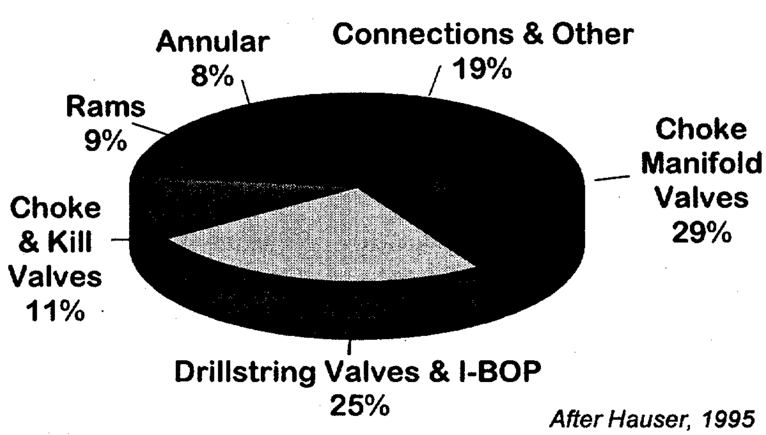


Figure 1: Results compiled from blowout preventer component pressure tests for the U. S. Outer Continental Shelf during 1993 and 1994.

In 1994, Mobil conducted an industry survey which identified 29 safety valve failures during well control operations over an unspecified period. The survey was conducted after Mobil experienced a number of problems in 1993 with stabbing valves leaking after being stripped into a well in a threatened blowout situation. The survey findings, as listed below **[Tarr, 1996]**, identify several common failure modes for safety valves that point to problems inherent to the basic design of the DSSV's.

- Failure to seal against pressure from below
- Failure to open when under pressure due to high torque
- Failure to seal against pressure from above
- Failure to seal against outside pressure when stripped into a well
- Failure to close due to high torque when throttling mud backflow
- Failure to seal due to erosion from abrasive flow

Brian Tarr, one of the authors of the study and a Mobil employee, is also chairing an API Task Group Subcommittee to recommend changes to API Specification 7, Section 2 for Safety Valves. The subcommittee is recommending a new classification scheme for safety valves based on performance testing of valve prototypes. A project jointly sponsored by Mobil and the Gas Research Institute was funding tests of two new prototype valves at the University of Clausthal in Germany. The new prototypes being tested were from German and Canadian manufacturers. The test protocol being followed were the draft procedures being considered by the API Task Group Subcommittee.

In 1995, MMS sponsored a project at LSU to study the failures of DSSV's and recommend improved designs for these valves to help prevent blowouts through drillpipe.

The following topics will be discussed in this report: (1) a review of the basic drill string safety valve terminology and function, (2) common failure modes of DSSV's, (3) identification of alternative devices that can be used with a safety valve to improve reliability, (4) the problems associated with the design of DSSV's that are being addressed by the MMS/LSU project, (5) the experimental test apparatus and procedures, (6) DSSV test results from industry and the results from the experiments at PERTTL, and (7) the recommendations and conclusions drawn from this test data.

DRILL STRING SAFETY VALVES (DSSV'S)

Drill string safety valves are ball valves used to stop flow through the drill string. Shown in **Figure 2** is a photograph of a traditional *TIW* drill string safety valve. The patent has expired on this simple design which is now available from several manufacturers in addition to *Texas Iron Works* (TIW) from which it took its name. The name *TIW Valve* is often used as the generic name for a drill string safety valve. This photograph was taken during a visit to a valve manufacturing facility. The valve has been disassembled here to show the main working components.

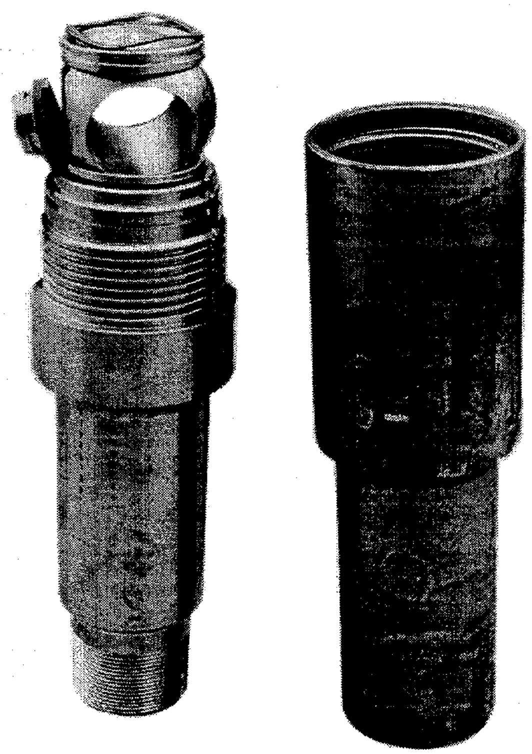


Figure 2: Photograph of the traditional *TIW* drill string safety valve.

Figure 3: Photograph of a safety valve which has been cutaway and made-up on top of a section of drillpipe.

When rotated 180 degrees, the portion of the safety valve shown on the right side of Figure 2 would accept the upper valve seat and spring and screw down over the ball. After assembly, the ball "floats" between the upper and lower seats and seals when pressure is applied against the ball. The spring assists in providing a low pressure seal. The valve stem fits into a circular hole in the valve body. The valve is operated by means of a wrench that is inserted into the valve stem and turned one quarter turn.

Displayed in **Figure 3** is a photograph of a safety valve made-up on top of a section of drillpipe. The valve has been cutaway so that the ball and seats may be observed. This particular safety valve is a one piece valve design that eliminates the need for threads in the valve body area. This not only decreases the number of possible leak paths, but also eliminates the problem of the ball locking due to excessive make-up torque. The basic design remains with a floating ball in a cage which houses the fixed upper and lower seats.

Shown in **Figure 4** are the traditional locations of safety valves. Government regulations require that a safety valve, with an operating wrench, for each size drillpipe be maintained on the rig floor at all times.

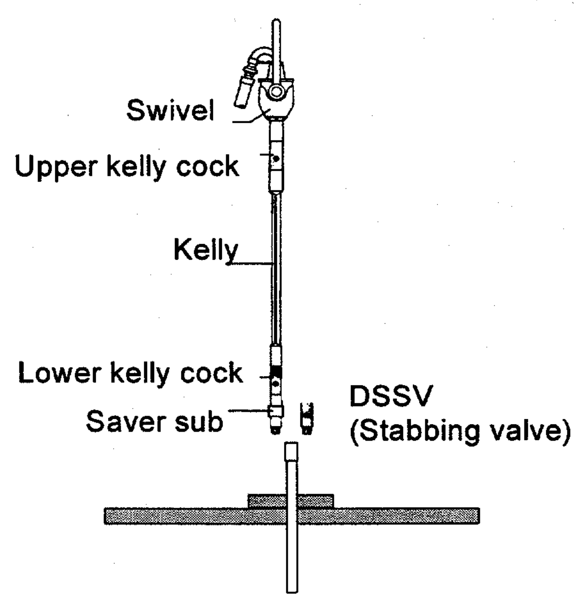


Figure 4: Schematic showing traditional locations of safety valves.

COMMON FAILURE MODES

During fishing operations in the J.W. Goldsby No. 1, observations began to indicate that the 18.0 ppg mud in the hole was insufficient to maintain well control. After backing off the pipe in preparation to sidetrack the well, it began to flow up the drillpipe. The well would not flow with the kelly attached, but flowed when the kelly was removed. It was decided that the kelly saver sub and the DSSV would be left on the drillpipe in the closed position in order to rig up chicksan to the trip tank. After the chicksan was rigged up, the DSSV was opened and it was noted that the well was flowing. The DSSV was closed but failed to seal. In the time it took to ready a second DSSV, the well flowed 25 bbls. Stabbing the valve on a joint of drillpipe to overcome the flow, the second valve would not seal when closed. A third valve was stabbed using the same technique and also would not seal when closed. Attempts to close the valve included rigging the valve wrench to the catline to try to force the valve closed. This resulted in bent and sheared wrenches. **Figure 5** is a photograph of the well taken during the blowout. The well was estimated to be flowing at 1000 BPH with a measured flowing pressure of 3800 psi and a shut in pressure of 7300 psi.

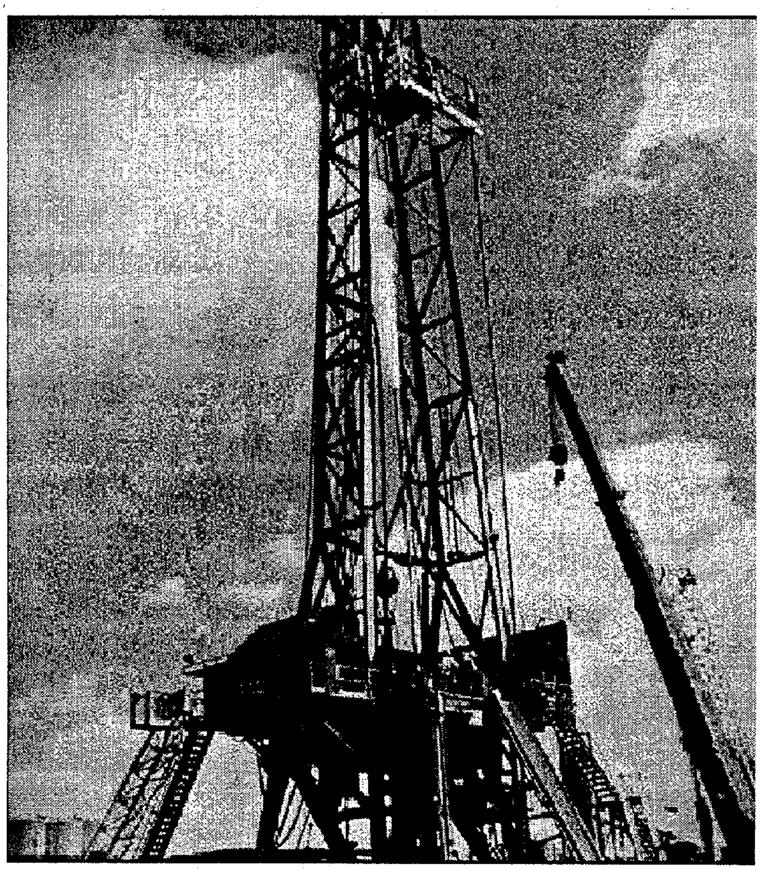


Figure 5: Photograph of Amoco Goldsby Blowout.

Amoco conducted a series of safety valve tests at their research lab after their Goldsby Blowout in 1990. The results of this unpublished study provides information on common failure modes for safety valves. The Goldsby blowout let the high pressure, high flow rate fluid move from below the valve, past the ball and seats, and out of the top. A similar failure occurs when pressure testing equipment is installed on top of a faulty safety valve which allows flow from above the valve, past the ball and seats, and into the drillpipe below. This prevents a valid pressure test from being performed.

Eroded balls, seats and seals are common. The erosion is due to flow of mud solids through the valve as it is being closed. These failures are caused by a partially closed or over rotated valve. If high flow rates are going to be stopped, the valve must be shut completely and quickly. If the valve is not completely closed in one quick motion, a narrow flow path is created between the ball and the seat, eroding the closing side of the seal in a very short time. If the valve is slammed shut there is a possibility of a permanent deformation in the valve stem stop. This deformation allows the ball to be over rotated causing a flow path to erode the seal on the opposite side. However, if the ball is not aligned perfectly in the open position, erosion in an upper or lower kelly valve will also occur during normal drilling operations. In addition, erosion is caused by wireline work done through the valve.

After stripping a stabbing valve into the well, a failed safety valve can let pressure move from the annular space around the valve, in through the valve stem, and into the drillpipe. Surface pressure readings will be irregular or misleading and could cause mistakes to be made during the well control operations. This is caused when the stem is eroded by an unintentional flow path or is damaged by stress cracks. Failed elastomers can also cause this type of failure.

Failure of the valve to close within the available torque limits is another significant failure mode. About 400 ft-lbs is generally regarded as an upper limit of torque that can be applied manually with an operating wrench. If the torque required to completely close the valve is exceeded before the valve is fully closed, the one of the failures associated with partially closed valves can occur. High torque is caused by the build up of pressure in the valve as the valve begins to restrict the flow. The pressure pushes the valve stem further into and against the valve body and the ball is forced against the upper seat. These two actions create friction forces that can not be overcome. If the ball and stem are put under too much pressure, local stress deformations create metal to metal contacts with the associated high friction surfaces. Poor dimensional tolerances also allow metal to metal contact. The ball of a two-piece valve often locks if too much make-up torque is applied across the valve body. Tong placement is critical when tightening across this type of valve.

Failure of the valve to open on a pressure differential or even after pressures are equalized across the ball is also a failure mode. When the torque required to open the valve to start well control operations is too high, the valve has completely failed. It is sometimes necessary to freeze a plug of ice-mud below the safety valve so that the valve can be replaced while there is pressure on the drillpipe. Higher torque values occur during opening yet are caused by the same actions associated with high torque values during closing.

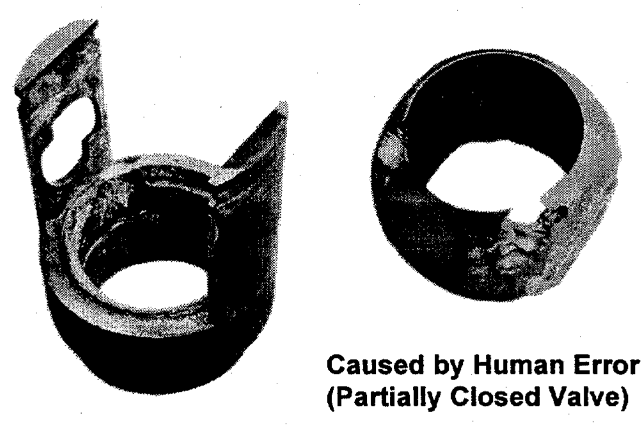


Figure 6: Photograph of ball and seat that has been eroded by mud flowing through a partially closed lower kelly valve.

Shown in **Figure 6** through **Figure 12** are photographs of failed safety valve components. These photographs were taken during a visit to a safety valve manufacturer and at PERTTL. They illustrate some of the types of failures that have been discussed. The backgrounds of the photographs have been cleaned up electronically to better show the components of interest.

Shown in **Figure 6** is a photograph of a ball and seat that has been eroded by mud flowing through a partially closed lower kelly valve. The valve was erroneously left in this position during drilling operations and would not seal during a well control event.

An example of a safety valve ball cut by wireline work being done through the valve is illustrated in **Figure 7**. In order to achieve as large a bore as possible, there is not much extra sealing area on the spherical surface near the ID of the ball. This type of wear can open a leak path that can then be further eroded by flow of mud.

A valve seat cut by fluid erosion due to a slightly over closed valve is depicted in **Figure 8**. Wear on the valve stem stop can sometimes allow too much rotation of the ball. The design of the valve stem stop is very important. A photograph illustrating a failure in the valve stem is shown in **Figure 9**.

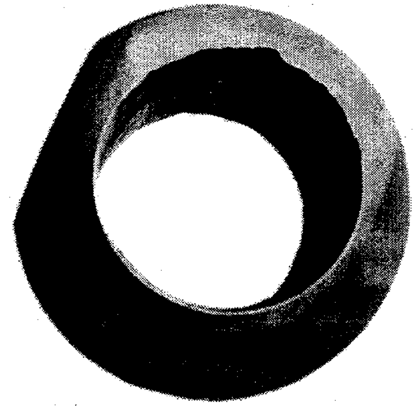


Figure 7: Safety valve ball cut by wireline.

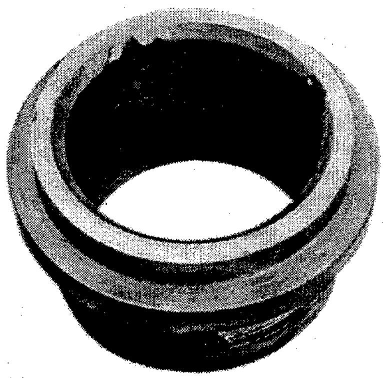


Figure 8: Valve seat cut by fluid erosion caused by over-rotation of the ball valve.

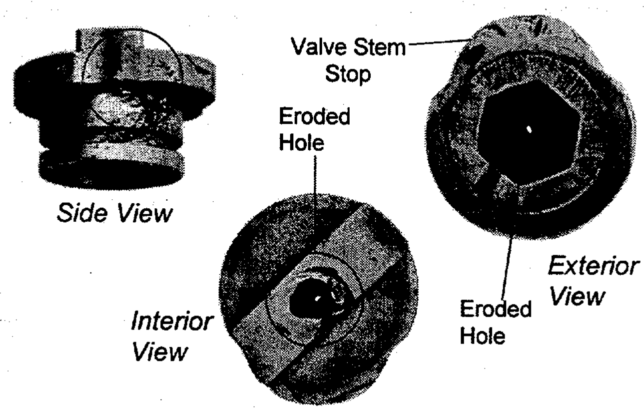


Figure 9: Photograph illustrating valve stem failure.

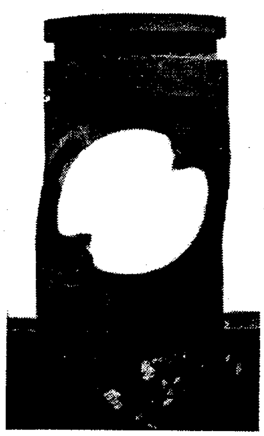


Figure 10: Ball cage deformed around stem opening by excessive torque.

Figure 11: Seal erosion caused by over rotation of the ball.

Figure 12: Valve stem wear due to ball cage deformation.

Figure 10 shows a valve component that has been subject to excessive torque, which caused permanent deformation in the ball cage and valve stem stops. The resulting deformation allowed over rotation of the ball which caused seal erosion (shown in **Figure 11**) and metal to metal contact between the ball cage and the valve stem. This contact is apparent from the wear shown in **Figure 12** on the valve stem.

AUXILIARY DEVICES

Patent searches have supplied good coverage of devices to prevent blowouts through the drillpipe. After 23 patents were reviewed, it was found that a number of alternatives to ball valves have been tried. However, ball valves appear to be best suited to the need for full opening valves with a small outside diameter that can be stripped into the well under pressure. Therefore, auxiliary equipment that compliments the use of safety valves and increases the number of barriers to a blowout through the drill string is preferred. Much of this auxiliary equipment has been identified through discussions with industry experts. The auxiliary equipment identified for added blowout barriers included shear rams, floats or check valve placed in the drill collars near the bottom of the drill string, a drop-in check valve, a velocity triggered check valve, and a double valve assembly.

Shear rams can be used to cut through the drillpipe and close the well on top of the drillpipe if the safety valve fails. The disadvantage of shearing the drillpipe and dropping it to bottom is that it can make it more difficult to eventually circulate kill mud to the bottom of the well.

Floats or drill collars are widely used by some operators to make it easier to stab and close safety valves at the surface. Both flapper and dart type check valves are available. Even if the check valve leaks, the flow rate is generally reduced enough so that the safety valve can be successfully closed without cutting out the valve. Operators may not want to use floats for the following reasons: (1) extra time is needed to fill the inside of the pipe when lowering pipe into the well, (2) higher surge pressures occur when pipe is lowered into the well, and (3) the shut-in drillpipe pressure is more difficult to read after taking a kick.

The drop-in check valve overcomes many of the objections to a float in the drill collars. **Figure 13** is a schematic of a drop-in check valve. A sub that will accept a check valve is run in the drill string near bottom. Just before it becomes necessary to pull the drill string from the well, the check valve assembly is dropped into an open drillpipe connection and pumped to bottom where it latches into the sub. If the well tries to blowout during tripping operations, the check valve will stop the flow and make it easy to stab and close the

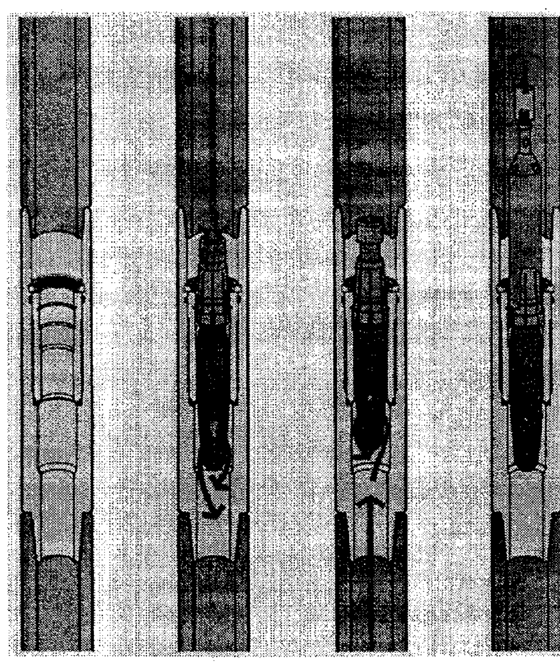


Figure 13: Schematic of a drop-in check valve.

surface safety valve as part of the shut-in procedure. In the event wireline work below the check valve becomes necessary, the drop-in check valve is wireline retrievable.

An example of a velocity triggered check valve is shown in **Figure 14**. This valve was designed and tested to a limited extent during the late 70's by Hughes Tool Company for Shell. It was lost in the shuffle of buy-outs during the 80's. Prototype valves are again being built by a new company. Future research will test this valve as part of the MMS project at LSU.

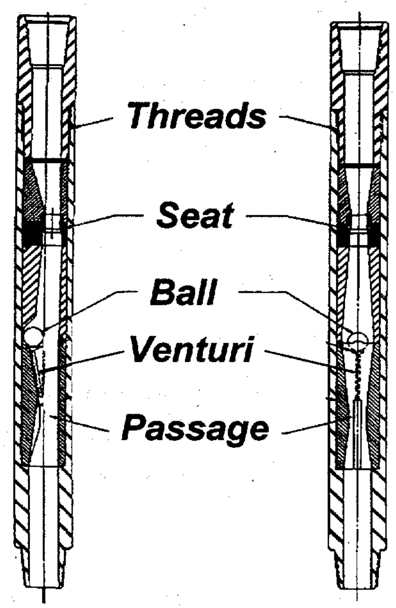


Figure 14: Velocity triggered check valve.

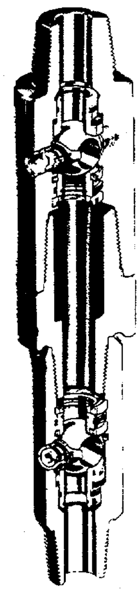


Figure 15: Double ball valve assembly.

In the double valve assembly, as seen in **Figure 15**, we assume that the lower ball may cut out for high flow rates but that the flow rate should be reduced enough to allow the upper valve to be successfully closed if it is closed before the bottom valve totally fails. The bottom valve can also be used as a mud saver valve since a back-up valve is available.

The problem with this approach is that it is not well suited to stabbing valves because of the extra weight that must be handled. A single stabbing valve for 4.5-in. or 5-in. drillpipe weighs more than 100 lbs. To minimize the weight of a double valve, one manufacturer is currently working on a double ball, single body design. This new valve design is currently being field tested by Amoco near Baton Rouge in the Tuscalousa trend.

TEST APPARATUS

The test apparatus designed for the data acquisition associated with testing the DSSV's is shown in **Figure 16** and **Figure 17**. The torque sensor is the primary data generating device used in the testing of the DSSV's. The sensor was chosen over a torque wrench because the information from the sensor is much easier to incorporate with other data taken during the experimental tests. The torque sensor is manufactured in such a way that it is simple to put the apparatus together quickly. A pneumatic actuator is used to open and close the DSSV's with the torque sensor fixed between the valve and the operator. The actuator is designed to be used

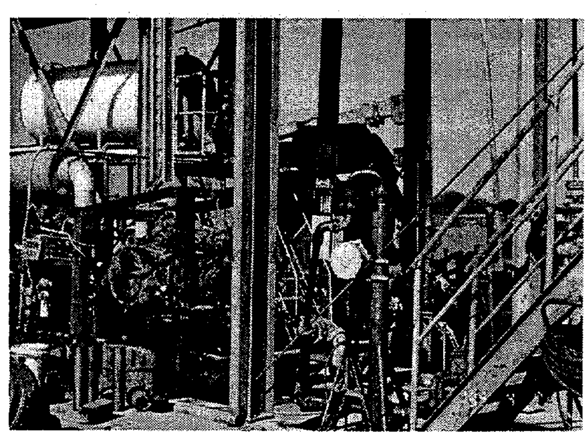


Figure 16: Test apparatus with pump in background.

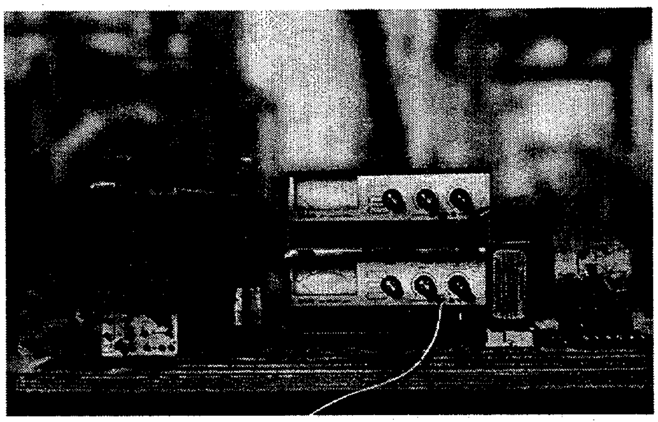


Figure 17: Test apparatus torque sensor, operator, and potentiometer

with valves that open and close through ninety degrees. The force generated by the actuator is supplied by air pressure coming in through a low pressure regulator. The actuator is easily activated using a shuttle valve located downstream from the pressure regulator. The position of the valves is determined from a signal generated by a resistance potentiometer fixed to the actuator. A check system is utilized to tell if the valve is closing completely. A microphone is fixed to the valve and the flow noise is amplified and displayed on an oscilloscope next to the valve. The operator can easily see when the valve has complete closure by looking at the noise generated by the microphone.

The data is acquired through an analog to digital PC board and stored using LabView software. Additional sensors to record pressure in the test string also generate signals recorded by the software during the tests.

TEST PROCEDURES

The testing of the DSSV's was done in two different ways: (1) a static pressure test, and (2) closing on flow. The static pressure test consists of putting the test piping and equipment in the configuration shown in **Figure 18**. When the test string is pressured to the test pressure set at the choke, the drill string safety valve is subjected to static pressure. The valve is then closed on this static pressure and the torque and other data is recorded. The next test point is taken by increasing the set point of the choke to a higher pressure setting.

The flow test configuration is shown in **Figure 19.** To test the valve under flowing conditions, circulation through the test piping is established at the test rate. The valve is closed on the flow and the torque and other data is recorded. To move to the next test point, the flow is increased to the next desirable level.

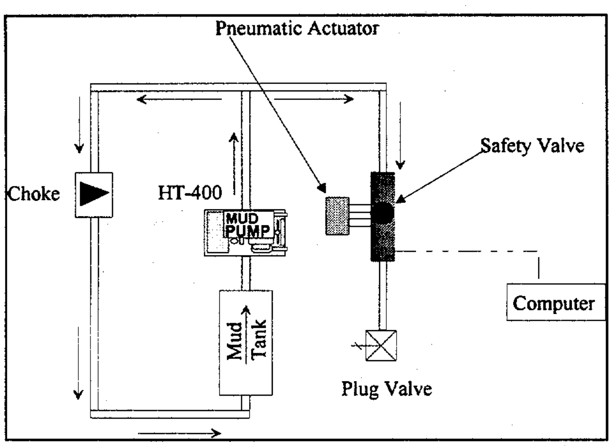


Figure 18: Static test diagram.

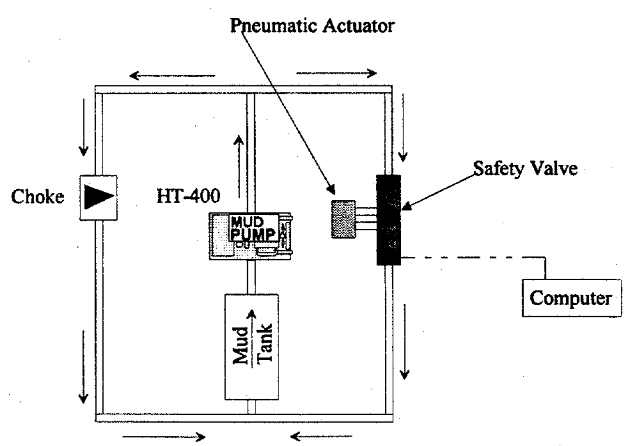


Figure 19: Flow test diagram.

FINDINGS

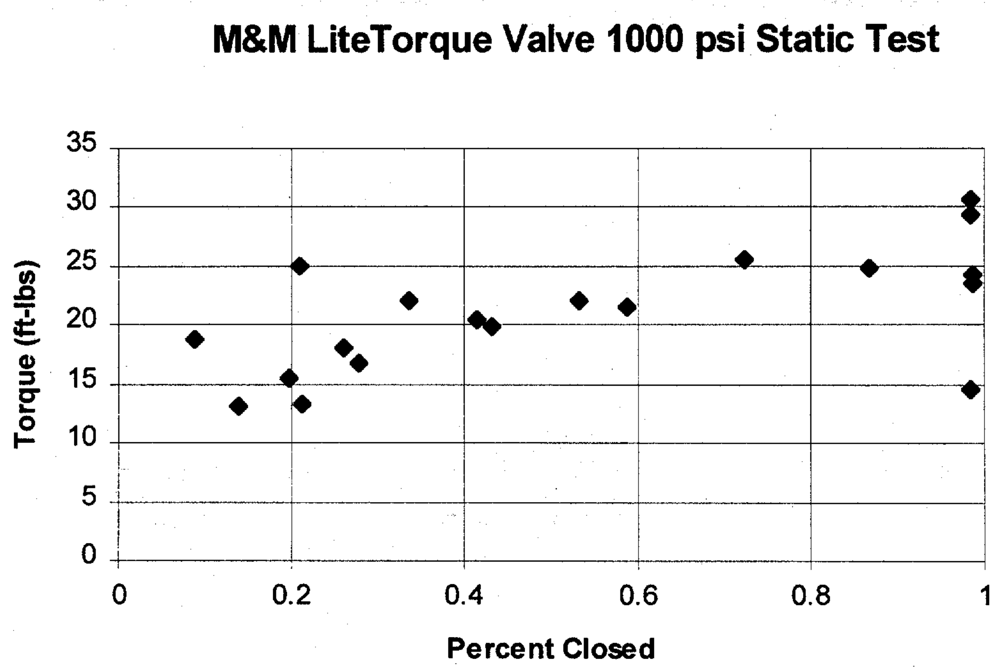
Using the test apparatus and the testing procedures, test results for two commercially available valves were obtained from two different experiments. The static pressure test was performed on a TIW two-piece valve and an M&M LiteTorque valve. The flow test was also performed on these two valves. The static pressure test was performed at 1,000 psi on each of the valves. The collected data for the two valves are shown side by side in **Figure 20** to make a comparison between the two valve designs. Closing values of twenty-five to thirty-five foot-pounds of torque for the Lite- Torque valve are three to four times smaller than the 110 to 115 foot-pounds of torque for the two-piece (TIW) valve. **Figure 21**, the graphs for the 2,000 psi static tests, shows the LiteTorque valve torque values ranging from twenty to forty foot-pounds and the two-piece (TIW) valve torque values exceeding 300 foot-pounds. At 3,000 psi, the LiteTorque valve has torque values that do not exceed fifty-five foot-pounds and the two-piece (TIW) valve exceed 500 foot-pounds. These graphs are shown in **Figure 22**. The static pressure tests of the different valves makes the design differences of the two valves more apparent. The LiteTorque valve contains a bearing between the stem and the valve body. This bearing reduces the frictional forces between the valve stem and the valve casing. The two-piece valve based on a more conventional TIW design does not have the bearing between the stem and the casing and the frictional forces in this area cause increased torque values to be obtained.

The flow test was performed using flow rates that started at 100 gallons per minute (gpm) and increased by 50 gpm up to 350 gpm. Three closing cycles were recorded at each of the flow rates for the M&M LiteTorque valve and the M&M two-piece (TIW) valve. The results for the LiteTorque valve and for the two-piece valve are shown in **Figure 23** and **Figure 24**. Although the flow test data for the two valves differs significantly in value, the condition of the two valves also varies significantly. The LiteTorque valve was flow tested after being used to calibrate the test apparatus in a variety of configurations. This particular valve had been used extensively as the "set up" valve for all of the testing procedures for many months. The two-piece TIW valve was rebuilt with completely new elastomer seals around the stem and new teflon seals in the seats. The past use the LiteTorque valve and the recent rebuild of the two-piece TIW valve make up for the difference in the torque values that were recorded in the data.

CONCLUSION AND RECOMMENDATIONS

The following conclusions can be drawn based on the results obtained in this study to date:

1. Some of the DSSV's tested in this study would not close above 180 gpm with 600 ft-lbs of torque. A significant chance of valve failure has been observed both in this study and in the field. Since valve failure and a lack of redundancy corresponds to a lack of protection for the drillpipe, auxiliary devices should be available in case of safety valve failure.
2. The results observed for each valve proved to be a function not only of its design and condition, but also the closing technique of the operator in the test stand.
3. Preparation of a training tape to instruct personnel on the common causes of valve failure and on the correct valve closing technique is recommended.
4. Additional testing of the current DSSV designs and the refinement of current designs or the development of additional designs is recommended.



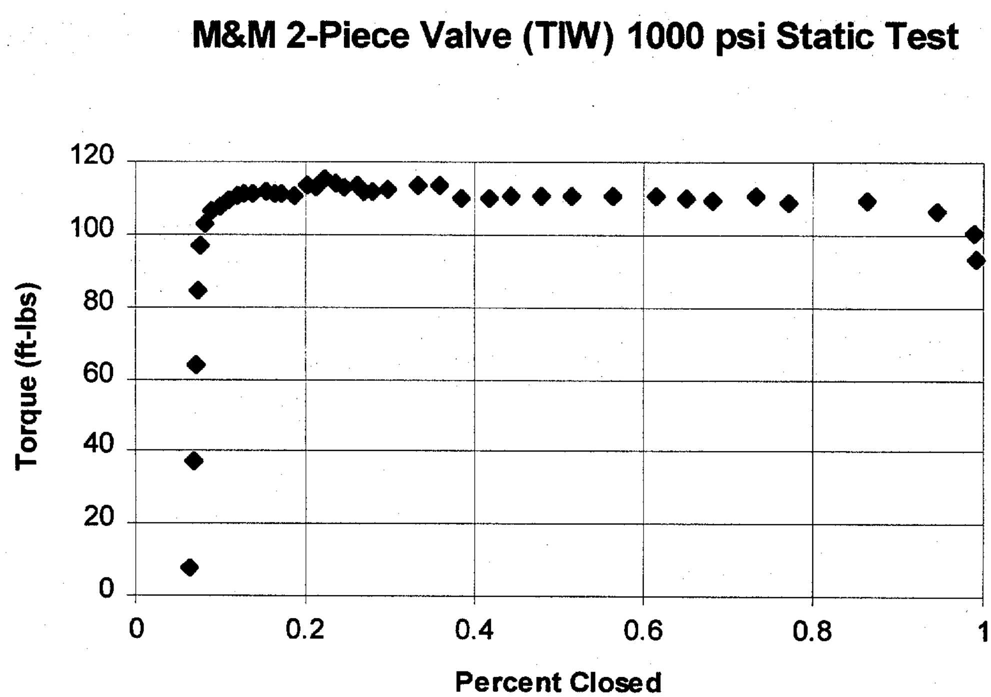
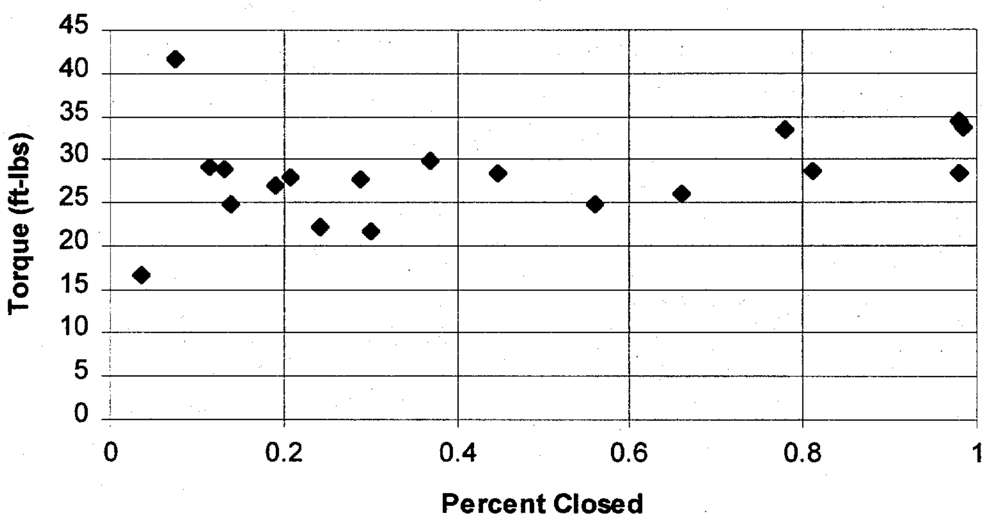


Figure 20: 1000 psi Static test results.

M&M LiteTorque Valve 2000 psi Static Test



M&M 2-Piece Valve (TIW) 2000 psi Static Test

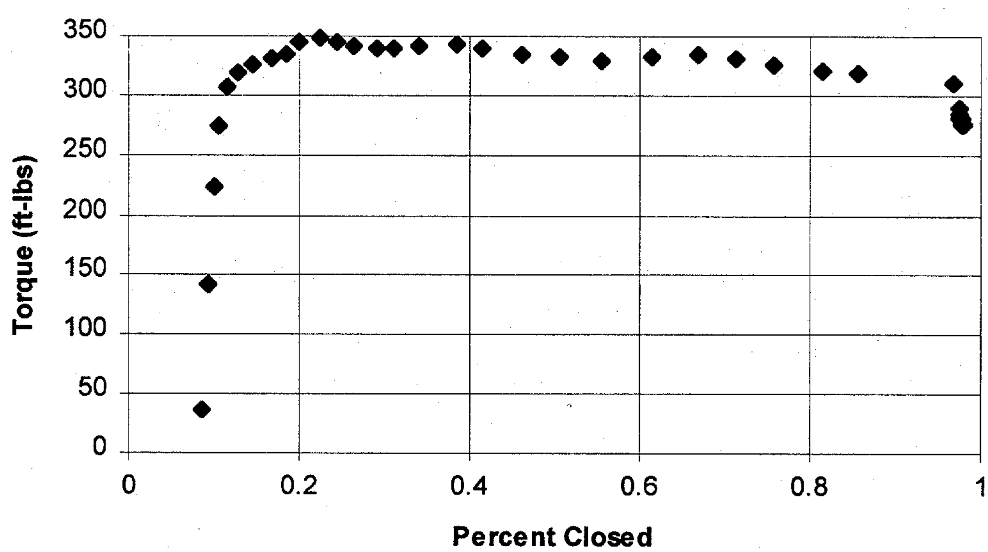
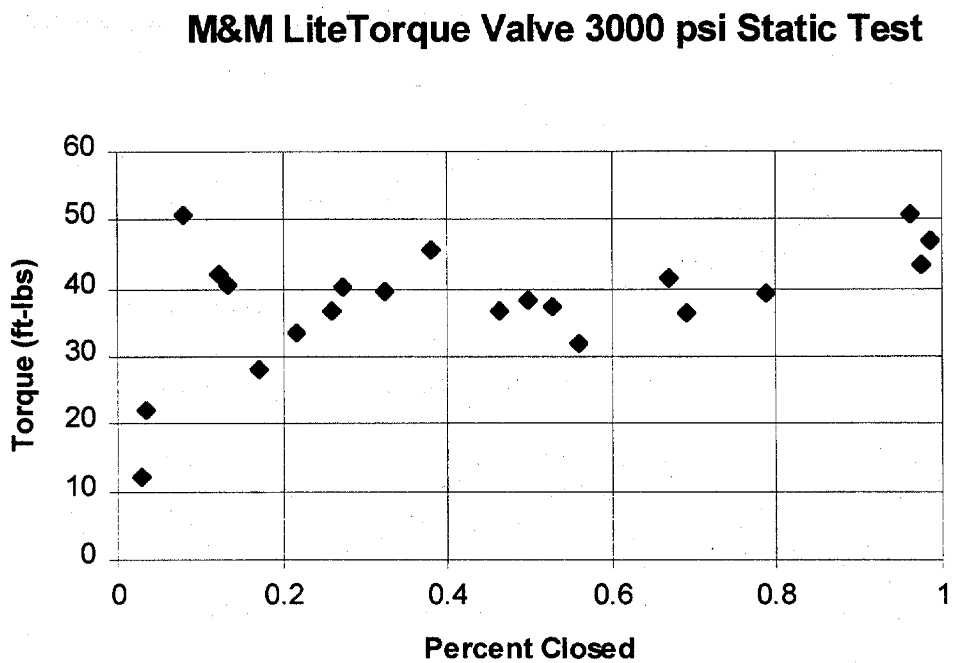


Figure 21:2000 psi Static test results.



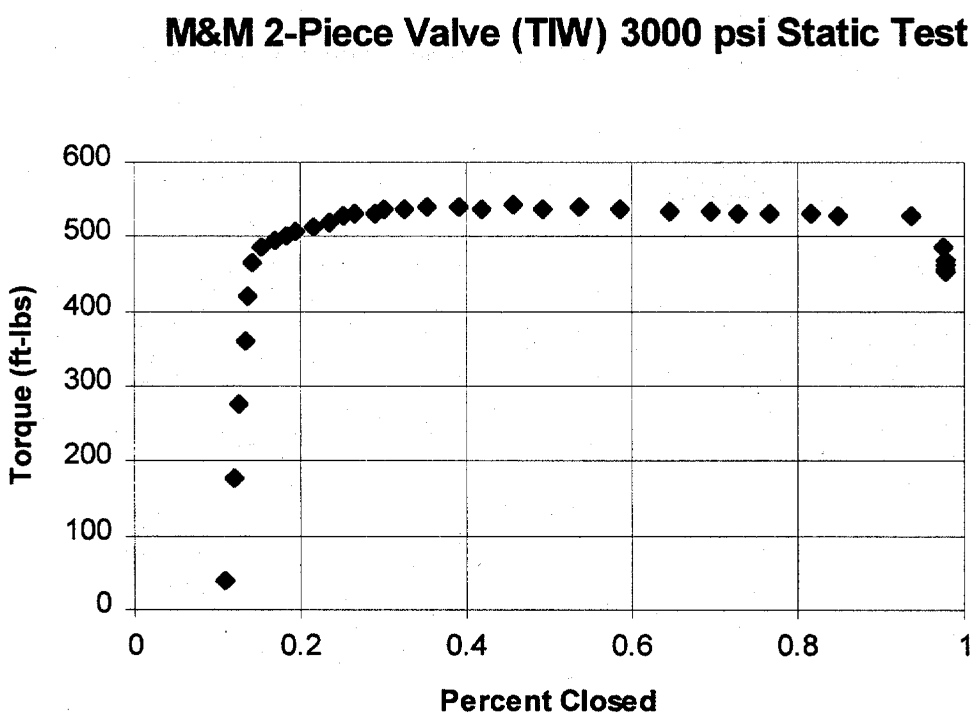


Figure 22: 3000 psi Static test results.

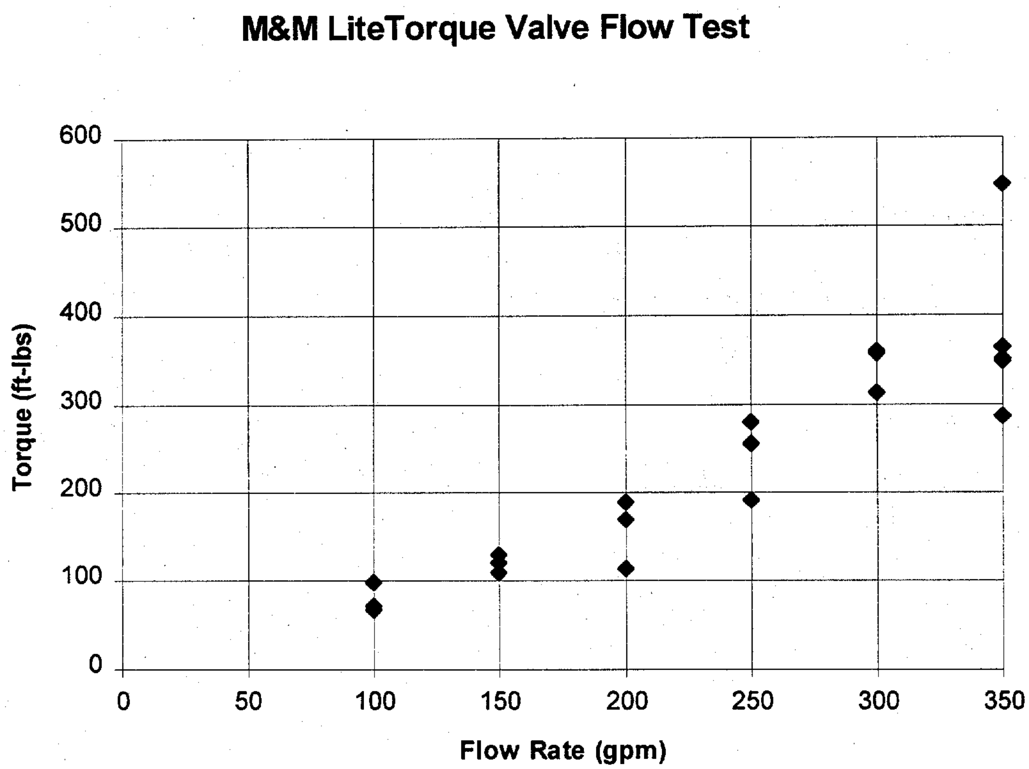


Figure 23: LiteTorque flow test results.

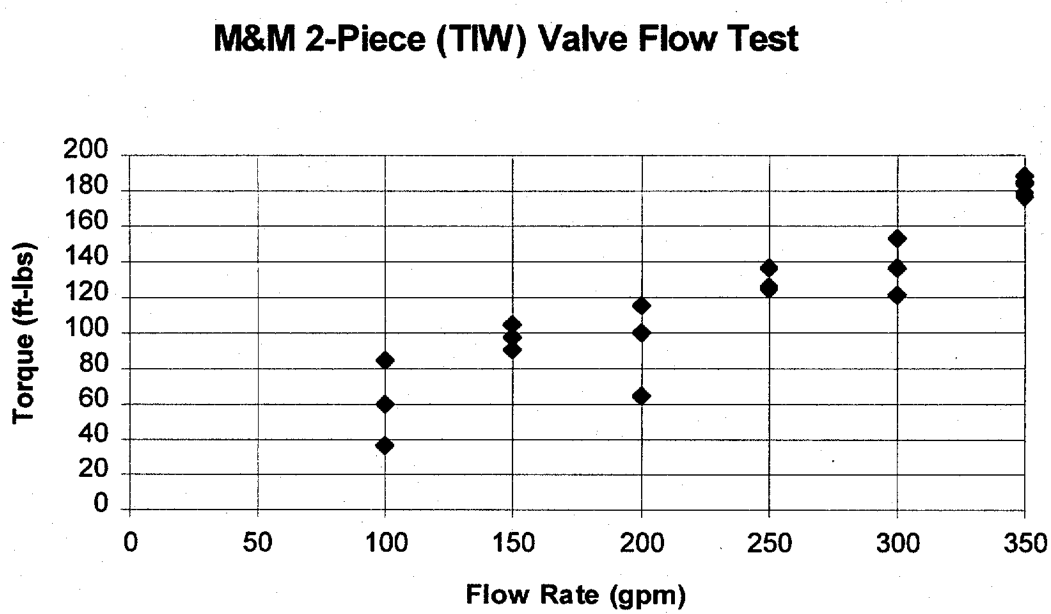


Figure 24: Two-piece flow test results.

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2. Tarr, Brian A.: "Research Targets Drillstring Safety Valve Improvements," *Gas Tips* (Spring, 1996).

RESEARCH TARGETS DRILL STRING SAFETY VALVE IMPROVEMENTS

by

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Research Targets Drill String Safety Valve Improvements

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Dependable drill string safety valves are critical to the prevention of blowouts. Gas Research Institute (GRI) has joined with producers and equipment manufacturers to develop a new generation of rigorously tested valves that meet the standards of today's gas drilling projects.

The widening search for natural gas at greater depths and in less familiar locations is increasing the chances drillers will encounter unexpected subsurface pressures. This means the rig equipment designed to control these pressures will be put to the test more frequently and under more severe conditions. One of the weakest links in a rig's pressure control system is the drill string safety valve (DSSV), or "kelly cock." In certain situations, the proper functioning of this simple ball valve can mean the difference between a gas kick being either one more entry on the driller's log or a blowout that threatens life, property, and the environment.

Gas Research Institute (GRI), in collaboration with the *Mobil Exploration and Production Technical Center (Mobil)*, is encouraging the development of new drill string safety valves that address the operational and safety-related shortcomings of current designs. This effort includes the manufacturing of a new design prototype and the comprehensive testing of this new design along with currently available models.

Testing results completed to date have provided valuable information to manufacturers and have helped validate the need for this type of performance testing. Presently the manufacturers of current generation valves are redesigning their products to improve performance.

DSSV Key to Blowout Prevention

In a conventional drill string the DSSV, a valve located between the kelly and the swivel, provides a means for closing off the drill string to prevent upward flow. A second, lower DSSV may also be placed at the bottom end of the kelly, to provide redundancy. A third valve is also kept on the drill floor, to be used in the event that the well begins flowing when the kelly has been set aside while the pipe is being tripped. In this case, the valve must be "stabbed" into the box end of the drill pipe hanging in the rotary.

If a kick occurs, these safety valves must be capable of holding pressure inside the drill string as the kick is controlled. They must also be able to be closed manually when necessary. In some situations, the lower valve may be run back and forth through the closed blowout preventer stack, as the drill string is "stripped" into the hole under pressure. Under these circumstances, the safety valve must be capable of withstanding external pressure as well as containing internal pressure.

The High Cost of DSSV Failure

In the majority of kick situations there is no need to close the lower safety valve, the upper safety valve, or the stabbing valve. Flow from a kick normally travels up the annulus rather than through the drill string. Since only 1 in 200 kicks taken in deep wells results in flow up the drill string, and since there is only one kick taken per well on average, there is only a 0.5 percent chance that a DSSV will be required to perform on any given well. The cost of failure, however, can be very high. Direct costs of a blowout can range from hundreds of thousands of dollars to more than $100 million in the case of an offshore, underground blowout. Environmental costs, although harder to calculate, can be even more serious. A conservative estimate places the average direct cost of all types of problems with safety valve performance at about $20,000 per well.

Producer Experience Prompted Evaluation

Mobil began a DSSV review in 1993, after experiencing problems with leakage through the valve stem seals on drill string safety valves that were stripped into a well under pressure. This review, tasked with establishing the capabilities of various valves and investigating the extent of the problem among a variety of manufacturers' products, revealed that the majority of manufacturers were unaware of the design requirements for ball type DSSVs used in well control operations involving stripping. Indeed, it was discovered that American Petroleum Institute (API) specifications do not directly address these requirements. The 1994 edition of API SPEC 7 (*Specification for Rotary Drill Stem Elements*) included no functional performance or prototype testing requirements for DSSVs.

In March 1994, as a follow-up to the review, a DSSV Failure Frequency Questionnaire was sent out to *Mobil* affiliates and to a number of other operators. Thirteen majors and large independent operators completed questionnaires and showed an interest in *Mobil's* effort to address DSSV problems. The questionnaire results indicated that many operators had experienced less than satisfactory DSSV performance, in particular with failure to seal against pressure from below and failure to open when under pressure due to high torque. Other problems included:

- Failure to seal against pressure from above
- Failure to seal against outside pressure when stripped into a well
- Failure to close due to high torque when throttling mud backflow
- Failure to seal due to erosion from abrasive flow.

In July 1994, *Mobil* proposed and received approval to form an API Task Group to develop appropriate DSSV functional specifications for inclusion in the next revision of API SPEC 7. It was envisioned that the new specifications would categorize DSSVs into two classes: Class I valves intended for surface use only (e.g., as kelly valves); and Class II valves that could be safely stripped into a well under pressure.

Current Project to Complement Task Group Effort

GRI and *Mobil* began this project to complement the work of the API Task Group by providing actual performance test data for two DSSVs specifically designed as Class 2 valves (suitable for stripping) but having the capability of also meeting the performance expectations outlined by operators. For instance the valve must be repeatedly operable in an abrasive mud environment, manually operable under mud backflow or with high internal pressure, and gas tight at high pressure.

The project was designed to be carried out in two parts, the first being to contract with two manufacturers to supply valves for testing. *Hi-Kalibre Equipment Ltd. (Hi-Kalibre)* was contracted to supply and shop test a 10,000 pounds per square inch (psi) working pressure, 7 in. OD x 2 13/16 in. ID DSSV for testing. This size and rating was chosen to match the typical requirements for U.S. deep gas drilling operations and is the same model as used in the *TESCO Corporation* portable top-drive. A second contract was made with *ITAG Maschinenfabrik Bohren und Aufwältigen Erdöl und Erdgas (ITAG)*, to build and shop test a 10,000 psi working pressure, 7 in. OD x 2 13/16 in. ID new design, prototype DSSV. ITAG had already progressed their prototype design to the stage of building and field testing a 7 3/4 in. OD upper kelly cock version, and the valve built for this test program incorporated refinements based on field testing of the larger prototype.

The second task was to contract with *ITE Engineering Gmbh*, an independent testing facility at the Institute of Petroleum Engineering at the Technical University of Clausthal, Germany, to evaluate the new generation valve supplied by *ITAG* along with the field proven valve supplied by *Hi-Kalibre*. The evaluation testing protocol was based on the draft proposed specifications provided by the API DSSV Task Group, which was chaired by *Mobil* and included representation from drilling contractors, manufacturers, testing and analysis companies and industry well control experts.

Manufacturers Committed to Testing Program

Both *Hi-Kalibre* and *ITAG* are committed to demonstrating they can supply valves that meet the operational requirements specified. *ITAG*, a manufacturer of industrial ball valves for high pressure petrochemical service, has developed a radically new valve design that addresses the high torque problem associated with closure under flow. The *ITAG* valve will be ready for testing this spring, after a trunnion-related failure during testing in late 1995 led to some design refinements.

The testing was designed to evaluate the following operational performance requirements not included in the current API specifications:

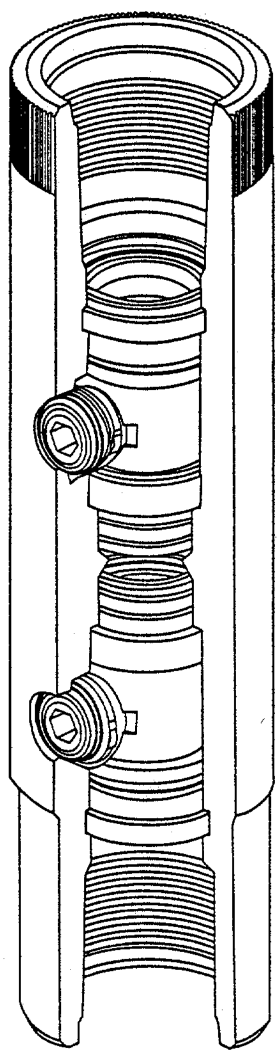
- Holding pressure from above and from outside (required for stripping operations)
- Sealing after repeated operation in abrasive mud
- Sealing over a temperature range of 14° to 194° F (-10° to 90° C)
- Closing on flow and opening under pressure with manageable torques
- Gas tight sealing.

Results of Testing Show Current Valve's Strengths and Weaknesses

Building of the necessary fixtures and fittings to conduct the testing at *Clausthal ITE* was completed in October 1995 and the *Hi-Kalibre* valve was subjected to the complete test schedule in November 1995.

Hi-Kalibre's portable top-drive style DSSV supplied for testing was a tandem ball type with box-by-box NC50 5 in. drill pipe connections (Figure 1). Both valves in the assembly have a floating ball turned by two opposing operating stems. The upper valve is designed for

Figure 1: Cutaway View of Hi-Kalibre DSSV



either remote or manual operation and the lower valve is designed for manual operation only. For manual operation a hex wrench is inserted into one of the corresponding hex nut operating stems to rotate the ball a quarter turn to either the fully open or fully closed position. In the testing program a hydraulic actuator was used to simulate manual operation with 200 foot pounds (ft-lbs) of torque being applied to the end stops. To permit external pressure to be applied to the valve, an external pressure sleeve was fabricated (Figure 2).

The testing program was broken down into seven phases:

I. Initial seat and seal leak test with water and nitrogen
II. Mud solids contamination test
III. Repeat seat and seal leak test (reduced scope)
IV. Operating test - closing on flow
V. Operating test - opening under pressure
VI. Repeat seat and seal leak test (expanded scope, includes tension)
VII. Post testing examination.

The results of each phase are highlighted below.

▸Initial Seat and Seal Leak Test

This test was designed to establish if the valve could satisfy the requirements of Class II service, verify the operating temperature range, and determine if the valve could be classified as "gas tight." The results proved that the *Hi-Kalibre* valve design could be classified as suitable for surface and downhole stripping applications (i.e., it held 10,000 psi working pressure from both below and above and 2000 psi from outside, at ambient temperature with water). The valve also qualified as suitable for service over the temperature range of 14° to 194° F; and, since it sealed bubbletight at full working pressure, qualified as gas tight.

▸Mud Solids Contamination Test

This test was designed to establish if any loss of sealing integrity would occur due to operating the valve as a mud-saver valve. This is a common practice when two DSSVs are employed, one of them is closed to prevent mud spillage onto the rig floor each time a connection is made. To simulate the mud-saver application, a 16 pound per gallon (ppg), sandy, waterbased mud was circulated through the valve for 100 hours in the normal mud flow direction and the valve was operated 500 times. The mud was formulated with fresh water, 2 percent by volume 120 mesh sand and bentonite. A flow-loop was used to flow mud with a temperature of 150° F and a pressure of 1000 psi at 100 gallons per minute (gpm) through the valve. Each time the valve was operated both open and closed, the mud flow was stopped. The actuator had a cycle time of approximately 2 seconds to simulate normal manual operation speeds. The torque required to close and then reopen the valve was recorded.

This test phase proved that, as supplied, the *Hi-Kalibre* valve could be operated manually for 500 close and open cycles in a sandy mud without a serious increase in torque. At the same time, good alignment of the ball was maintained in the indicated open position when a torque of 200 ft-lbs was applied during those cycles.

▸Repeat Seat and Seal Leak Test

A repeat seat and seal leak test phase proved that after simulated use as a mud-saver valve, the *Hi-Kalibre* valve could not provide water or gas tight sealing at working pressure applied inside from top or bottom at ambient temperature. Apparently, either the ball and/or seats suffered damage in the Phase II testing or trapped mud solids were interfering with sealing. However, the valve could provide water and gas tight sealing from outside at ambient temperature (i.e., the stem seals were still fully effective).

▸Operating Test - Closing on Flow

Failure to close on a backflow from the drill string was a common complaint mentioned in the industry survey. This phase of the testing was to determine the torque required to close the valve and shutoff a flow of 16 ppg, sandy, waterbased mud. Two flow rates (100 and 200 gpm) were used to establish a relationship between backflow rate and torque required to close the valve. A closure speed of 2 seconds was used to simulate manual operation. A bypass line and choke arrangement was used to limit pressure buildup to about 2000 psi when the valve was closed.

Between 420 and 520 ft-lbs of torque were required to close the valves, depending on the flow rate (Table 1). Out of six tests, in only one of the 100 gpm flow cases was it possible to reopen the valve. While closing, the torque increased rapidly during the last 10 degrees of stem rotation. Similarly, for the one test where the valve was opened successfully, the torque dropped off rapidly during the first 10 degrees of stem rotation. Note that 400 ft-lbs torque is considered the upper limit for manual operation in the proposed revised API specifications. This corresponds to a maximum recorded torque of 435 ft-lbs due to stem friction.

This test proved that after simulated use as a mud-saver valve, the *Hi-Kalibre* valve could only be closed manually (i.e., recorded torque less than 435 ft-lbs) on mud backflow of 100 gpm or less, and could not be reopened manually.

Table 1: Phase IV Testing Results (Closing Against Flow)

Mud Backflow Rate (gpm)	Hi-Kalibre Start Closing Torque (ft-lbs)	Hi-Kalibre Max. Closing Torque (ft-lbs)	Hi-Kalibre Reopening Torque (ft-lbs)*
100	80	420	>700
100	80	420	657
100	80	460	>700
200	80	520	>700
200	80	510	>700
200	80	490	>700

* Reopening was with approximately 2000 psi differential pressure from below

▸Operating Test–Opening Under Pressure

Abnormally high torques that prevented manual operation when attempting to

Figure 2: Schematic of the DSSV Test Fixture

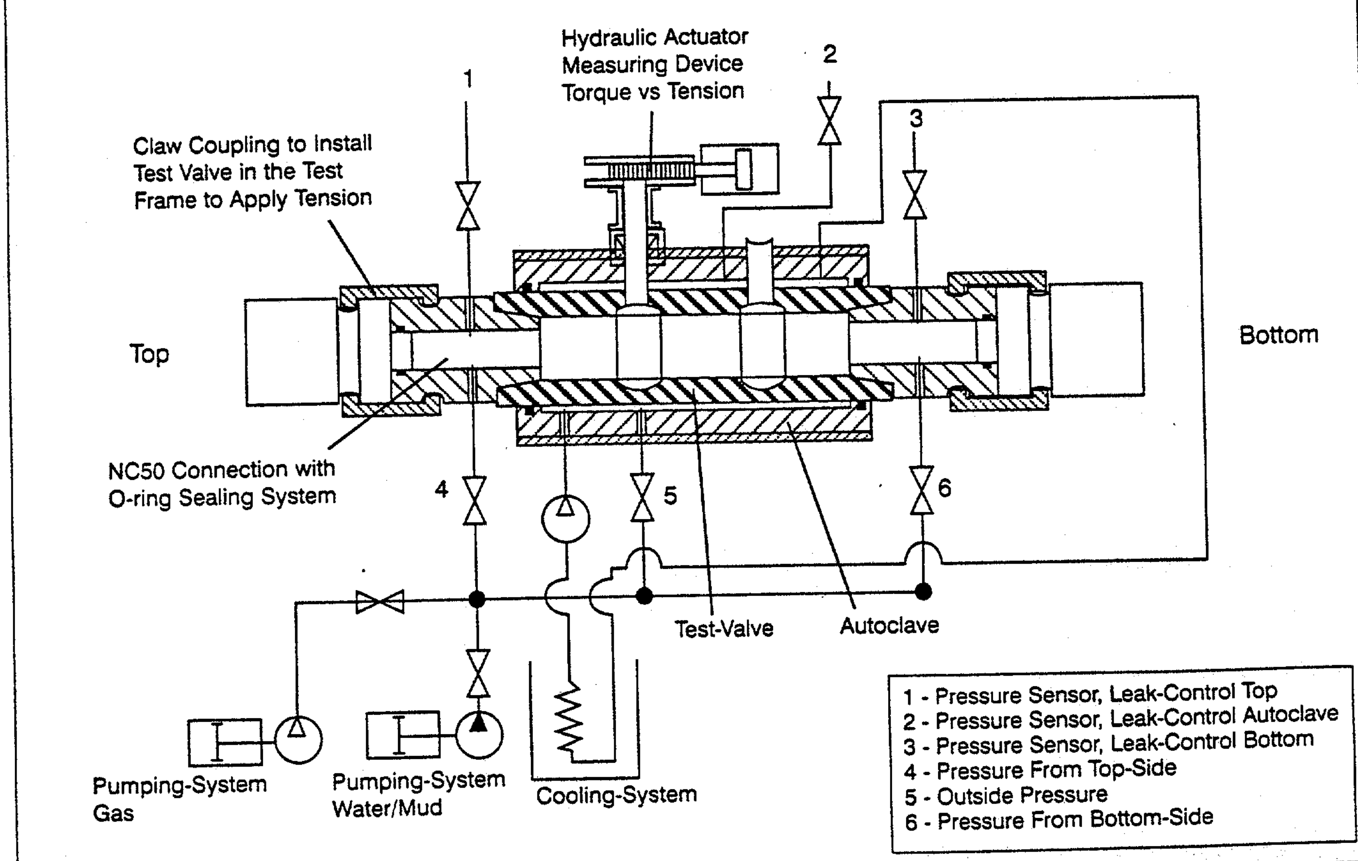


Table 2: Phase V Testing Results (Opening Under Pressure)

Pressuring Fluid Type	Pressure On Top (psi)	Pressure On Bottom (psi)	Hi-Kalibre Torque (ft-lbs)
water	2000	0	469
water	0	2000	>700
water	10,000	10,000	433
water	10,000	8000	>700
water	8000	10,000	660
16 ppg mud	2000	0	>700
16 ppg mud	0	2000	>700
16 ppg mud	5000	5000	373
16 ppg mud	10,000	10,000	>700
16 ppg mud	10,000	8000	>700
16 ppg mud	8000	10,000	>700

open ball-type DSSVs with high pressure inside the valve were also reported in the industry survey. This phase of the testing was designed to determine the torque required to open the valve under a variety of internal pressure conditions.

The results showed that after simulated use as a mud-saver valve, the *Hi-Kalibre* valve could be opened manually with equalized pressures up to 10,000 psi with water and up to 5000 psi with sandy, 16 ppg mud. However, the valve could not be opened manually with a differential pressure of 2,000 psi across the ball, regardless of the absolute pressures or the test fluid (Table 2).

Note that these results were somewhat surprising, as torques measured by *Hi-Kalibre* on a new valve with water indicated much lower values. This suggests that internal damage and mud solids fouling sustained during the Phase II simulated mud-saver valve testing contributed to the high torques seen in Phases IV and V.

▸Repeat Seat and Seal Leak Test

In this final testing phase, tension was included to establish if the stem seal system integrity was dependent on tension applied to the valve body, or to temperature and tension. Results proved that after simulated use as a mud-saver valve, the *Hi-Kalibre* valve could provide watertight sealing from outside at ambient temperature with 500 thousand pounds (klbs) of tension applied to the valve body. However, the valve could not provide watertight sealing from outside at high temperature (189° F) with 500 klbs of tension applied to the valve body. The stem seals failed.

▸Post Testing Examination

After testing, the *Hi-Kalibre* valve was disassembled and examined for wear, stem seal condition, and mechanical distortion. Only minor abrasion-type wear was found on the ball and seats. One of the stem seal O-rings had failed in Phase VI of the testing and this was confirmed by visual examination. Distortion was observed in the area of the valve position stops on the inside end of the stems, which resulted in part of each stem being swollen and no longer a clearance fit in the stem hole. This distortion could explain part of the higher than expected operating torques observed in Phases IV and V.

After cleaning and replacement of the failed stem seal the valve was reassembled and tested with no leakage to 10,000 psi with water. This confirmed the role of the mud solids in preventing the valve from sealing pressure applied from above or below the ball in all the tests after 100 hours of operation. Hence, when used as a mud-saver valve the sealing ability of this type of DSSV can be compromised by mud solids fouling the ball valve sealing surface.

Next Steps

Hi-Kalibre is now redesigning the stem and internal valve stop configuration used in their DSSVs to address the damage that was caused by the 500 close and open operations. *Hi-Kalibre* anticipates that the redesign will reduce the excessive torques seen in the closing on backflow and opening under pressure operating tests. However, the pronounced effects of adhering mud solids on both operating torque and sealing ability are expected to be unchanged.

The new *ITAG* valve design is expected to be ready for testing in May of this year, after problems with the trunnion design have been solved. The results of testing so far have already been valuable to the manufacturers involved and have helped to validate the need for the type of performance testing being proposed to the industry by the API Task Group on Drill String Safety Valve Specifications. ■

For more information contact Mike Weiss, GRI Senior Technology Manager, at 312/399-5484, or Brian Tarr, Mobil Exploration and Production Technical Center, at 214/951-2945.

PROGRESS REPORT ON NEW LOW TORQUE DRILL STRING SAFETY VALVE

by
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OBJECTIVE

The objective of this task of the project was to take a fresh look at design alternatives for drill string safety valves and develop a new valve design with reduced operating torque requirements.

SUMMARY

Drill String Safety Valves (DSSV's) are used to prevent blowouts during underground events in drilling. Several case history reviews of well control events have shown evidence of severe problems with DSSV's. Of those problems, valve lock up is most significant resulting in failure to open or close due to high torque. This progress report describes the design and testing of a prototype low torque DSSV of the ball valve type. The design goal is a constant actuation torque independent of valve internal pressure. Actuation torque for the 6 3/8" OD x 2 1/4" ID valve was measured as a function of differential pressure across the ball and 100% equalized pressure. Results indicate that the prototype valve approaches constant torque operation for 100% equalized pressure. However, differential pressure tests conducted to show constant torque operation were inconclusive. Work on the project is continuing and planned future work is also described.

INTRODUCTION

Drill String Safety Valves are an important part of the overall well control system used to prevent blowouts and are often needed during underground blowout events. Several case history reviews of well control events have shown evidence of severe problems with safety valves. Often, these problems are so drastic that they require the use of freeze plugging techniques to replace the failed valve. Below is a list of common field operating problems for DSSV's.

- Failure to seal against pressure from below
- Failure to seal against pressure from above
- Failure to seal against pressure from outside
- Failure to close due to high torque (valve lock up)
- Failure to open due to high torque (valve lock up)
- Failure to close due to flow
- Failure to seal due to flow erosion

Several efforts are now underway to address these drill string safety valve reliability issues, including an API Task group to consider a new, performance-based classification system, a joint industry project that is testing a new generation safety valve being developed by ITAG (a

German manufacturer) and by Hi Kalibre (a Canadian manufacturer), and a Drill String Safety Valve Test Program at the LSU/MMS Well Control Facility [1].

This paper reports on a project which addresses the failures to close and open due to high torque. A low torque safety valve has been designed, constructed and tested as part of the 1995-96 LSU Mechanical Engineering Capstone Senior Design course. Testing results obtained to date showing required actuation torque as a function of differential and 100% equalized pressure are presented. A second generation low torque safety valve is currently under development as one of the projects of the 1996-97 Senior Design Course. The focus of this on-going and future work is also presented.

BACKGROUND AND OBJECTIVES

Drill String Safety Valves must often be lowered into a well and thus must have a small external diameter with a smooth profile. They must also be easily lifted and screwed into a drill string through which a flow from the well has begun. In addition, the fully open valve must have an unrestricted internal diameter that will allow wireline work and resist erosion by the solids-laden drilling fluid. These design requirements favor manually operated DSSV's over remotely actuated valves for most applications [2]. One significant disadvantage of manually operated DSSV's is that the available actuating torque to open and close the valve is limited by the physical strength of the operator. When the torque required to open or close the valve exceeds the torque applied by the operator, then the valve is said to *lock up*. It is highly desirable that the torque required to actuate the valve does not exceed a value of about 500 ft-lbs.

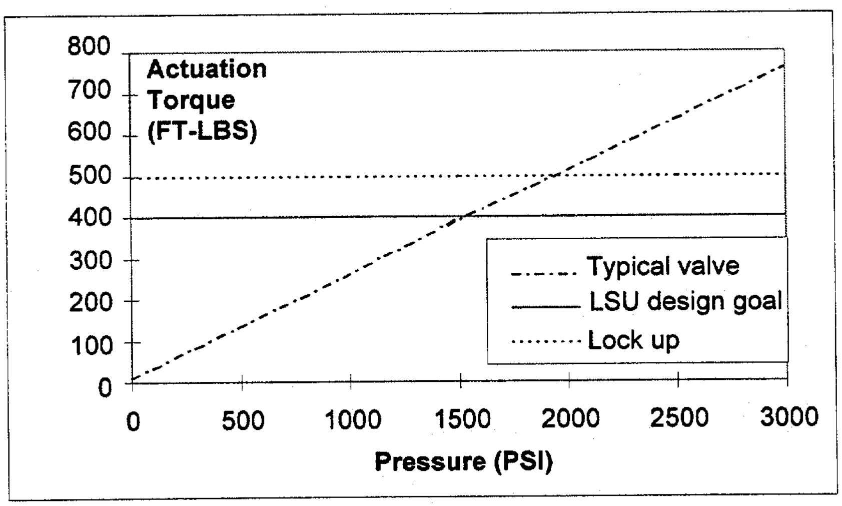

Figure 1: Torque vs. Pressure Curves

After reviewing various possible valve designs, it was concluded that a ball valve offers the best solution to the design constraints. The group was unable to identify any other design concept that offered promise for improved performance. In many ball valve designs, the torque required to either open or close the valve is largely a linear function of internal pressure and/or differential pressure across the ball. As such, at some critical pressure the ball valve locks up due to increased friction between internal components. Figure 1 illustrates the problem of lock up for a typical manually actuated ball valve. An ideal DSSV ball valve design is one where the required actuation torque is constant and independent of the valve pressure, up to the maximum

design sealing pressure. For such a valve, lock up will never occur as long as the constant required actuation torque is below the lock up torque value. Figure 1 also illustrates this idealized concept.

The objective of this work is to design, construct and test a DSSV with an actuation torque vs. differential pressure curve that approaches the idealized, constant torque design. This work focuses upon the low torque ability of the DSSV to open under large differential pressures and to close under high flow conditions. It considers the low torque ability of the DSSV to close under equalized pressure as a secondary design criterion, as much less torque is required for the latter operation.

PROTOTYPE BALL VALVE DESIGN

Ball valve designs commonly employ either a trunnion mounted ball with floating seats or a floating ball with fixed seats [3]. In both cases, the pressure of the fluid being sealed generates the sealing force between the ball and the seats. The seats are then said to be *energized.* Of course, due to the friction between the ball and the seats, and under ideal conditions, the required actuation torque for these designs increases linearly with this pressure. In order to achieve the design goal of an actuation torque independent of differential pressure, the fluid being sealed cannot be used to energize the seats. One way of achieving this performance is to mount both the seats and the ball in the valve body. In this manner all forces which act on the ball and the seats are directly transferred to the valve body. Such a design then requires a separate means to energize the seats with a force large enough to provide adequate sealing up to the maximum rated pressure. This is the basis for the design resulting from this project.

Figure 2 shows a photograph of the LSU prototype DSSV. The valve size is 6 3/8" OD x 2 1/4" ID x 25 3/4" tall with 17-4 stainless steel upper and lower seats and ball. No surface coatings were used on the prototype valve to reduce friction. The valve uses O-rings between the seats and the ball to create the major dynamic seal. O-rings are also used throughout the valve for the secondary static seals. The ball is mounted in a set of sleeve bearings on two sides, through the actuation stem and stem link. The tolerances between the ball, stem link, stem and bearings are kept small such that the ball can "float" only a few thousandths of an inch before engaging the sleeve bearings. The bearing load capacity is a limiting factor for the valve design. Commercially available bearings were reviewed for this service and those with the greatest load capacity for the given space constraint were selected. Even so, the bearing load capacity limits the differential pressure capability of the valve to 4000 psi. This is only

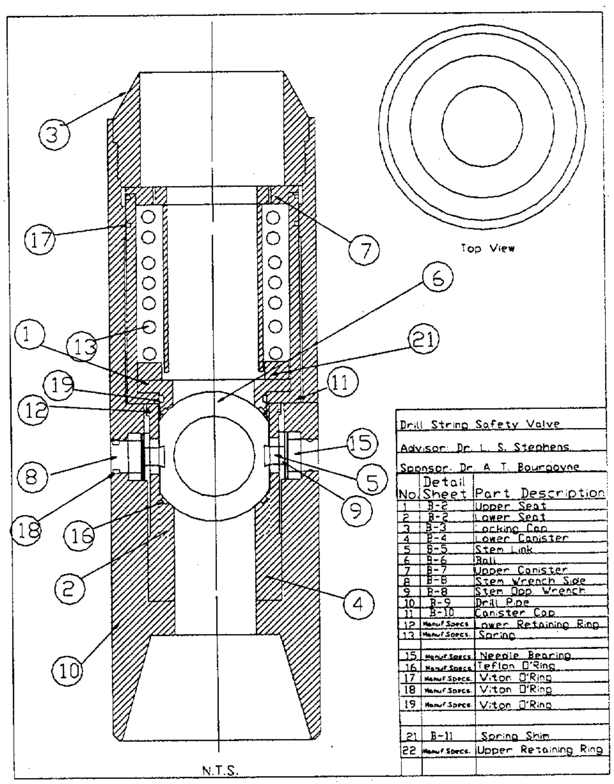

Figure 2: LSU Prototype Low Torque Drill String Safety Valve, 6 3/8" OD x 2 1/4" ID.

80% of the initial target design specification of 5000 psi differential pressure.

The valve design uses a ball housed inside a canister for sealing. The bottom seat is part of the canister itself, while the top seat is a separate component that is loaded and held in place by a helical coil compression spring. This spring provides the force which energizes the top seat against the ball and provides a constant sealing force independent of differential pressure when the valve is sealing from below. For a target design specification of 5000 psi maximum differential pressure, the sealing pressure between the ball and seats is taken as 1.1-1.5 times this value. Based upon simple assumptions regarding the contact area between the seat O-rings and the ball in the loaded condition, the compression spring was designed to provide a maximum force of 4000 lbf. Shims were designed to adjust this sealing force as needed during testing. Figure 3 below shows the resulting force-deflection curve for the spring over three cycles as tested using an Instron machine.

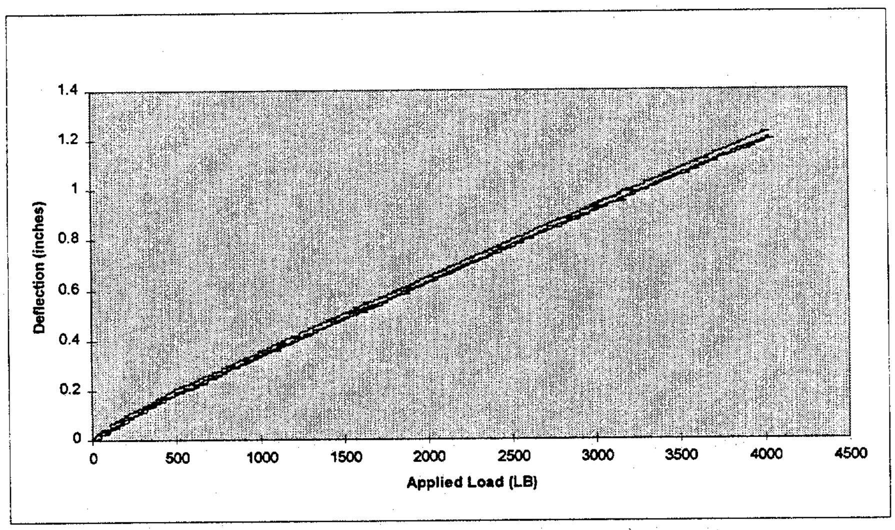

Figure 3: Load vs. Deflection Curve, Top Seat Loading Spring

The canister is held into place by a locking cap which is threaded into the top of the valve body. Therefore, any pressure acting against the bottom of the canister is directly transferred to the valve body through the locking cap. Together, the bearings, canister, spring and locking cap provide a design where the differential pressure contribution to the actuation torque depends only upon the sleeve bearing internal friction. Optimal selection of frictionless bearings then results in a low torque DSSV design when sealing a differential pressure from the below. Another limitation of the design shown in Figure 2 is that low torque operation is lost when sealing pressure from above. This is not considered to be a significant limitation as the pressure when sealing from above can be controlled by the operator. Finally, thrust bearings are mounted on the actuation stems to reduce the friction between internal components due to the pressure difference between the interior and exterior of the valve. This design can be termed a trunnion mounted ball, pseudo-fixed seat design. Table 1 below summarizes the performance specification of the valve as it is presently designed.

Table 1: Resulting Prototype Design: Trunnion Mounted Ball, Pseudo-Fixed Seats

Internal Component Material	17-4 Stainless Steel
Sealing Surface	Viton O-rings
Max. Body Pressure	10,000 psi
Max. Differential Pressure	4,000 psi (Sealing from Below)
Low Torque Operation	Sealing from Below Only
Primary Sealing Surface	Top Seat, sealing from above and below

TESTING AND RESULTS

Three static pressure tests were performed on the prototype safety valve. These were a hydrostatic test on the valve body, a measurement of torque required to open under a differential pressure, and a measurement of torque required to close under 100% equalized pressure. No tests under flow conditions were conducted. All tests were performed using water pressurized by a hydraulic test stand at a local valve manufacturer's facility. All torque readings were made by a calibrated digital torque wrench. The hydrostatic pressure test required the valve body and stem seals to effectively seal twice the maximum allowable working pressure of the valve for 5 minutes. The valve exceeded this performance by sealing this pressure for a 15 minute period. Torque measurements under differential and 100% equalized pressure were obtained as part of the testing procedure outlined below:

1) begin with valve in closed position;
2) pressurize valve from below to the desired level;
3) hold at this pressure for 5 minutes and check for evidence of leakage across the ball;
4) open the valve using the torque wrench to obtain the torque required to open under differential pressure;
5) the valve is now at 100% equalized pressure on both sides of the ball;
6) close the valve using the torque wrench to obtain the torque required to close under 100% equalized pressure.

Torque to Open Under Differential Pressure

Figure 4 shows the torque required to open under differential pressure for the LSU prototype design. Similar data for a commercially available low torque DSSV, tested using the same procedure, is given for comparison and is labeled Valve "A". Both valves are of 2 1/4" ID bores. As was discussed earlier, due to limitations in the bearing load capacity, the maximum rated differential pressure for the prototype LSU DSSV is 4000 psi. The results reflect this pressure rating as differential pressure tests were performed up to this maximum limit.

During these tests, the valve stem for the LSU DSSV yielded under the applied torque at higher pressures. The stem was re-machined, but this difficulty resulted in only four data points for these tests. The results indicate that the actuation torque to open Valve "A" was largely linear while that for the LSU valve varied non-linearly. This suggests that certain components within the valve shifted under pressure due to incorrect tolerance and assembly, and that surfaces

other than the sleeve bearings and O-ring seats were loaded and in contact. Finally, the data does show a cross-over between the endpoints, where at low pressures the LSU DSSV requires more actuation torque than Valve "A" but at high pressures it requires less actuation torque. However, due to the small number of data points, there is not enough data to substantiate this claim. More experimental data is required, both from the LSU valve and similar valves to determine if the new ball design results in a constant actuation torque vs. differential pressure curve. Additional tests are planned after constructing an improved prototype design.

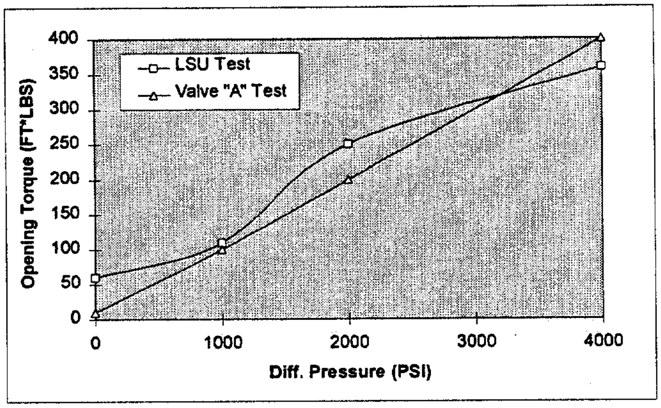

Figure 4: Torque to Open Under Differential Pressure, 2 1/4" ID Bore

Torque to Close Under 100% Equalized Pressure

Figure 5 shows the torque required to close under 100% equalized pressure for the LSU prototype design. Similar data for another commercially available valve labeled Valve "B" are provided for a qualitative comparison. The data for Valve "B" are taken from published catalog curves which were generated using a different test method. Both the LSU valve and Valve "B" are of 2 1/4" ID bore.

This data indicates that the LSU DSSV prototype required a largely constant torque to actuate against 100% equalized pressure. The required actuation torque varied between 60-80 ft-lbs over an equalized pressure range of 0-10,000 psi. This compared favorably to the data taken from Valve "B" product data sheets. This data shows that for 100% equalized pressure, the LSU prototype achieved the goal of an actuation torque which is largely independent of the internal valve pressure.

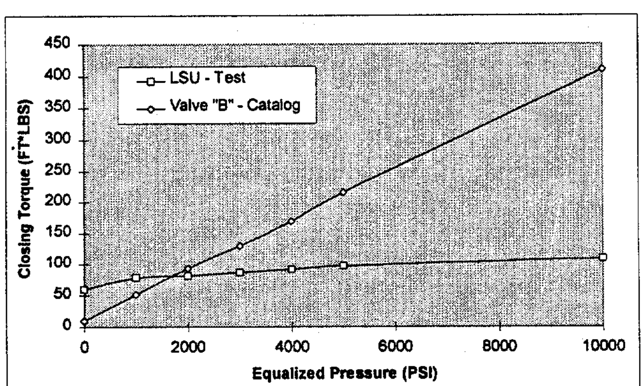

Figure 5: Torque to Close Under 100% Equalized Pressure, 2 1/4" ID Bore

Post Test Valve Inspection

Upon completion of the testing, the valve was disassembled and inspected. Inspection revealed significant galling (adhesive wear where incomplete cold welding occurs, leaving large streaks in the surface) between the lower seat and the ball, the ball and stem link and the stem link and stem. This wear indicates incorrect tolerance and assembly of the parts. Indeed, an assembly review revealed that the O-ring groove for the bottom seat was machined to the wrong size. The wear pattern between the ball and the stem link indicated that the ball was not centered sufficiently. Finally, wear between the stem and the canister windows indicated that the bearing tolerances were too loose and the canister acted as a bearing surface. Each of these deficiencies results in an increased actuation torque for the ball valve as a function of differential pressure, which is the probable cause for the results of Figure 4. These deficiencies will be corrected in future work and should significantly reduce internal valve friction.

CONCLUSIONS AND FUTURE WORK

Both the differential pressure and 100% equalized pressure tests showed that the LSU prototype DSSV required more actuation torque at low pressures and less actuation torque at high pressures than two other similar valves. This trend was very strong in the case of the 100% equalized pressure tests but was weak in the case of the differential pressure tests. Internal inspection of the valve after testing showed assembly and tolerance errors that contributed to the relatively poor performance of the differential pressure tests. In order to substantiate claims that the new ball design approach is valid, the tolerance and assembly errors must be corrected and more testing conducted.

Presently, the 1996-97 DSSV Senior Design Team is assisting with the development of an improved second generation prototype using the information collected from the first team. In addition to correcting the tolerance and assembly errors, this team is assisting in the implementation of changes that should lead to improved performance. The new design should allow the valve to obtain a 5000 psi differential pressure rating.

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Further Work on Low Torque DSSV Project

- **Investigate methods to increase the pressure rating of the low torque safety valve**
  - alternative trunnion bearing designs for high pressure valves (goal: 15,000 psi)
  - alternative top spring loading designs
- **Modify Prototype design for low torque, *firesafe* design**
- **Address other failure mechanisms (erosion, sealing capability)**
- **Evaluate design to minimize cost of valve**
- **Test to New API Specifications**

POST ANALYSIS OF RECENT BLOWOUTS

by

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OBJECTIVE

The objective of this task of the project is to develop training modules to support industry training for handling underground blowouts. Because of the complexity of most underground blowout control operations, a team approach is needed. Field personnel generally must receive considerable engineering support from the office to develop a kill plan. The modules being developed will cover training needs of both field and office personnel. The purpose of this report is to summarize our progress made in this area.

INTRODUCTION

An underground blowout occurs when formation fluids flow from one subsurface zone to another in an uncontrolled manner. The results range from being indiscernible to catastrophic. An underground blowout can result in minor transfers of fluids that may never be identified or in flow which reaches the sea floor or ground surface. If the flow reaches the surface, a crater, loss of equipment, and sometimes loss of life may result. A principal difficulty in handling underground blowouts is the difficulty in diagnosing and understanding what is actually happening in the subsurface. Consequently, a major uncertainty once an underground blowout is identified is whether a significant risk of surface cratering exists. Another major difficulty is the lack of a systematic approach to analyzing and controlling the flow. This is complemented by the relative lack of coverage of underground blowouts in conventional industry well control training. This difficult and complex subject usually accounts for less than 5% of the time or material covered. Some schools include a brief description of a "low choke pressure" method as a reaction to high casing pressures or partial lost returns during a kill operation. Attempting to apply this method will frequently allow additional influx that increases the risk of an underground blowout occurring. Overall, we have shortcomings in all areas relating to underground blowouts: training, prevention, identification, diagnosis, control, and verification of control.

The general response to an apparent underground blowout seems to be a trial and error approach. Both diagnosis and solutions may be conducted in this manner. Control operations frequently start by trying to cure what is perceived to be the most likely problem and only revert to attempting to define the real problem after the first trial solutions fail. Control methods that are commonly attempted include:

1. pumping LCM, gunk or cement to the loss zone in an attempt to regain conventional control,
2. bullheading kill fluids into the loss and/or producing zones,

3. a dynamic kill using frictional pressure loss and fluid density to increase wellbore pressure opposite the producing zone,
4. a weighted slug below the loss zone to overbalance the producing zone,
5. a "sandwich kill" that bullheads kill fluid from both above and below the loss zone,
6. a barite pill or cement plug to isolate the producing zone from the loss zone, and
7. a bridge plug set to isolate the producing zone from the loss zone, or more commonly just to provide a subsurface closure while surface equipment is changed or pipe is run in the well.

Successful application of any of these methods usually requires an implementation strategy that includes:

1. knowledge of the location, pressure, and flow characteristics of the producing and loss zones and the flow path,
2. definition of a kill approach and sequence that fits the diagnosed situation and the ultimate objective,
3. design of fluid constituents, densities, volumes, placement, and rates to achieve the intended approach,
4. acquisition of the necessary people, equipment, materials, fluids, and instrumentation to implement the design,
5. a plan for conducting the operation with predicted outcomes, usually pressures, to allow monitoring whether it is succeeding,
6. an agreed upon basis for stopping the planned operation, analyzing it, and defining an alternate approach if the plan is not progressing as predicted,
7. a method for confirming that progress landmarks are achieved before continuing to the next step, and
8. a method for finally confirming that the ultimate objective, usually permanent isolation of the producing zone from potential loss zones, has been achieved before considering the operation complete.

It should be evident from this list that engineering analysis and design; operational organization, implementation, and control; and the coordination between operations and engineering are all important to achieving success.

Although some well control manuals, such as Murchison[3], Abel[4], and Kelly, Bourgoyne, and Holden[5], provide guidelines or flowcharts for a few specific situations or control approaches, no accepted, systematic method for conducting this process currently exists. However, we can define some general processes like the one above and apply them to actual case histories. This provides a practical, if not necessarily comprehensive, basis for demonstrating why conducting the process carefully is important and what some of the critical "turning point" issues are that must be addressed. Our prototype approach for accomplishing this is the training module described in the following sections.

TRAINING MODULE DESIGN

The prototype training module has been designed to apply a philosophy of learning through practical problem solving on real situations. It emulates hands-on learning with what we call "mind-on" learning. Specifically it requires the training participants to make their own decisions about how to handle each phase of an actual underground blowout experience, qualitatively consider the possible results, and then compare their ideas to the actual results achieved. Conceptually, the participant is expected to act as if they were part of the drilling organization handling the underground blowout at the time it occurred.

The decision points in the actual well control experience provide the practical problems to be solved in the training module. These decisions that control every well control incident are organized by the phases of the well control process. These phases are essentially the sequence of major events that can occur in a well control incident. This sequence of phases and the related decisions then provides a logical organization for explaining the sequence of events in a well control incident. The sequence of phases used for the training module are:

1. Planning and preparation--actions and decisions determining well design, safety factors, and contingencies
2. Prevention--actions that identify and decisions that correct potential causes of kicks
3. Detection--actions leading to detection and decision that a kick is indeed occurring
4. Reaction--decision whether and how to react to an apparent kick
5. Control--decision on what control method to use, how to determine if it is working, and when to change it
6. Recovery--decisions leading to recovery of control (correcting the UGBO) if it was lost
7. Confirmation--decisions on whether and how to confirm that control was regained

This sequence generally coincides with the chronological sequence of events. Consequently, it provides an easily followed path through the decisions that caused operations to evolve from routine activities (with prevention being the primary focus) to an underground blowout. For the cases we have now, this sequence also provides the path back through the decisions and recovery efforts that are eventually successful in returning the well to routine operations. By applying the subsection learning sequence described below to these key decisions, we give the participant the chance to analyze and make the decisions for themselves and to evaluate and learn from their decisions.

The process of participants making a decision and then analyzing it conceptually in the context of the decision implemented in the actual well creates a subsection of the training module. These subsections can be thought of as "minds-on" interactive learning exercises. A typical sequence of events in one of these exercises is:

1. A point in the well control process is reached where an operational decision must be made, i.e. a turning point or decision point, such as which kill method to use, whether to

continue a method that is not performing as expected, or whether the well is safe to return to routine operations.
2. The current status of the well is described as well as it is known.
3. The participants "brainstorm" potential actions to regain or maintain control of the well.
4. The participants and leader hypothesize the probable outcome of those actions.
5. The actual action taken is described, and if different than the proposed actions, its probable outcome is hypothesized.
6. The results that actually occurred are reviewed and compared to our hypotheses. Our "mistakes" are discussed to identify probable causes and potential corrections. Implications regarding the probable success or failure of the alternative actions that were identified are discussed.
7. Our "experience" is reviewed. In particular, factors that contributed to success or failure or that could have corrected our course of actions are identified, so that they become part of our common knowledge for addressing subsequent decisions.
8. Then the process is repeated at each important new decision point until the well is successfully returned to routine operations.

Each major decision in a well control incident can be addressed with the preceding sequence depending on its importance and the quality of the information relating to it in the case history. The sequence is applied rigorously to the key decisions or learnings resulting from a given case history. It is used in a more abbreviated manner to address all of the documented decision points in a given case history to emphasize cause and effect and the importance of effectively using available resources without requiring participants to analyze every decision.

One of the most critical decisions in every underground blowout experience is how to attempt to regain control and recover from the blowout. This decision would typically be one that is addressed rigorously using the subsection sequence. The analysis of whether the control methods identified during the brainstorming apply to the situation at hand can begin by using another conceptual model. The model defines the general steps involved in the "recovery" phase operations, which are:

1. Establish hydraulic path to zone of concern, if it does not already exist
2. Stop influx
3. Remove influx
4. Regain hydrostatic control
5. Achieve zonal isolation

These are very similar to the steps in conventional well control, but accomplishing them may be significantly more difficult. Not every situation will require every step and some will allow steps to be combined, but attempting to ignore or combine steps that are most likely required just prolongs and potentially complicates the problem.

The methods proposed by participants for regaining control can also be considered using the required elements of a successful implementation strategy described in the previous section. If a method will not achieve a necessary step in the well control process, if its results cannot be predicted at least qualitatively, if the resources to implement it are unavailable, if it cannot be controlled, or if it precludes corrective action in the event it fails, it should be altered or rejected.

Considering and comparing the alternatives relative to these issues reinforces the need for the proposed solution to be developed using the effective cooperation between operational and engineering personnel. A simple flowchart showing some basic requirements for this kind of cooperation is shown in Figure 1 and further explained in a paper by Smith et al[6].

The actual reasons for the success or failure of the methods used in the case history to control the kick and to recover from the underground blowout can then be provided in a logical sequence and context. Understanding these reasons in a practical context are the factual key learnings within the module. They also provide a basis for validating or revising the expected results from the participants' proposed alternatives as well. Although having quantitative or conclusive predicted results for every possible alternative that participants may suggest is impractical, the group can make reasonable conclusions about the success of most alternatives. When this is not possible, the group can acknowledge that the other alternatives might be successful but require real engineering analysis or trial and error experimentation to know.

When a training module is completed, the participants should have drawn their own conclusions about the decisions and causes that contributed to actual blowout and recovery, about more effective ways to avoid and control similar situations in the future, and about the analysis and planning required to select and implement effective procedures. They should also have learned both the basic factual, technical requirements for successfully using the procedures discussed and some of the logical and conceptual requirements for addressing a new problem. Consequently, they should be better prepared for dealing with the difficulties of an impending or on-going underground blowout than if only conventional training had been provided.

LSU will soon be acquiring an advanced rig floor simulator for well control training. This simulator will have a customization capability and will be a beta test site for new developments by the simulator manufacturer. Consequently, it may provide a hands-on supplement to the "minds-on" learning described above. Our training and research wells could be used for a similar purpose, allowing practice of a real operation, such as a dynamic kill or bullheading, to supplement the training module.

Other possibilities being considered are aimed at delivering the training module to a potentially remote audience. These include developing programmed learning modules for PC's that include numerical simulation of the real situations, programmed learning modules to develop logical analysis and decision making skills for underground blowout control by rig site personnel, and establishing access and support for such modules through the Internet.

CASE HISTORIES

Case histories were selected as the means for developing a reliable, factual basis for improved training in handling underground blowouts. Several case histories have been acquired from industry for this purpose. In addition, case histories are also described in some existing well control literature (Murchison[3] and Abel[4]). In general, the examples in literature provide enough information to make and support a key point, but not to develop a full training module. Three relatively well documented case histories have been acquired and are being used in the development of effective training modules.

An "Underground Flow Offshore Texas" is the basis for the prototype training module and is documented in detail in the example below. Figure 2 is a wellbore diagram showing the important features of the well design. The flow resulted after running and cementing a production liner opposite a high pressure gas zone. The attempt to perform an off bottom circulating kill resulted in increased surface pressures and an underground flow that was subsequently isolated but not stopped. Several months later this flow was detected and eventually successfully controlled. The key learnings from this experience are included in the example training module and in Figure 12.

A "South Texas Blowout" is another well control incident that we are analyzing. Figure 13 is a wellbore diagram showing the condition of the well just before it was initially shut-in. This incident began with lost returns while drilling an overpressured gas reservoir with an oil-based mud. A large gas kick was taken while trying to cure the lost returns. The volume of the kick and the presence of a lost circulation zone apparently contributed to the development of underground flow. Eventually, the ineffective attempt to stop lost circulation resulted in excessive pressure on the drillpipe, which ultimately resulted in blowouts up both the drillstring and the casing-drillpipe annulus.

Key learnings from analysis conducted to date on the "South Texas Blowout" are that:

1. the large kick size resulted from not keeping the annulus full and not shutting in immediately when returns were achieved after severe losses,
2. rapid fluctuations in casing pressure after shut in can occur when the mud level in the drillpipe is not at the surface even if no underground flow is occurring, and
3. a water-based cement slurry was more effective in sealing an apparent loss zone than lost circulation material in oil-based mud.

A "Deep Underground Flow" is the third underground blowout data set that we have acquired. A wellbore diagram is included as Figure 14. This incident began during a trip in the hole with a new bit after recovering a core from the production horizon below 20,000'. A slight flow was detected and the well shut in with almost no surface pressure. After continuing the trip and circulating to try to get the mud "back in balance", the well was shut in a second time when it was observed that the pits were running over. The volume of influx was large enough that it caused fracturing at the casing shoe and initiated an underground flow when the well was shut in. The well was ultimately controlled with a high pressure bullheading operation that pumped roughly two well volumes of kill weight mud. Key learnings are:

1. a very small volume of gas influx can go undetected while migrating until its volume expands enough to unload enough mud to initiate flow,
2. questionable kick indications require treatment as if a kick is occurring until proven otherwise, and
3. off bottom well control requires special procedures not addressed in conventional training.

EXAMPLE--PROTOTYPE TRAINING MODULE

The prototype training module has evolved from "The Case History of an Underground Flow Offshore Texas"[7] that was originally presented at the 1991 AADE Advanced Well Control Forum in New Orleans. As such, it was initially intended to be an informative story with some key lessons for drilling engineers and supervisors, who might encounter similar situations. It was subsequently adapted as a training module for rig site personnel who would be drilling additional wells in the same area. The adaptation implicitly followed the concepts described in the section on training module design and is the basis for our prototype training module described herein.

The case history describes the operator's experience drilling two moderately deep, highly overpressured gas wells that were the fifth and sixth wells on a platform offshore Texas. An underground flow occurred in the fifth well after cementing the production liner, but was not detected until after unanticipated kicks were taken in the sixth well. Diagnosis with cased hole logs then confirmed the existence of an underground flow behind pipe in the fifth well. A dynamic kill was designed and was followed by several remedial cementing efforts that were eventually successful in isolating the producing zone from shallower, weaker formations.

The training module focuses on both telling the story in a logical, technically sound context and on the critical decisions that became turning points in the efforts to control the well. Both failures and successes are reviewed. The module introduces the problem with the kicks taken in the sixth well and describes how the conclusion was reached that an underground flow in the fifth well was the most likely cause. It then shows the reproductions of the logs run in the fifth well, Figure 2, that confirm a problem exists. This provides the basis for demonstrating that the remaining discussion is not hypothetical, but a serious problem for both drilling safety and the economic value of the field.

The module then shifts back in time to the planning and drilling of the production interval in the fifth well. An overview of the well design, reservoir and fracture pressures, casing design, and kick tolerance are provided using Figure 3. The practical feasibility of the design is validated by the four previous successful wells, but the critical nature of the well is also evident. This provides emphasis on the planning and prevention phases of well control. That emphasis is continued in the following discussion of the design and implementation of running and cementing the production liner. Loss of returns during both running and cementing operations is identified as a probable turning point issue in the loss of well control. Figure 4 summarizes this situation noting that there was no record that the annulus was kept full and that a drop in fluid level of only 140 feet would have caused an influx of gas. After placing the cement, the drillstring was released from the liner, and the well was reverse circulated. After reversing out, the well was identified as flowing and was shut-in with 150 psi on both the drillpipe and the annulus.

The decision concerning how to control this pressure and evidence of flow is the first critical turning point addressed using the full "minds-on" learning sequence outlined earlier. Diagnosing the cause of the pressure and flow and selecting and implementing a control procedure are exactly the kind of actions for which rig site personnel are expected to have the primary responsibility. The potential for the pressure being caused by flow back from an induced fracture can be considered, diagnostic methods defined, and the conclusion that a kick has occurred confirmed. The alternative control actions can be identified and discussed, and then compared to the actual actions taken in the well. In actuality, an attempt was made to remove gas from the well by circulating using the driller's method as shown in Figure 5. If not already analyzed, this alternative can be discussed before revealing its results. Those results were increasing pit gain and annulus pressure as shown in Figure 6. If the group has not identified the probable failure of this method, the reason for failure can be explained. It provides the key learning that off-bottom control methods are more complex, and require more engineering, than conventional well control.

This provides the opportunity to make another key decision regarding how to regain control. The learning sequence can be applied again to a situation where the risk to the rig and its personnel has become significant and "conventional" well control is obviously ineffective. Participants' ideas can be compared again to the actions actually taken and conclusions drawn about why various approaches might or might not succeed. The actual results are shown in Figure 7. The practicalities of bullheading large volumes at relatively high pressures can be reviewed if not previously brought out in the discussion. The pressure on the 9 5/8" by 11 3/4" annulus is also pointed out. The key learnings are that even a near failure can be reversed and improved and that bullheading can be an effective way to regain hydrostatic head, reduce surface pressures, and improve safety margins.

At this point the pressures on the well have been reduced and another decision must be made. The learning sequence is applied in a cursory fashion to the decision whether to continue bullheading in an attempt to kill the well or to squeeze the liner top to eliminate pressures inside the well. These alternatives are critiqued, and the field results of squeezing cement into the liner top shown in Figure 8 are reviewed.

The next critical decision is whether the liner top squeeze has successfully controlled the well. The learning sequence can be applied again beginning with brainstorming ways this question might be answered. The methods can then be evaluated relative to what they really measure and how that relates to flow conditions that might be possible in the well. If participants were paying attention at the beginning, they will remember the logs at this point. This is a good opportunity to bring out the value of both technical methods like logs and operational methods like pressure tests to answer the question more completely than either one by itself can. The actual success testing the liner top and the decision that no further evaluation was necessary lead us back to the point where the story began with discovery of the underground blowout affecting the adjacent well. The key learning is that there needs to be real confirmation that control has been reestablished before saying that a well control operation is complete.

Knowing that flow exists behind pipe, the final critical decision is how to regain control. The learning sequence can be applied again to compare the alternative methods listed earlier for application to this situation. This should lead to the more specific questions: "Should the well be killed or bridged and with what?" We are also faced with the question of how to reestablish a flow path to the area of flow and minimize the increase in risk to the rig when we do. Answering these questions requires the integration of engineering and operations again. The predictions of maximum possible gas flow rate and minimum required mud kill rate shown in Figure 9 show how engineering can help provide the answers. The key learning is that, with time and engineering resources, the success or failure of a particular approach can be predicted, allowing design corrections before making a mistake.

Knowing that a dynamic kill for even worst case flow was feasible, communication with the annulus was reestablished through the casing shoe. Mud and then cement were pumped resulting in a partial cement job on the producing interval. Results were confirmed with logs showing that there was potentially still some flow and that zonal isolation had not been achieved. The casing was perforated and multiple additional cement jobs were placed at the top of the producing sand until it was isolated from the shallower annulus and loss zone as seen in Figure 10. Learnings were that cement should be expected to move with the fluid flow, that tracers can confirm cement placement, that achieving a seal or bridge is very difficult in the presence of any flow, that leaving the flow path open by over-displacing the perforations greatly reduced the time required between jobs, and that repeated jobs would eventually fill and seal channels.

The confirmation with temperature, noise (Figure 11), and bond logs of no flow behind pipe and zonal isolation between the producing sand and shallower zones completed the well control process. The overall learnings are that even apparently minor well control incidents can result in expensive and dangerous uncontrolled flows when handled ineffectively and that conversely, even serious mistakes can be corrected with careful planning, execution, and monitoring. A summary of the critical issues and turning points in this experience (Figure 12) is used as the conclusion of the training module.

The prototype module has been used four times with rig site personnel as part of pre-well training for drilling HTHP wells in the same area where the incident occurred and once with senior petroleum engineering students in well control lab class at LSU. Typically, it requires 2-3 hours to use in this manner for either audience. Working through the problem with rig site personnel and asking what they would have done at each step showed how seemingly reasonable actions can cause big mistakes and how more rigorous problem solving can correct them. It has helped to show that prevention, detection, and conventional control of kicks are actions that rig personnel can control themselves. When performed correctly, these actions can preclude the need to select, design, and perform the much more difficult tasks involved in controlling an underground blowout. It also provided a dramatic example of how important integration of engineering and operations is for dealing with difficult problems. As such, it encouraged continued openness to discussing problems as a key to establishing the quality of communications necessary for effective teamwork. That effective teamwork allowed resources away from the rig to participate in key decisions and to help analyze and predict the potential consequences of the control actions taken. Those predictions were then used onsite to help determine whether the control process was being conducted successfully and to begin developing contingencies in the event it was not. The effectiveness of this training and the resulting diligence, planning, and cooperation are evident in the success and the reduced frequency and severity of well control operations in the wells drilled following this training.

SUMMARY AND CONCLUSIONS

1. Case histories can be used as "minds-on" practice sessions for learning non-routine well control concepts and methods with a sense of reality that cannot be achieved with simulators or hypothetical examples alone.

2. The prototype module has been used to develop rig site personnel's appreciation for both the importance of their actions to prevent, detect, and control kicks, and for the need to coordinate plans with engineering resources remote from the rig to analyze and predict the consequences of the control actions being taken. This analysis is necessary for both monitoring implementation of the current plan and developing appropriate contingency plans.

3. The case histories provide strong reinforcement for action toward the prevention, detection, and successful control of kicks as the best approaches to preventing and therefore controlling underground blowouts.

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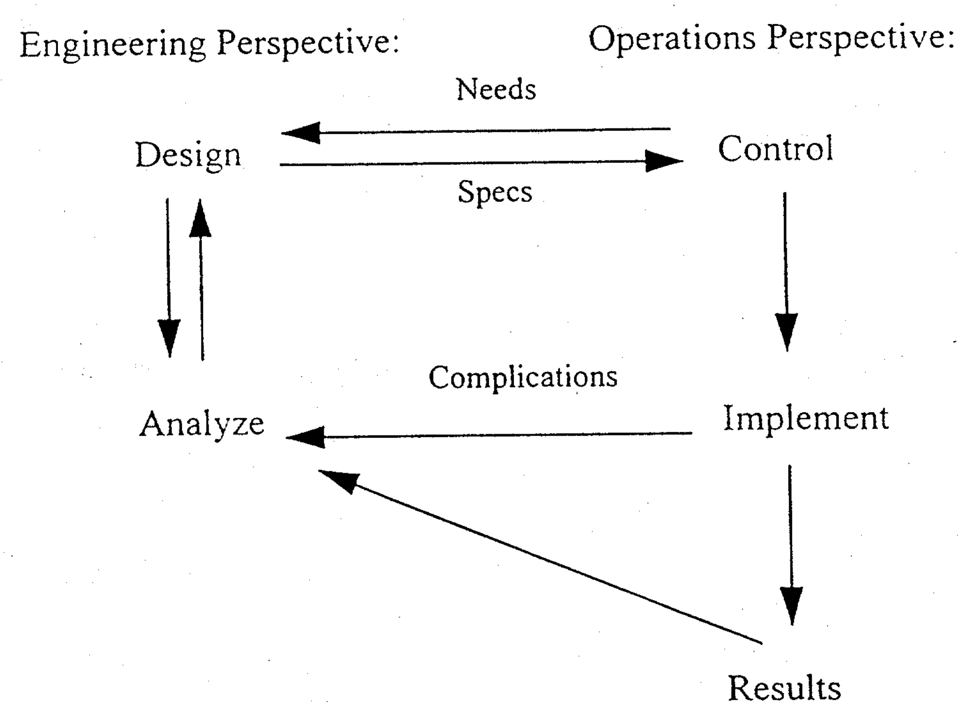
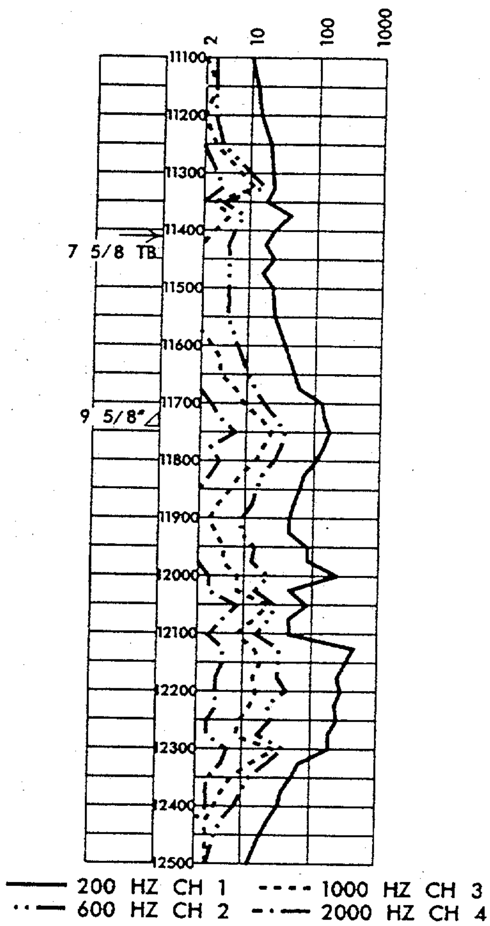


Figure 1 - Model for Integrating Engineering and Operations

Noise Log

Before



Temperature Log

Before

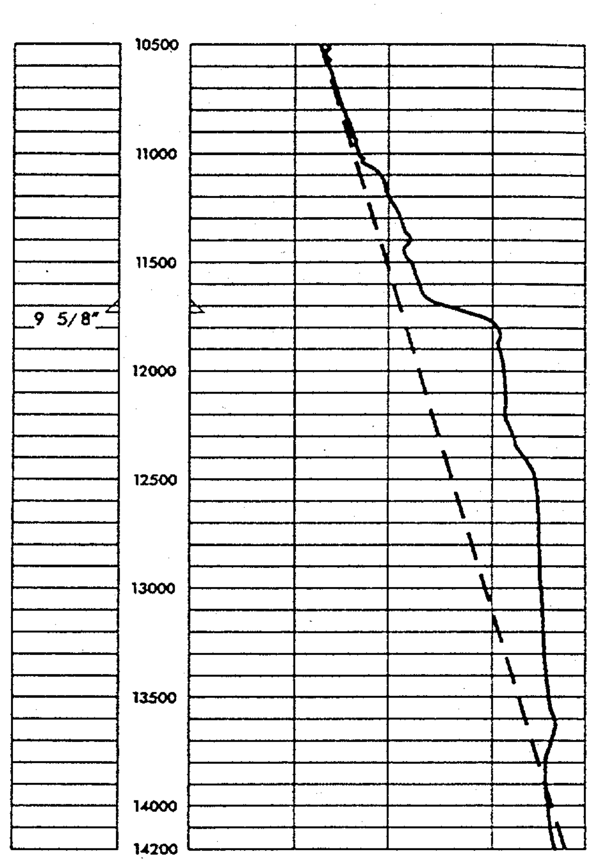


Figure 2 - Noise and Temperature Logs Showing Flow Behind Pipe in Underground Flow Offshore Texas

Offshore Texas Case History

Well Plan

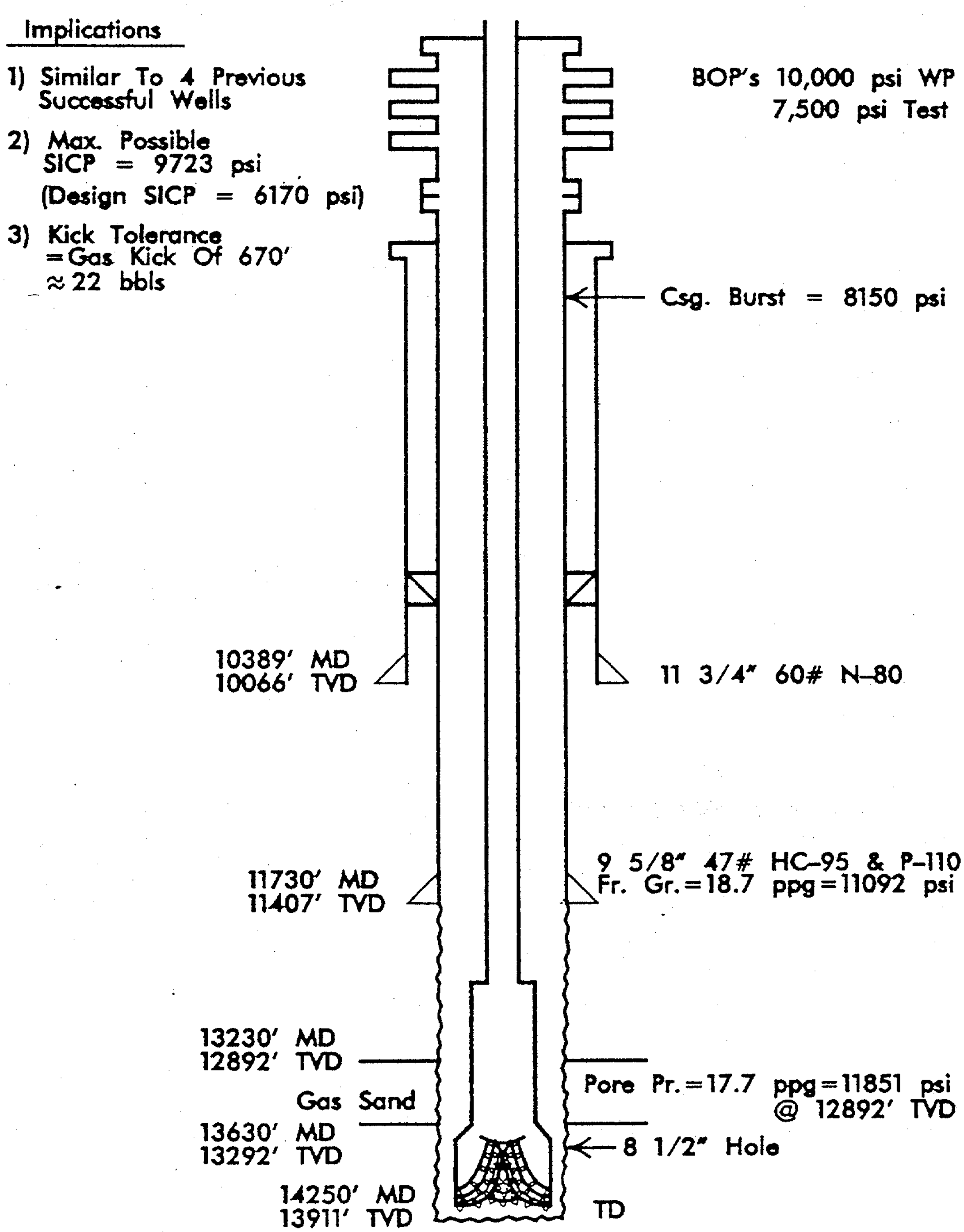


Figure 3 - Wellbore Diagram for Underground Flow Offshore Texas Showing Well Plan

Offshore Texas Case History

After Cementing

Operations

1) Pick Up 3 Stands
2) Reverse Out W/ "Nearly Full Returns"
3) Open Hydril, Well Flowing
4) SIDPP = 150 psi
   SICP = 150 psi

Cause Of Kick

Flow After Cementing
Or
Loss Of Hydrostatic
(If > 140')
Or
Both

Implication

Well Probably Static After Shut–In

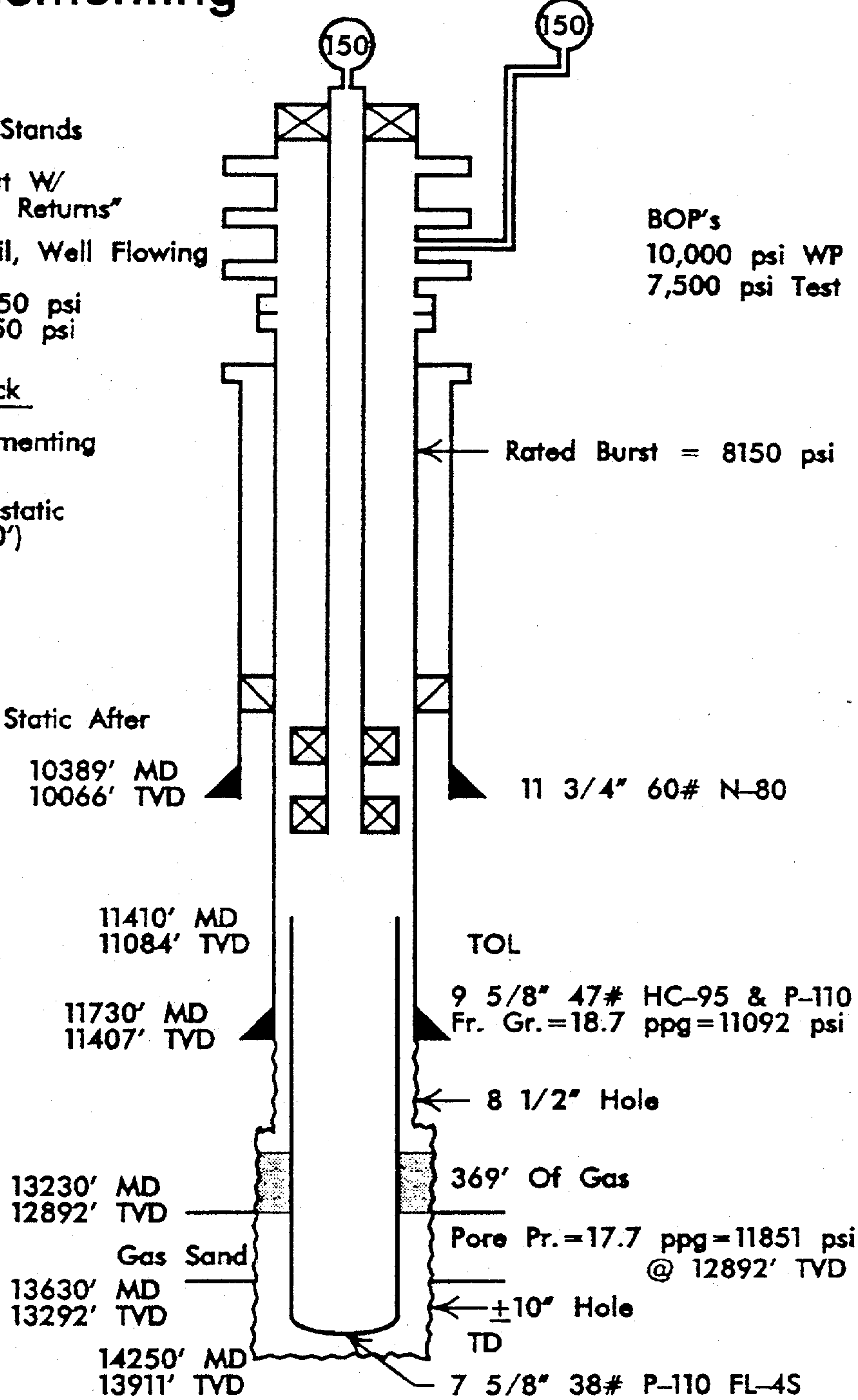


Figure 4 - Wellbore Diagram for Underground Flow Offshore Texas Showing Production Liner as Run and Cemented

Offshore Texas Case History

Attempt To "Control"–A Turning Point

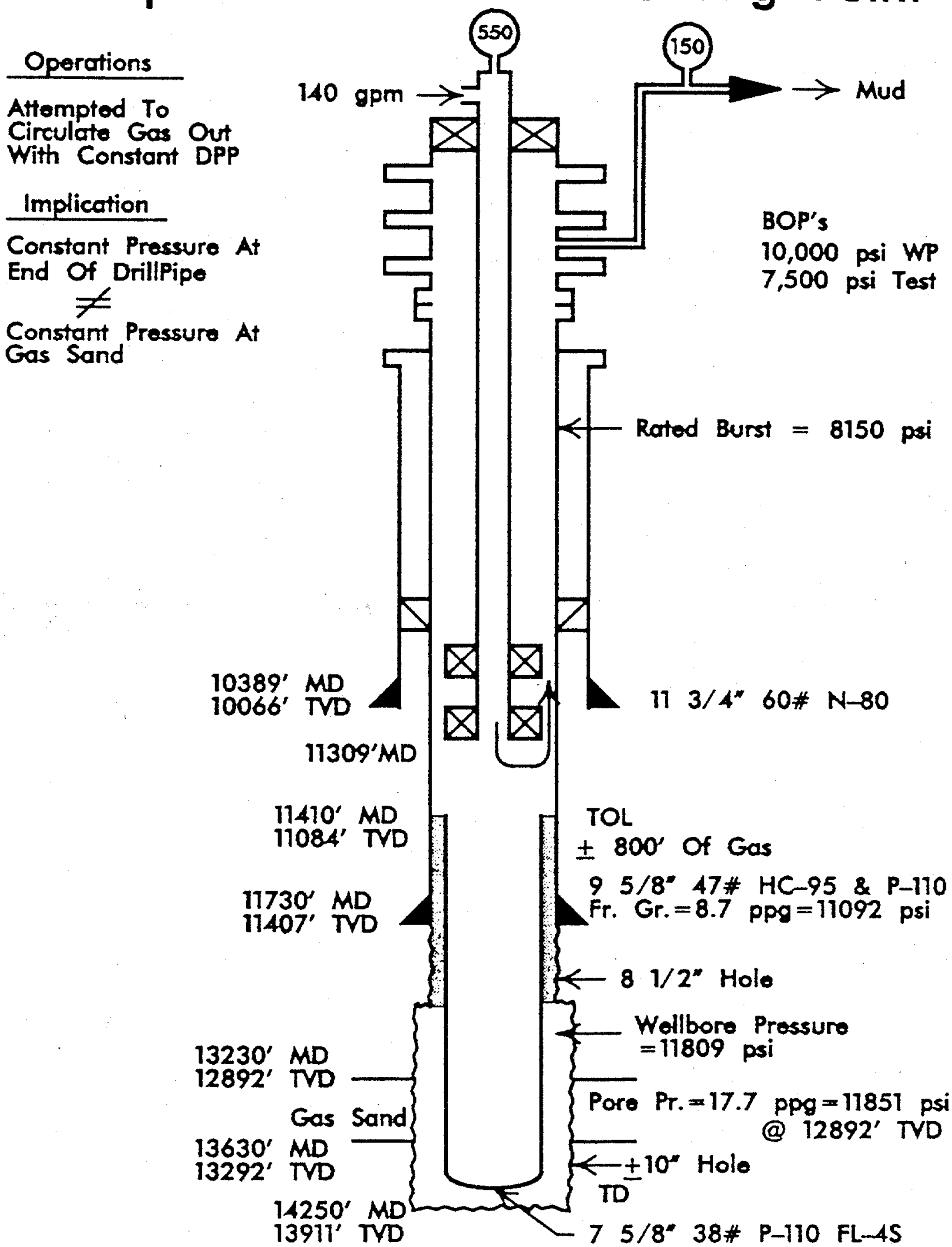


Figure 5 - Wellbore Diagram for Underground Flow Offshore Texas Showing Attempt to Control Kick with Constant Drill Pipe Pressure

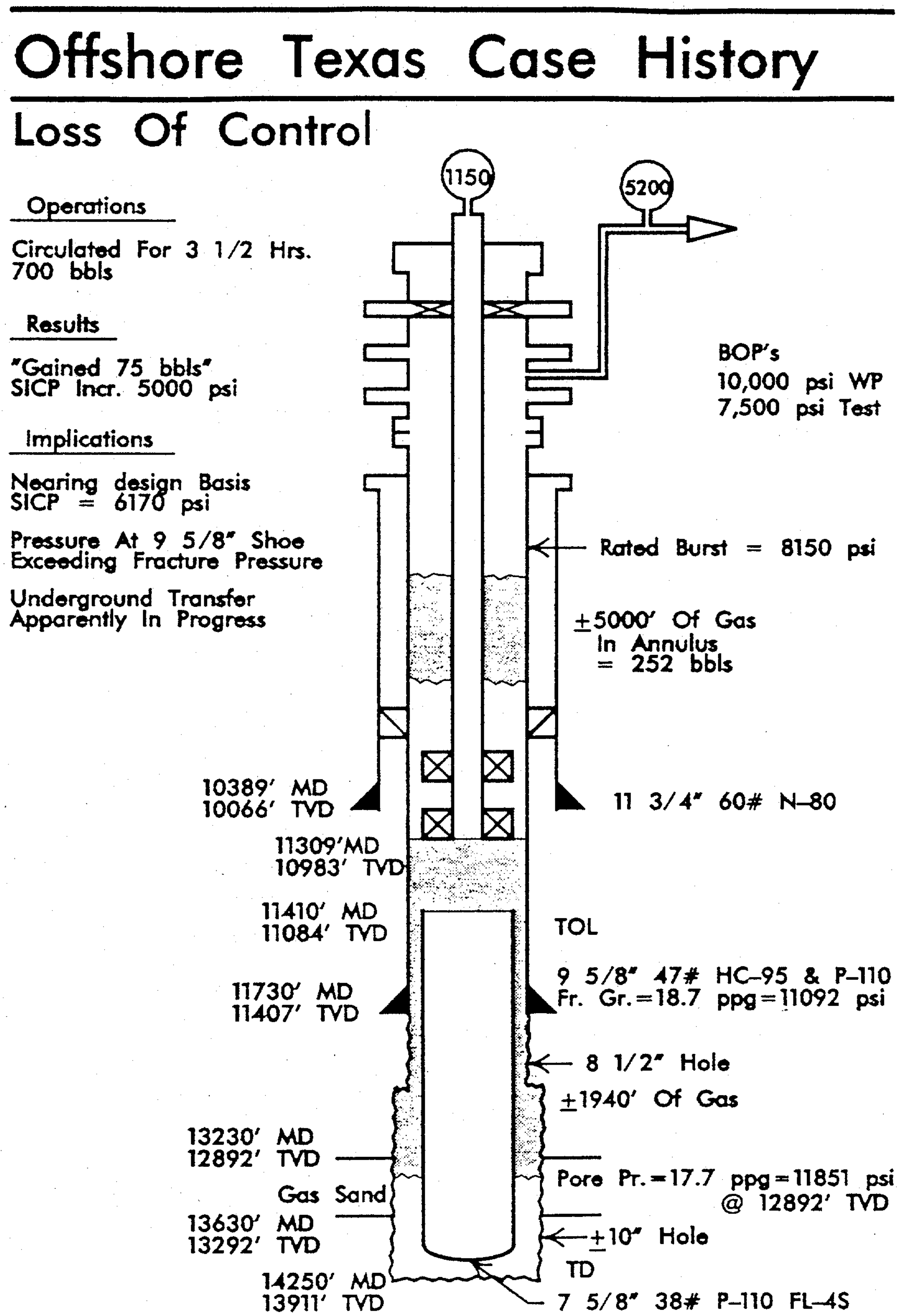


Figure 6 - Wellbore Diagram for Underground Flow Offshore Texas Showing Excessive Casing Pressure after Circulation with Constant Drill Pipe Pressure

Offshore Texas Case History

Attempted Recovery

Operations

1) Ineffective Attempt To Lubricate Annulus (6 bbls Pumped)
2) Ineffective Attempt To "Lubricate" Down Drillpipe (26 bbls Pumped)
3) Attempt To "Test Shoe" By Pumping 8 bbls In Annulus; Drillpipe & Casing Pressure Increase As If Closed System
   Maximum
   SIDPP = 2000 psi
   SICP = 6200 psi
4) Bleed Gas To "Flow" Well And Then Attempt To Pump In Annulus, Pressure Broke Back On 2nd Try
5) Pump 588 bbls Mud In Annulus

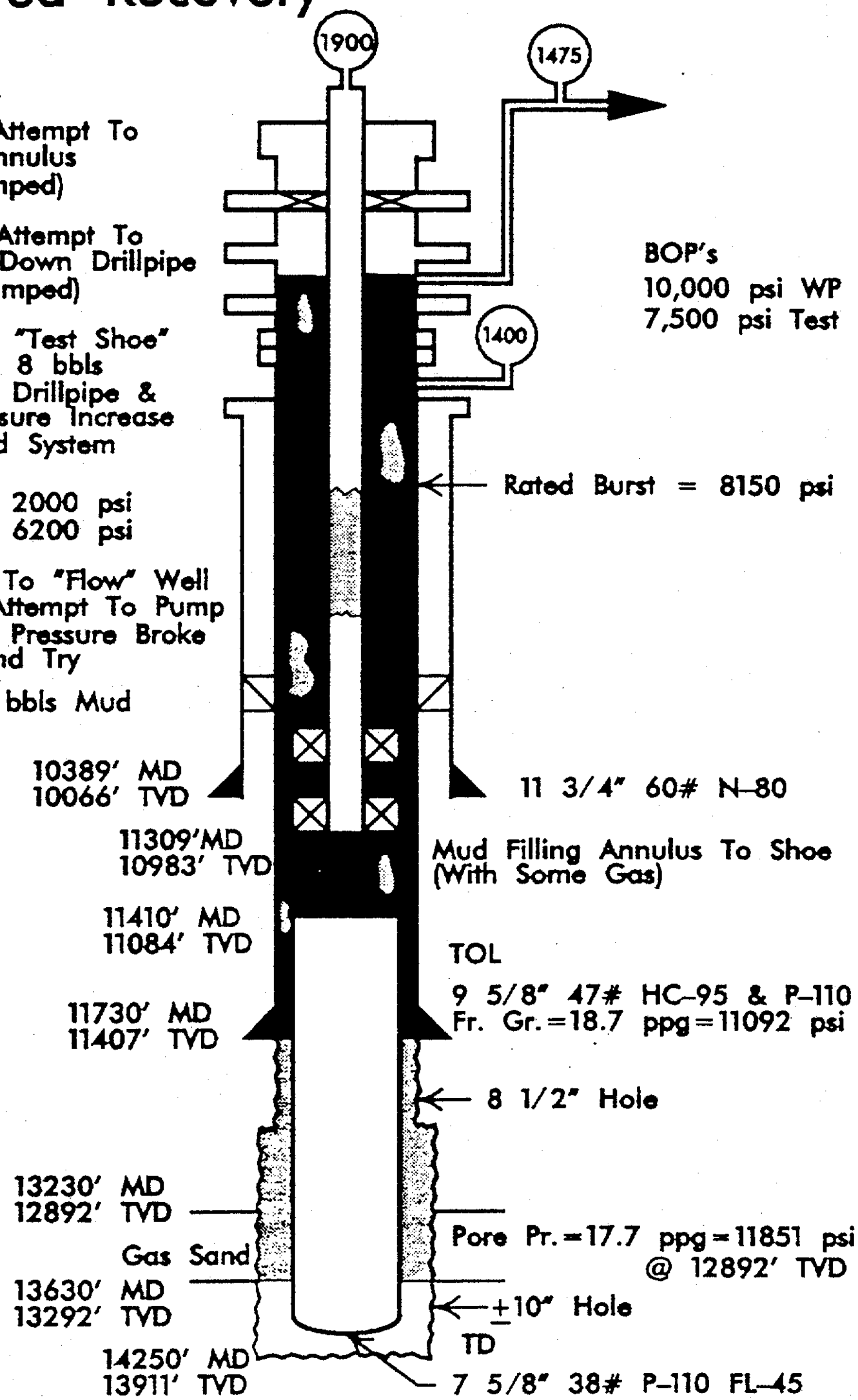


Figure 7 - Wellbore Diagram for Underground Flow Offshore Texas Showing Results of Bullheading Mud Down the Annulus

Offshore Texas Case History

Attempted Recovery

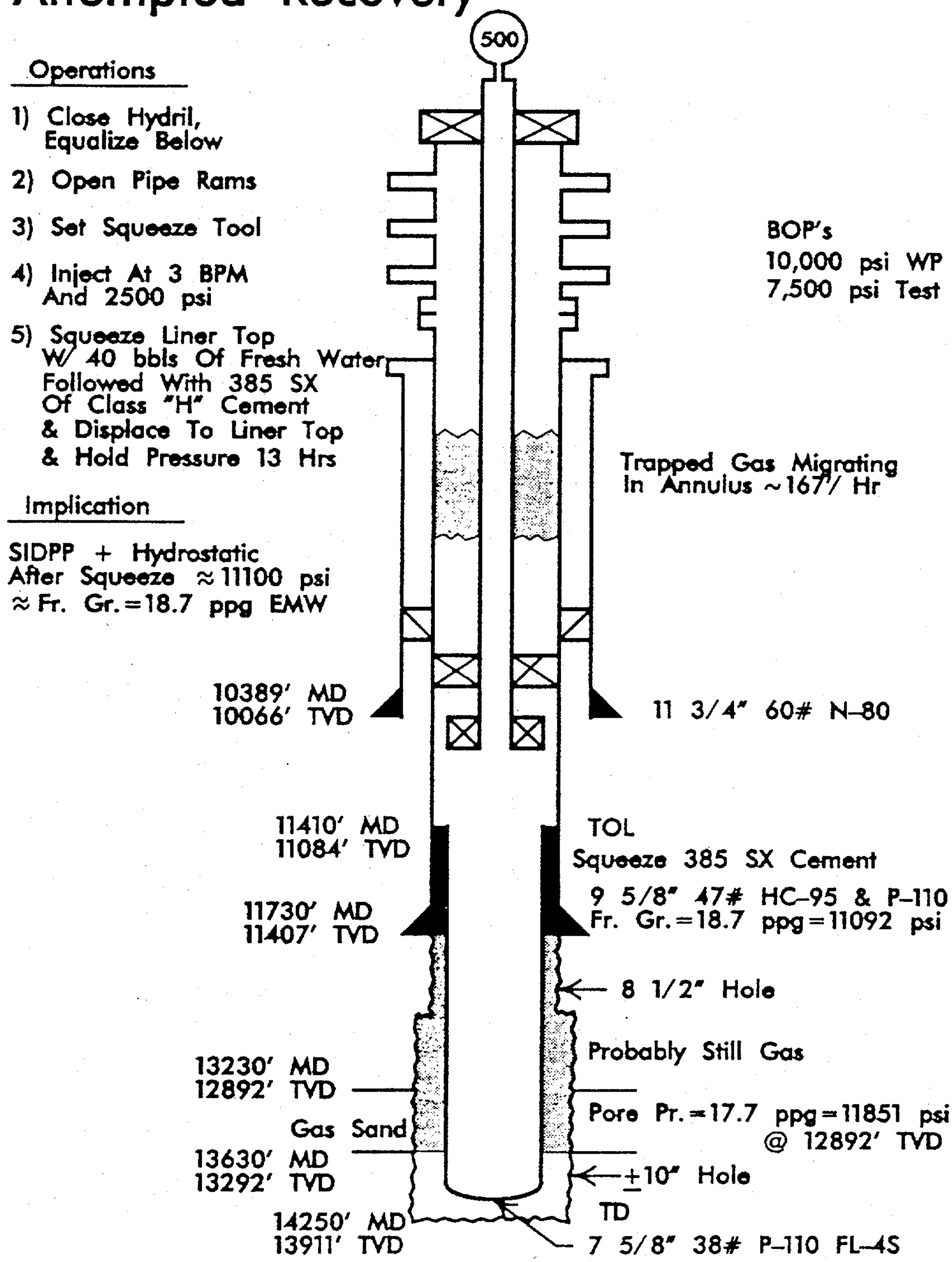


Figure 8 - Wellbore Diagram for Underground Flow Offshore Texas Showing Results of Squeezing Liner Top with Cement

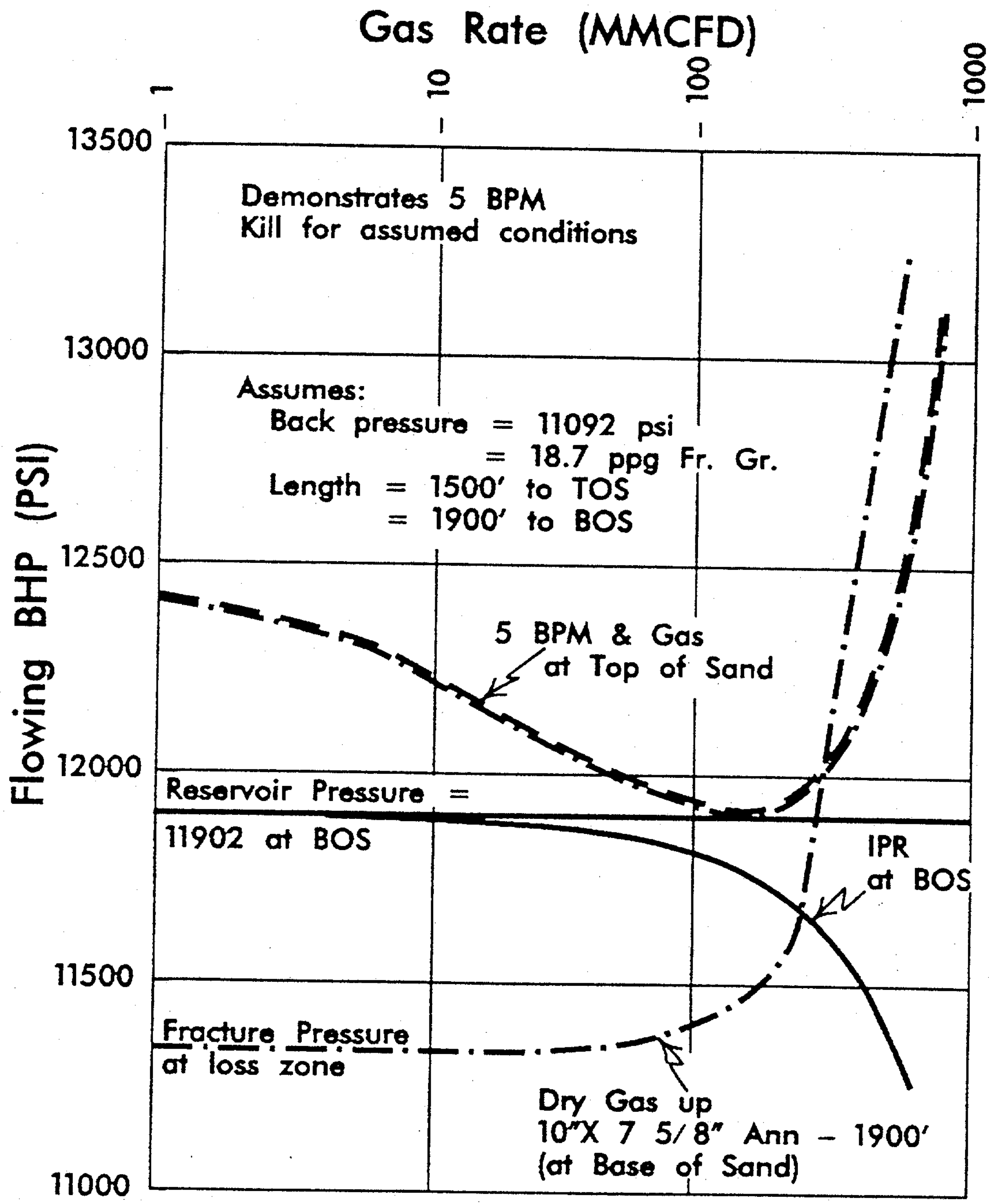


Figure 9 - Prediction of Bottom Hole Pressures and Gas Flow Rates in Annulus for Underground Flow Offshore Texas

Offshore Texas Case History

Recovery

Operations

1) Perforate And Squeeze 400 Sx Class H Cement At Top Of Sand
2) Cleanout & Run CBL
3) Perforate At Top Of Prior Squeeze And Squeeze 400 SX Class H Cement
4) Cleanout & Run CBL
5) Reperforate And Squeeze Interval W/ 400 SX Class H Cement & Overdisplace
6) Resqueeze W/ 400 SX & Overdisplace
7) Resqueeze W/ 400 SX & Leave Cement In 7 5/8"
8) Cleanout
9) Run CBL, Temp & Noise Logs

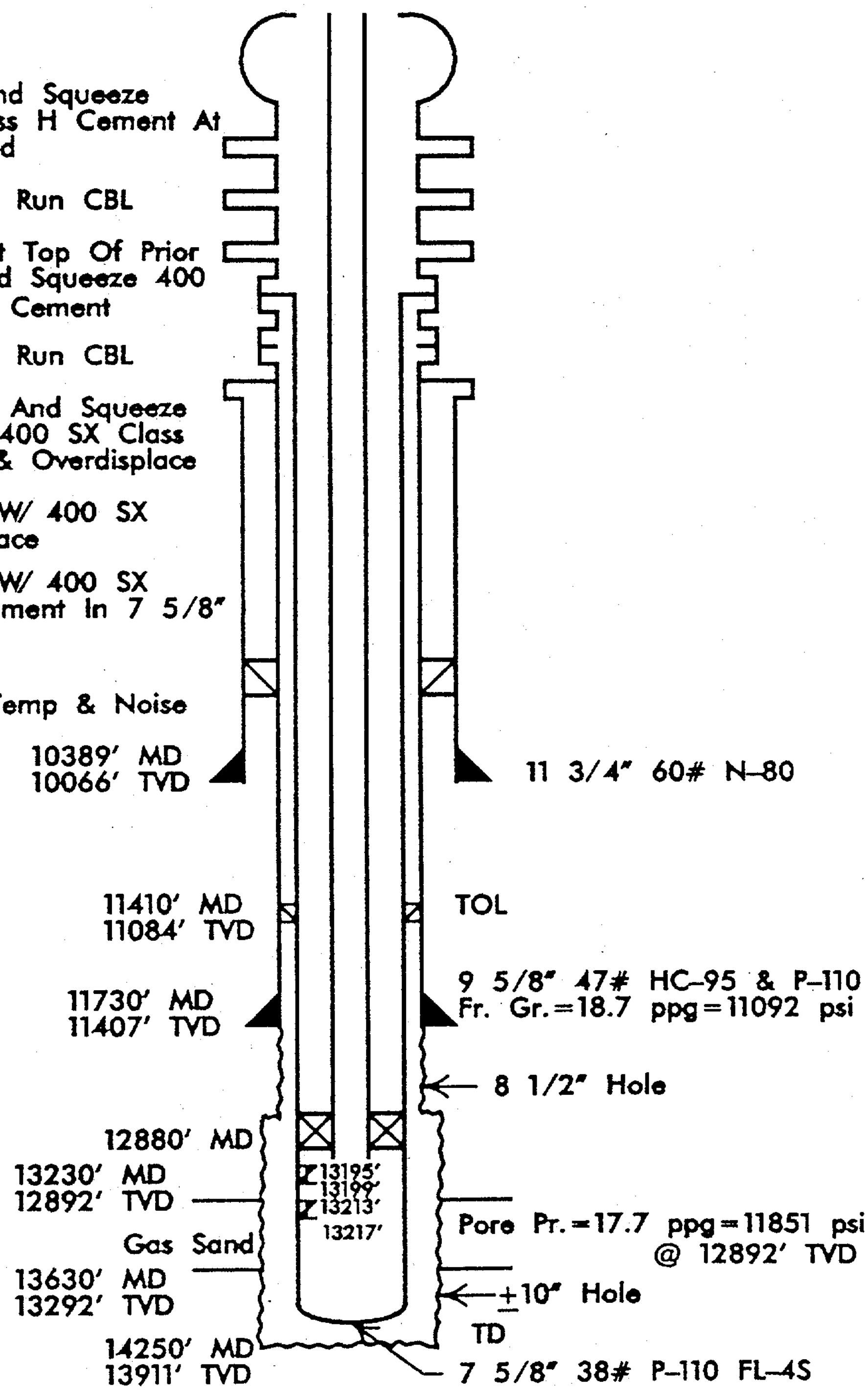


Figure 10 - Wellbore Diagram for Underground Flow Offshore Texas Showing Cementing Operations at the Top of the Producing Sand

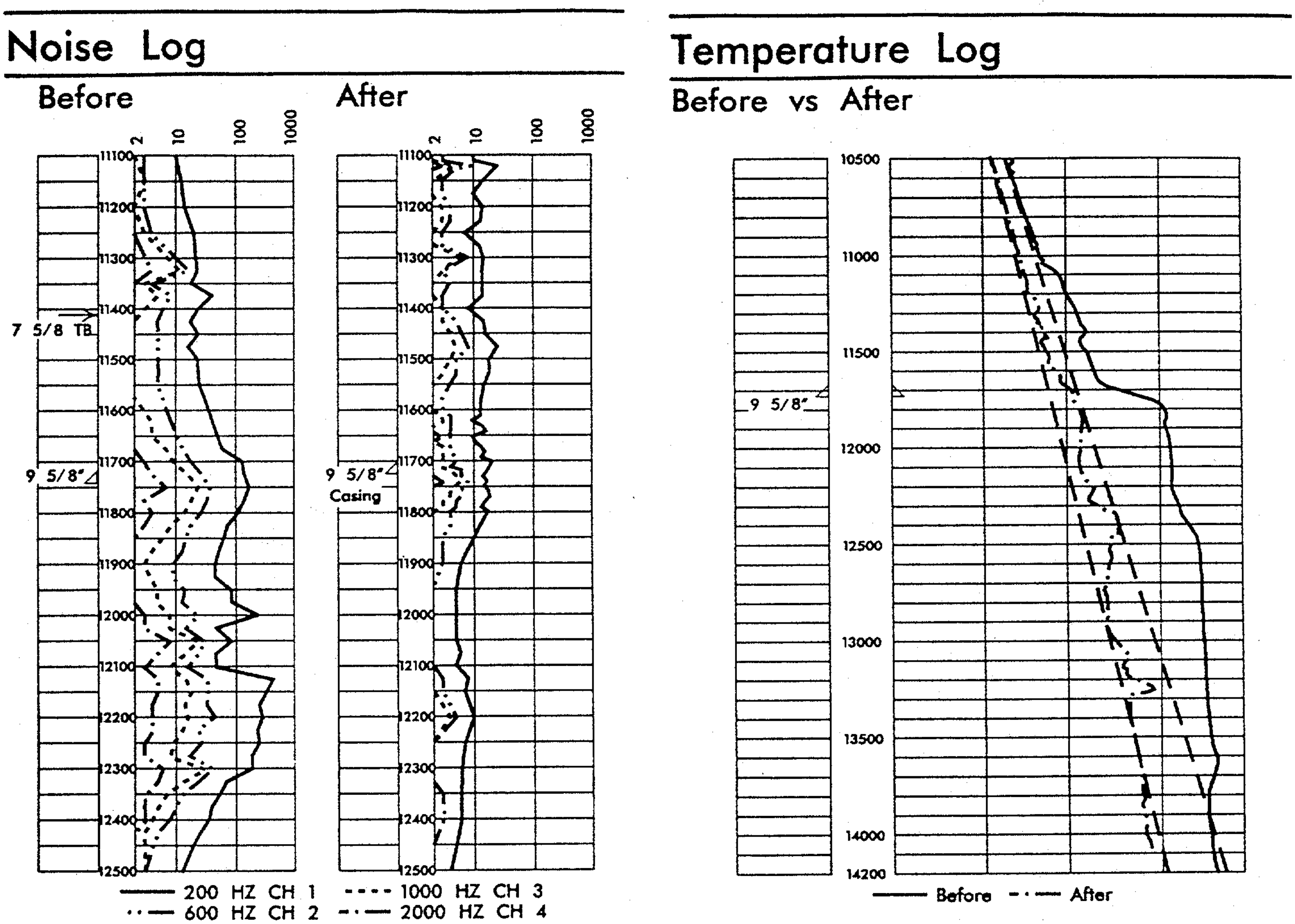


Figure 11 - Noise and Temperature Logs Showing Elimination of Flow Behind Pipe in Underground Flow Offshore Texas

Offshore Texas Case History

Conclusions

Phase	Critical Issue / Turning Point
Planning & Preparation	Risk Of Lost Circ. W/ Smaller Clearances
Avoidance	? Running & Displacement Monitoring
Detection	?
Reaction	<Good–Shut In>
Control	Neither Followed Plan (Squeeze Tool) Nor Properly Implemented Plan Used ("Driller's Method")
Orig	
Loss Of Control	Not Identified
Recovery	None – Only Isolated
Confirmation	None
Second	
Loss Of Control	Inferred By Kicks, Confirmed With Logs
2nd Recovery	Planned, Evaluated After Each Step
Confirmation	Thorough, Compared To Baseline Logs

Figure 12 - Summary of Critical Issues and Decisions in Case History of Underground Flow Offshore Texas

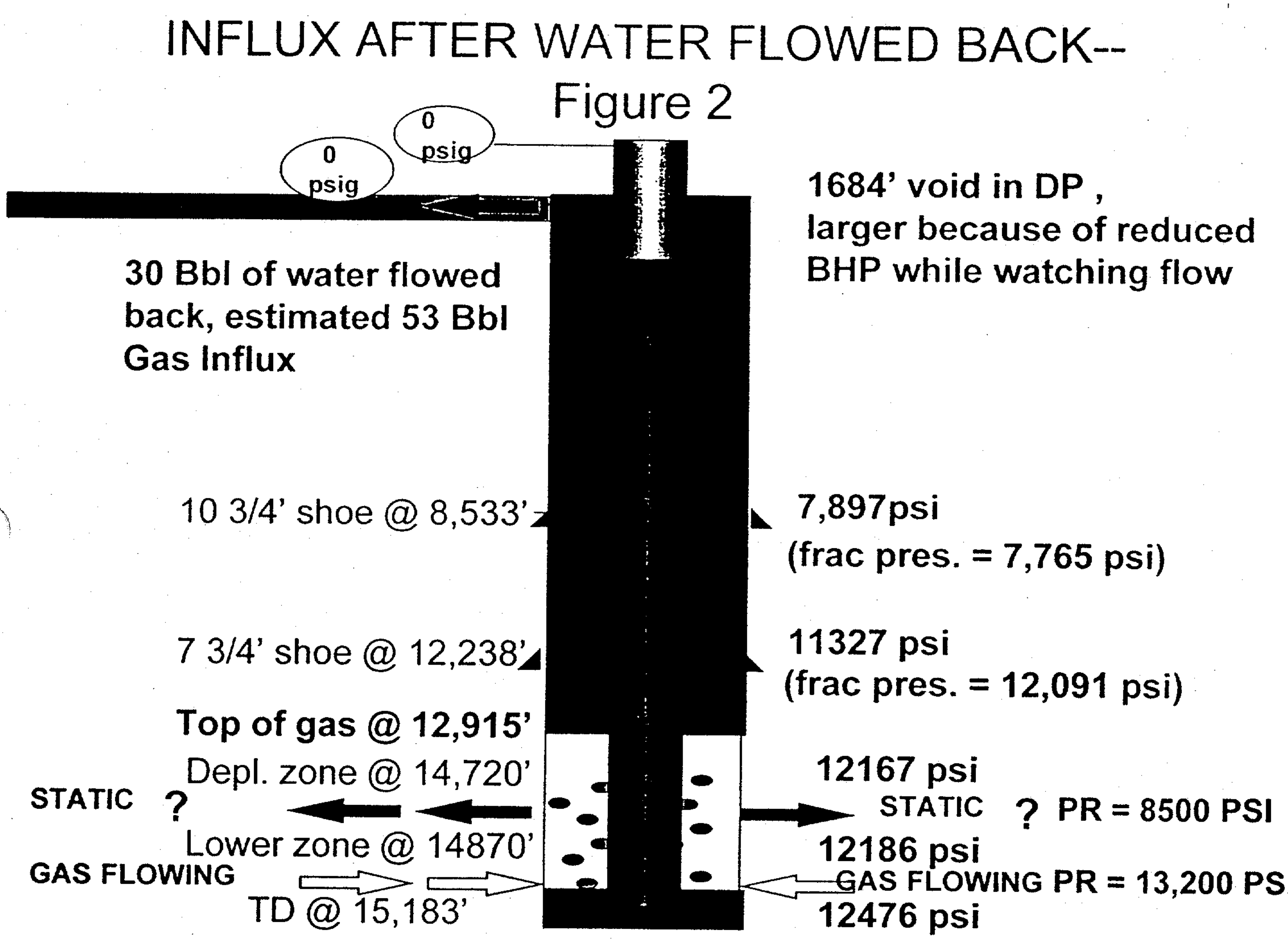


Figure 13 - Wellbore Diagram Showing Conditions Preceding Shut In of the Kick Leading to the "South Texas Blowout"

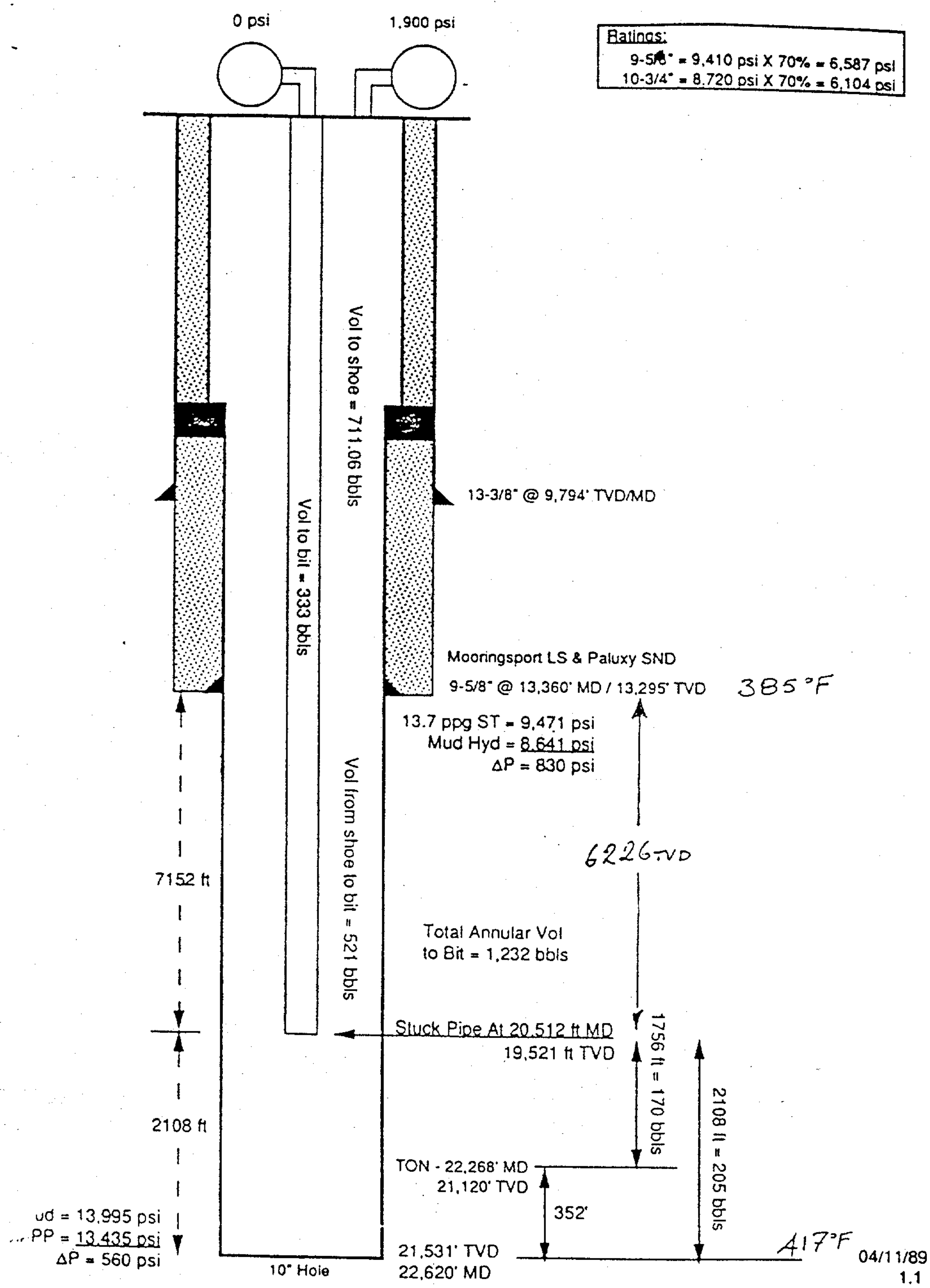


Figure 14 - Wellbore Diagram Showing Conditions when Shut In on Kick Causing a "Deep Underground Flow

AUTOMATED DETECTION OF UNDERGROUND BLOWOUTS

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Ben Bienvenu and Adam T. Bourgoyne, Jr., LSU

Abstract

Underground blowouts, the uncontrolled flow of formation fluids from one formation zone to another, are extremely difficult well control situations. They are not only wasteful of natural resources, but are dangerous and destructive. When shallow, underground blowouts can lead to cratering and a resultant surface blowout, endangering the lives of the rig crew and potentially causing total destruction of the rig equipment (Rocha, 1993). It is imperative that underground blowouts be diagnosed as soon as possible; yet, early signs of an underground blowout are often not identified or at times denied since the usual manifestations of a blowout are not present (Grace, 1994).

A study has been completed demonstrating that detection of underground blowouts can be enhanced through the use of specialized automated or computer assisted well control systems. Oftentimes during well control operations, detection of an underground blowout is inhibited due to erratic surface pressure readings, a result of inappropriate choke manipulations or control. However, proper pressure maintenance during well control operations has been demonstrated achievable via software like that developed at Louisiana State University (LSU). The LSU software, designed for a deep ocean environment well control system, has been converted to operate on a standard PC platform and enhanced to include expert systems type logic for detection of underground flow or blowouts. The enhanced system, designed to accommodate both surface and subsurface BOP stack configurations, was developed for implementation following kick recognition and wellbore shut-in. Testing of the newly developed system was completed utilizing surface and subsurface configured wellbores at the LSU Petroleum Engineering Research and Technology Transfer Laboratory.

Introduction

Tremendous financial losses can be incurred as a consequence of an underground blowout, the uncontrolled flow of formation fluids from one formation to another, even though visible signs of damage are seldom seen at the surface. In fact, underground blowouts may go undetected for long periods of time. It has been reported that the recovery costs associated with Mobil's West Ventura N-91 underground blowout in 1984-1985 were approximately $124,000,000 (USD) while Saga Petroleum's North Sea Well #2/4 14 underground blowout in 1989 cost approximately $285,000,000 (USD) (Mobil, 1992). Even though these costs are extreme, it should be recognized that other factors could drive the blowout recovery costs even higher. For Example, if casing is set shallow and there is an extended length of open hole, the possibility of cratering exits. Should the well crater, not only do you lose the reserves, but now a surface blowout exists with possible loss of life, total loss of the rig equipment, and extensive environmental damage.

When drilling, an underground blowout is typically preceded by lost returns. If lost circulation is encountered at the bit, the fluid level in the wellbore will fall, dropping the hydrostatic pressure, allowing an upper zone to flow. However, if returns are lost to an upper zone, the reverse is true. In either case, there will be upward migration of kicking fluids within the annulus and associated erratic shut-in pressures. However, it is thought that most underground blowouts occur once a kick has been taken and the blowout preventers have been closed.

In a post kick scenario, the uncontrolled flow of formation fluids from one formation to another is initiated by the fracture of a formation, generally located near or at the casing seat. Once the fracture occurs and the hydrostatic pressure drops due to fluid loss, crossflow is initiated. The zone flowing will typically be a deeper zone having sufficient permeability to allow the higher pressured in-situ fluids to flow once the hydrostatic pressure has been lowered. Dependent on severity, it may take several hours or even days before it is recognized that an underground blowout is in progress. Early detection or recognition of indicators, such as partial or lost returns, that may alert the drilling personnel that conditions are favorable for initiation of an underground blowout is critical. To relate the difficulty in recognition of the problem, one major operator indicated that their company's experience showed that up to 60% of all executed well kills had lost circulation problems and most were never detected. In fact, temperature, noise and radioactive tracer surveys are often run when a suspected underground blowout is in progress. These surveys are not run just to locate flowing and thief zones, but to verify whether a underground blowout is in progress or not.

This project was completed to demonstrate that real time automated detection of underground blowouts during well kill operations is practical with today's technology. This was accomplished through the integration of enhanced underground blowout analysis software developed for use as an integral part of a computer assisted or automated well control operations package. LSU Well #1 was reworked such that lost circulation could be emulated, permitting the enhanced computer assisted well control system to be tested. This project was designed to be an extension of the work completed earlier, "A computer Assisted Well Control Safety System for Deep Ocean Well Control," (Kelly, 1989). As part of this work, the earlier developed software was converted to current PC technology, utilizing National Instrument's LabVIEW® software and data acquisition system. The software was then altered to include expert system type analysis software to accommodate detection of underground blowouts.

Once an in-progress underground blowout is confirmed, conventional surface blowout well control recovery techniques will not suffice for regaining control of the well. There are several remedial well control techniques or procedures that can be implemented (Barnhill, 1979), but evaluation and selection of an appropriate procedure to remedy an underground blowout is not within the scope of this project.

Manifestations of Underground Blowouts

It is imperative that underground blowouts be diagnosed as soon as is possible. Additionally, it is as important that the direction of flow be determined since this will affect the type remedial action to be implemented. Early detection will possibly minimize the magnitude of the downhole problem and the potential for getting differentially stuck. Oftentimes, underground blowouts are more challenging to solve than are surface problems due to unknowns. It is difficult to get the volume and density of the transient influx fluids as well as which tubulars are involved. Typically, these unknowns are resolved with temperature (most likely differential temperature), noise and radioactive tracer surveys.

Underground blowouts manifest themselves in varying ways. When drilling, underground blowouts are generally initiated by lost circulation at the bit. The lost circulation can be a result of penetrating a subnormally pressured zone, depleted zone, highly fractured zone, unsealed fault plane, etc. Messenger (1981) defined loss circulation zones into horizontal and vertical loss zones with horizontal occurring at depths of 2500 to 4000 feet. He categorizes horizontal loss zones as occurring in porous sands and gravel, natural fractures, induced fractures and cavernous zones while vertical loss zones occur into natural fractures and induced fractures. Irrespective of loss zone type and once the fluid level falls sufficiently, fluid flow from an upper zone can and will be initiated (**Figure 1a**) given that an upper zone has porosity, permeability and charged with an in-situ fluid capable of movement. When loss circulation is recognized and crossflow or an underground blowout is suspected, the well is then shut-in and remedial actions planned.

This project demonstrates the practicality of underground blowout detection once normal well kill operations have been initiated. In other words, up to the point of bringing the pump on line for a well kill operation, no obvious manifestations of an underground blowout are present. Given the boundaries of this work, initiation of an underground blowout is the result of insufficient kick tolerance (Wessel, 1991), resulting in formation fracture and fluid flow from a higher pressured formation downhole. **Figures 1b, 1c and 1d** are scenarios common to post-kick underground blowouts. Formation fracture at the shoe is the more common scenario given too high a shut-in or circulating casing pressure. However, formation fracture due to leaky cement jobs and casing failure are all too often the initiator of an underground blowout.

Early detection of underground blowouts that flow from deep formations to shallower formations is of considerable concern due to the abnormal charging of the upper zone(s). Under certain conditions, a surface blowout and possible cratering can ensue due to formation fluids channeling to the surface. Cratering (Rocha, 1993) can occur via four mechanisms:

- Borehole erosion - erosion of shallow formations around the surface casing due to formation fluid seepage or flow

- Caving - the collapse or slumping of the shallow formations due to sediment (sand or silt) production as a consequence of fluid flow to the surface
- Formation liquefaction or fluidization - fluid flow, typically gas, through shallow cohesionless or poorly cemented sediments
- Piping - the flow of formation fluids through channels, fault planes, etc., to the surface. This is especially seen in deep water.

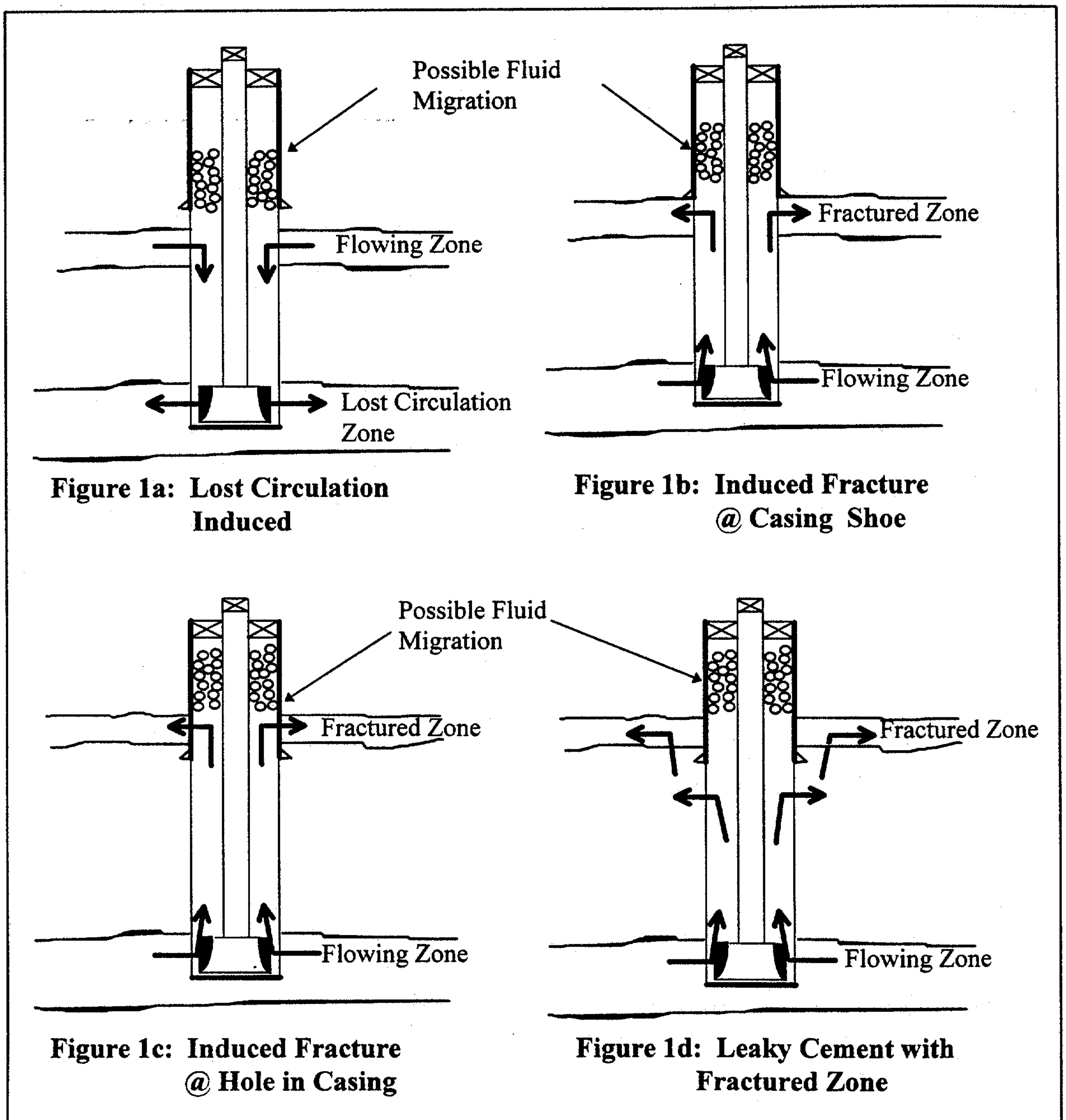

Figure 1: Underground Blowout Scenarios

Examples of surface blowouts as a consequence of underground blowouts are documented by Grace (1994).

Recognition of Underground Blowouts

Indicators of underground blowouts are not always consistent. There are not a fixed set of tell-tale signs which absolutely imply that an underground blowout is in progress. In general, an underground blowout is defined by a lack of pressure response on the annulus while pumping or by the lack of pump pressure response. Sometimes the surface pressures are so nominal that one may be lulled into a false sense of security; At times, no physical manifestation is present at all. **Table 1** (Adams, 1986) documents the shut-in surface pressures witnessed during one underground blowout episode. As can be seen, the pressures were very erratic.

Time	SIDDP, psi	SICP, psi
3:15	350	1,100
3:18	475	1,300
3:20	510	1,360
3:22	525	1,380
3:24	475	1,340
3:26	475	1,110
3:28	425	1,090
3:30	350	1,090
3:40	0	1,090
3:50	125	1,250
4:00	140	1,200
5:00	130	1,120

Table 1: Erratic Shut-in Pressures for Sample Underground Blowout

The most prevalent indicators of underground blowouts during shut-in include:

- Initial drill pipe and casing pressure build-up followed by subsequent reductions
- Fluctuating drill pipe and casing pressures, not necessarily together
- Drill pipe pressure may be higher than the casing pressure
- Drill pipe has an excessively low pressure reading, even can go on vacuum
- Lack of communication between drill pipe and casing pressures (Flack, 1994)

If an underground blowout initiates during well kill pumping operations, pit levels will potentially be affected. As fluid is lost to a fractured formation, pit levels decrease even though gas expansion and resulting pit gains were anticipated. This symptom may be subtle, dramatic or not even noticeable for a long period of time. All indicators must be taken into consideration jointly to discern some underground blowouts, a task possibly more easily handled by a computer with proper rule based technology.

One major complication to identification of an underground blowout is the erratic choke manipulation often demonstrated by the choke operator during a well kill operation. This erratic or inappropriate choke manipulation was documented by Kelly (1994). Erratic choke manipulation creates erratic drill pipe and casing pressures, emulating one of the best indictors of an underground blowout. Consequently, it is not difficult to see that detection of an underground blowout during a poorly executed well kill plan is almost impossible because the earmarks of a blowout are masked by what the choke operator thinks is normal pressure fluctuations.

How Can Computers be Utilized in the Detection of Underground Blowouts?

The major obstacle to overcome in detection of underground blowouts during well kill operations is inconsistent pressure control during start-up, followed by the continued inability of most choke operators to maintain proper pressure control. These pressure fluctuations mask subtle signs of lost circulation and/or underground blowouts. In fact, lost circulation is often induced during the start-up phase of the well kill process, especially in deep water where there is considerable choke line friction and little kick tolerance. The computer assisted well control system developed by Kelly (1994) documented that pressures could be maintained as close as ± 20 psi when using computer assisted pump and choke control in lieu of the ± 200 psi routinely seen when experience operators control the choke.

Given better surface and resultant downhole pressure control when using computer assisted pump and choke control, surface pressure and pit level trends can now be tracked more accurately. Therefore, this project was designed to integrate lost circulation and underground blowout expert system analysis type software into the computer assisted well control system previously developed. Pressure or pit level trend anomalies are now searched every second, a schedule not practical for human operators even if pressures could be properly maintained via manual control. Once an anomaly is detected, the computer will alert the operator via a visual or audible alarm.

System Design

The software developed earlier for computer assisted well control has been converted from the Z-Basic platform to a PC based system developed by National Instruments called LabVIEW®. Additionally, a data acquisition and control system developed by National Instruments was installed at LSU's test well facility to interface between the computer control system and the test well. **Figures 2 and 3** are control screens and real time data plots from the newly developed system.

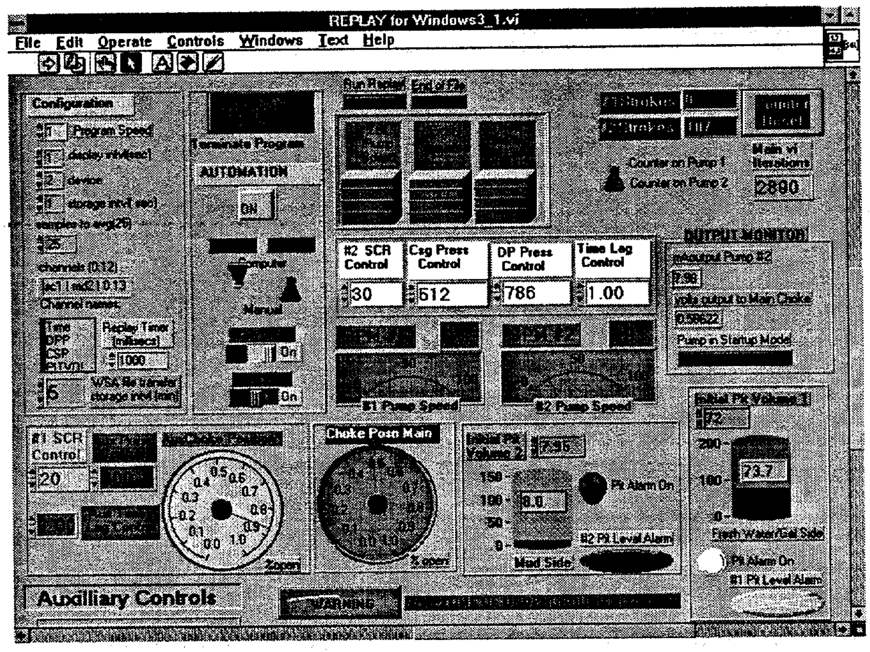

Figure 2: Control Panel for Automated System

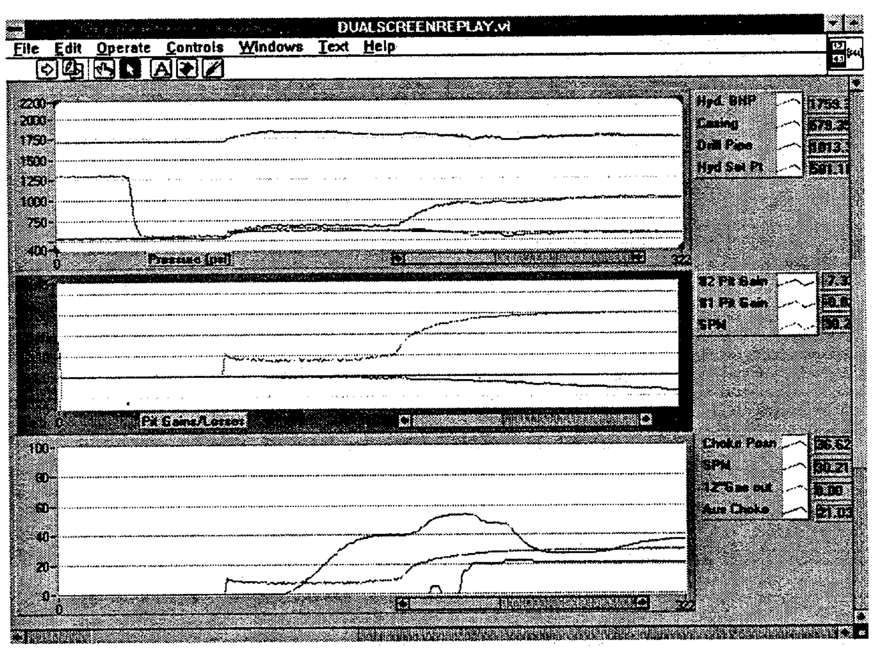

Figure 3: Real Time Output Screen

The system requires data input from the following parameters: drill pipe pressure, casing or choke pressure, kill or monitor line pressure, pump speed, pit level, choke position, choke set point pressure, gas out, and total strokes pumped. Outputs generated by the computerized system include: pump speed control, choke set point control, and digital alarms. **Figure 4** depicts the interaction between the computer and the test well facility.

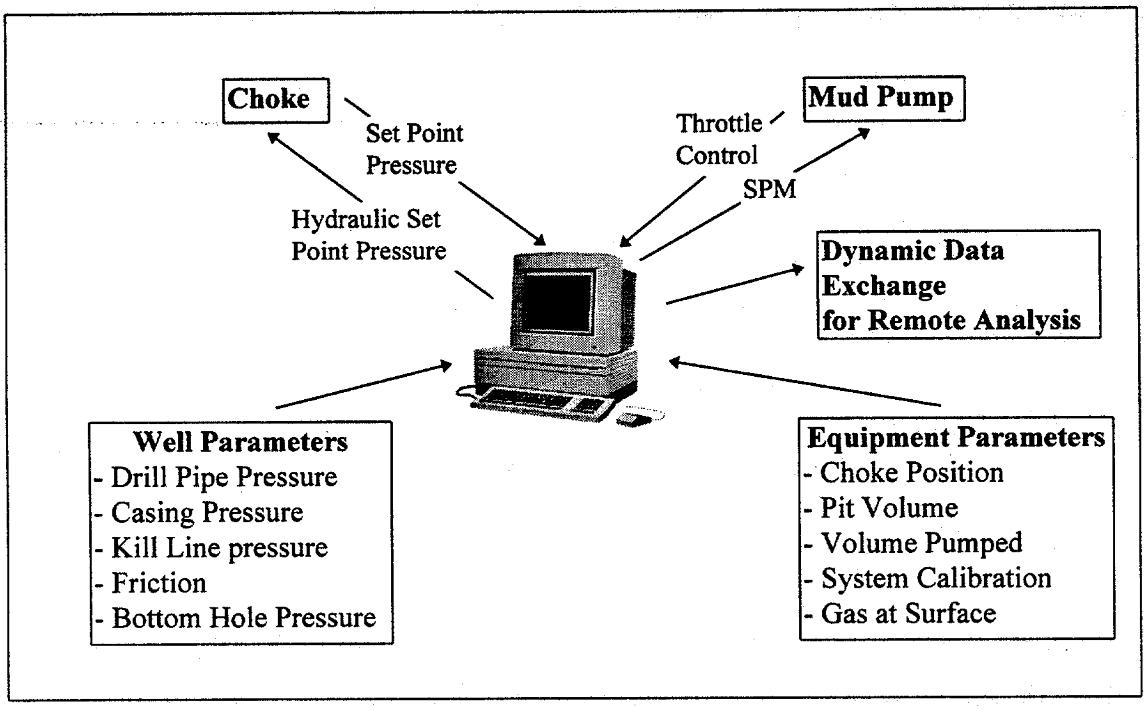

Figure 4: Automated Computer System

Capabilities designed into the system include:

- Continual kick detection monitoring during drilling operations.
- Precise choke line friction pressure control corrections are made on start-up (i.e., the choke or casing pressure is reduced by the appropriate choke line friction associated with current pump speed).
- Once circulating at slow pump speed, the pump speed can be altered (plus or minus) and the system will switch to casing pressure control during the speed control transition. The casing pressure will be held constant, except for making corrections to facilitate choke line frictional changes resulting from circulation rate changes. Once the new pump speed is established and the casing pressure is stable, the system will return to drill pipe pressure control. For surface or jack-up configurations, the frictional changes are assumed equal to zero; therefore, the casing pressure is held constant during pump speed changes.

- A safety factor or over pressure can be implemented upon start-up to minimize the potential for secondary kicks. This factor carries over from casing pressure to drill pipe pressure control and can be altered, plus or minus, any time during the pump-out cycle.
- Digital alarms, both visual an audible, automatically engage the operator to alert the detection of a pressure, choke position , pit level, etc., anomaly.
- Control transfer from automated to manual control with the simple toggling of a switch.
- Expert system software logic to detect anomalies described earlier for lost circulation or underground blowout detection.
- Post analysis display. Can replay all data in real time or accelerated. With this feature, additional analysis and testing of software logic can be inexpensively performed on replay data instead of costly experimentation.
- All parameters are available for dynamic data exchange. Current data files are effortlessly and routinely dumped in protocol formats (ASCII, string files, etc.) so that various file dependent expert systems can be incorporated into the same computer or shared via a network or modem connection to other computers and personnel. This adds considerable value to the program in that many of the algorithms previously developed, (e.g., Well Site Advisor (TRACOR, 1992)) need not be recreated, only incorporated.

Both the control loops for the pump and choke control are closed loop systems. The pump control is porportional in nature whereas, the choke control is porportional plus integral. The system fully checks all parameters every second and makes corrections accordingly.

Test Facility

Figure 5 shows the general layout of LSU's test well facility as used in this study. Included in the system are a triplex Halliburton fluid pump (2.9 gal/stroke), precharge centrifugal pump, two 90 barrel mud tanks, two SWACO (previously Warren Tool Company) drilling choke systems, LSU Well #1, natural gas compressor, degassing and flaring equipment, and a data acquisition system. The choke systems are pressure regulation type chokes (Cain, 1987) such that casing pressure is maintained by setting a back pressure on the floating choke piston, regulating the casing pressure equal to the back pressure set on the backside of the piston. An increase in casing pressure will force the pin open until the casing pressure once again equals the hydraulic set point; a casing pressure decrease acts in reverse, i.e., the choke piston is moved in the closed direction until the pressures equalize. All flow lines and choke manifolds are API 5000 rated. The formation influx or the kick fluids used during testing included both liquid and natural gas.

Figure 6 depicts LSU Well #1 (Bourgoyne, 1994) used for development and validation of the software. The arrows show the normal flow paths for a subsea or subsurface configuration. The true vertical depth of the well is 2787-ft.

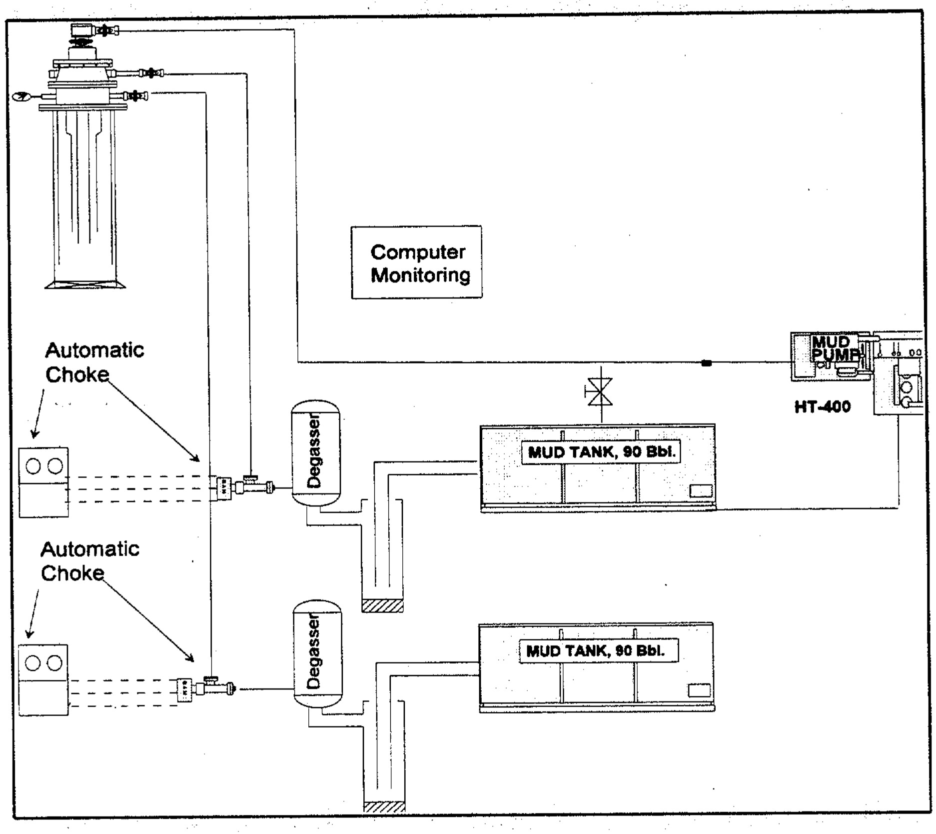

Figure 5: LSU Test Well Facility

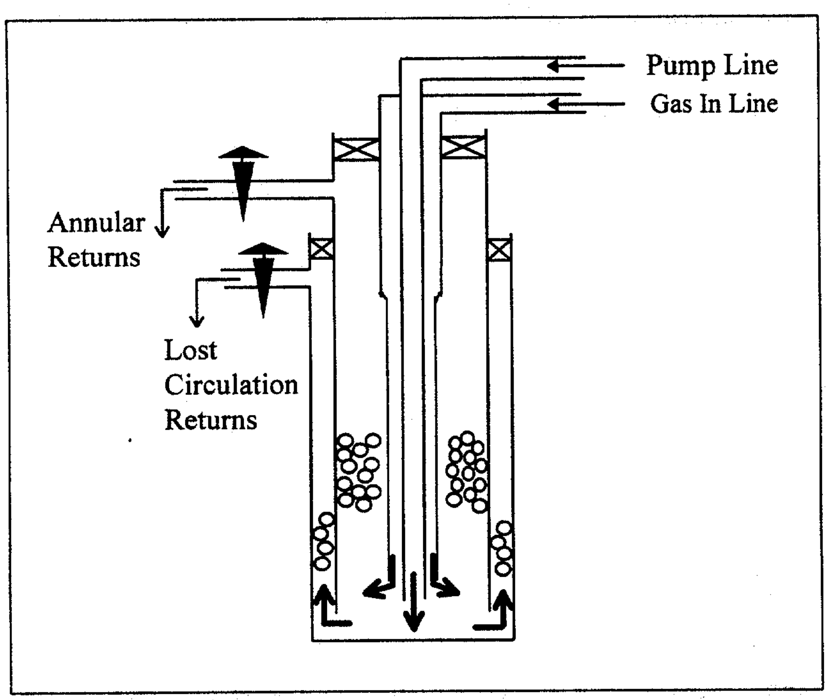

Figure 6: LSU Well #1, Subsea Configured

Test Procedure

The test procedure included the conversion and enhancement of the earlier developed automated well control software. At minimum of 20 simulated salt water kicks were used to validate the software updates prior to initiating gas kick evaluation. A total of 15 natural gas kicks have been taken, modifying the software following each run to enhance or fine tune the process control. Appropriate bells and whistles have added as alarms for underground flow detection.

The procedure for each test included the following:

- Calibration of the system to ensure that input pressure and control pressures were within limits (pit level reading ± 1/2 barrel, pressure readings ± 10 psi, output pressure ± 10 psi, pump rate within 0.5 strokes per minute). The key to detection of underground blowouts is tight control of the automated well kill operation, such that anomalies can be discerned.
- Each time a software change (or group of changes)was made, a simulated salt water kick was taken in the well to validate the effects achieved.
- Once the software had been converted and validated, software changes were made to key in on underground flow signatures as described earlier, detection being identified by both visual and audible alarms.

Results

Consistent choke and pump manipulation by the computer during routine automated startups has been achieved in the software conversion. **Figure 7** (located at the end of the paper) is an actual liquid kick being circulated out of the well. As can be seen, the choke line friction is removed from the shut-in casing pressure on start-up. Note that a 50-psi safety factor was requested and can be seen on the bottom hole pressure plot. Other characteristics of the plot is the parabolic ramp-up of the pump and corresponding drill pipe pressure. Note the smooth transition from casing pressure control to drill pipe pressure control once the pump is up to speed at 30 strokes per minute.

Figure 8 (located at the end of the paper) shows another run with simulated anomalies or lost returns at 243 and 283 strokes. During the run another choke was opened allowing fluid to flow via the outside annulus, simulating lost returns. As can be seen the pressure drops fell throughout the system were significant and sudden. Note should be made that the system immediately recognized the pressure drops, responding with immediate choke corrections and recovered control. These fluid losses were interjected intermittently during the run so that the automated system would be taxed when regaining control.

Finally, **Figure 9** (located at the end of the paper) demonstrated a continual lost circulation problem while circulating out a gas kick. Note the continual pit loss even though gas is expanding as it comes up the wellbore. Also, note the response of the choke in attempting to regain full control of the well. Bottom hole pressure was affected, but not nearly as significantly as would have occurred if left unchecked. Again, the lost circulation alarms were energized, indicated a possible underground blowout as was simulated in this scenario.

The results of all tests demonstrated that given quality pressure control during a well control operation and proper rule based logic, anomalies such as lost circulation or underground blowouts can be detected real time.

Conclusions

- Precise pressure control for well kill operations is necessary if subtle anomalies or trends are to be detected (e.g., lost circulation, etc.).
- The automated well control system developed at LSU is capable of controlling well pressures such that subtle, greater that ± 20 psi, anomalies can be detected.
- Safety will increase as a result of automation because the operators are freed to monitor the overall process rather that controlling routine tiring operations such as pump and choke control.
- Pump start-up casing pressure control, corrected for choke line friction, is critical for deep water operations with minimal kick tolerance.
- Detection of underground blowouts during well kill operations is enhanced with automated expert type systems logic.
- Further development of the LSU system should include dynamic data exchange linked with a system such as Well Site Advisor so that continual analysis of the wellbore, kick fluids, anticipated surface gas, etc., can be completed real time.

Acknowledgment

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**Figure 7 -- Automated Well Control Subsea Startup-
Adding Safety Factor and
Discounting Choke Line Friction**

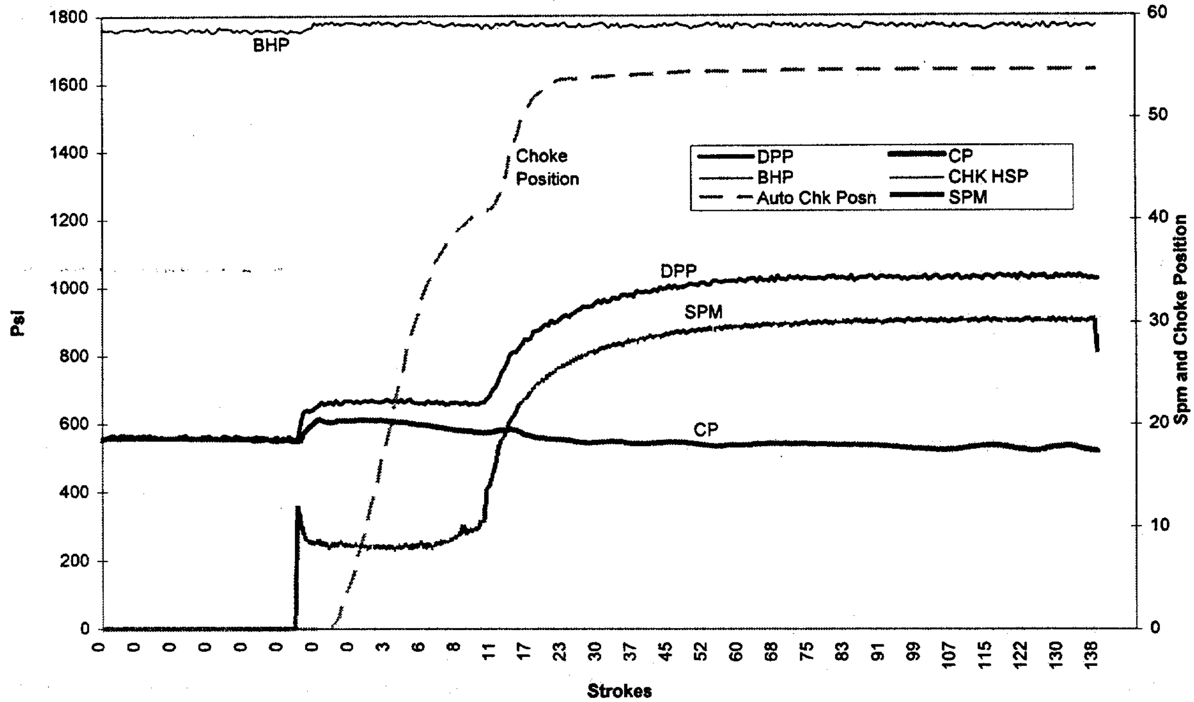


**Figure 8 -- Startup-Saltwater Kick
Displaying Rapid Recovery to System Upsets**

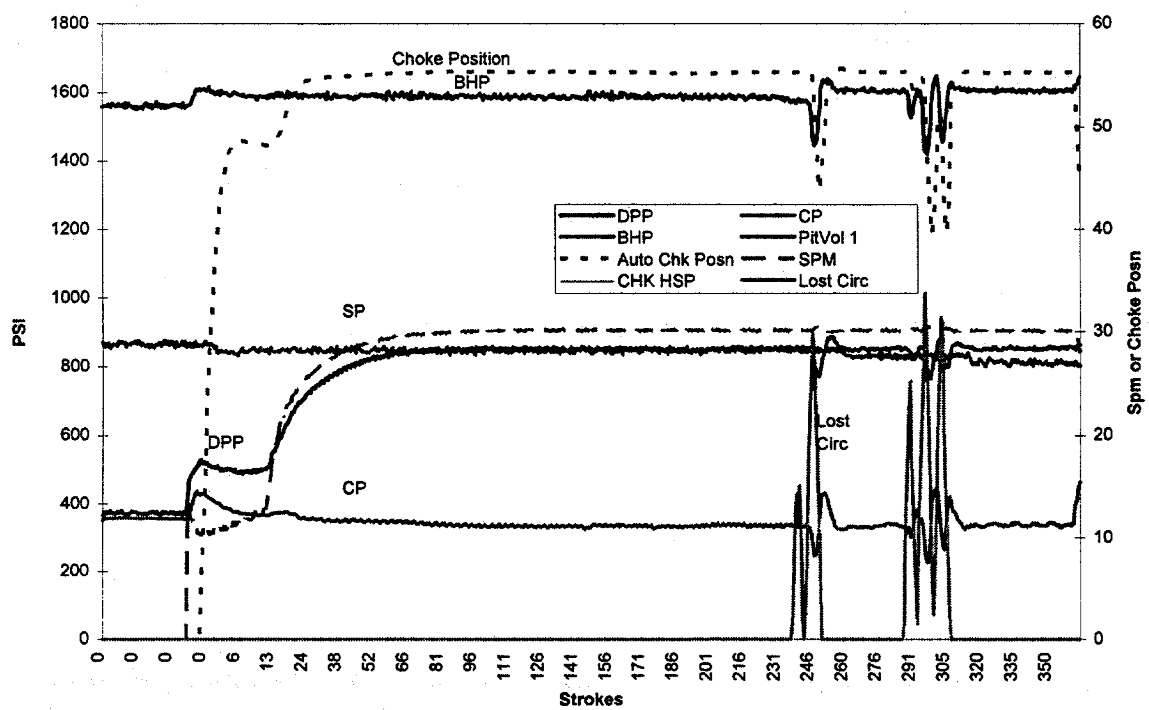
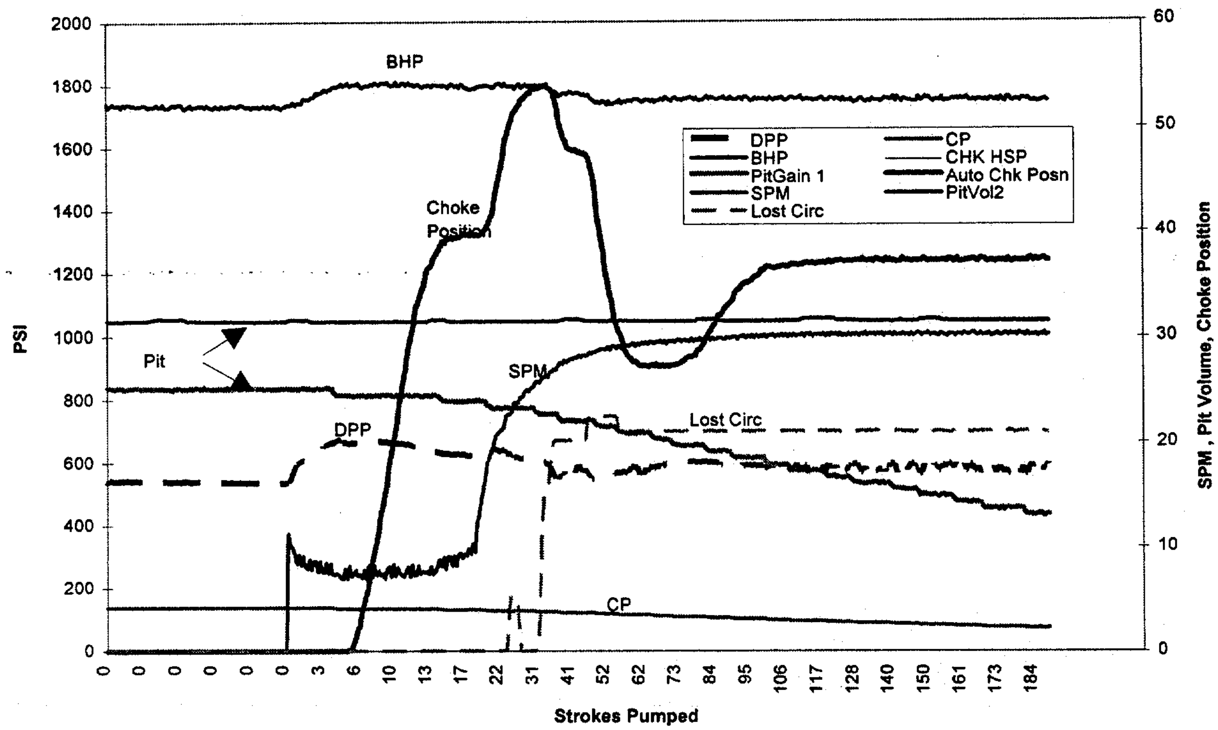


Figure 9 -- Lost Circulation to an Underground Formation



CEMENT SLURRY VIBRATION - A METHOD FOR PREVENTION OF FLOW BEHIND CASING

by
John P. Haberman, *Texaco EPTD*
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PART 2: TOP CEMENT RECIPROCATION (TCR) MODEL

by
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Louisiana State University

OBJECTIVE

The objective of this project task was to develop a theoretical model of cement slurry vibration as a method for preventing flow behind casing. The theoretical model is needed to help select the best pulse amplitude and frequency for a given field situation.

ABSTRACT

A theoretical study, reported in this paper provides analytical modeling support to TCR technology. Published research data and results from field tests, which were surveyed and analyzed in this work, support the TCR concept of periodic and intermittent breakdown of cement structure during its dormant period. A simple analytical model, which was developed in this research, relates TCR pulse amplitude to the entire distribution of pressure in cement column during and after TCR pulse. The model shows how much bottomhole pressure will be rebuilt by TCR thus preventing formation gas from invading the cement. The TCR model is an analytical tool for designing the desired increase of pulse amplitudes during early WOC time.

INTRODUCTION

The basic concept of the near cement vibration method [1] is to apply periodic or oscillating reciprocation (pulsating pressure) to the top of the cement slurry (TCR) after the slurry has been placed outside the casing in the annulus of the well. It is postulated that TCR will "*eliminate or reduce gelation*" of the slurry which in turn will eliminate early flow behind casing. It is also postulated that either "*the frequency, amplitude, and wave shape and time of application may be specifically tailored*" for well conditions. Another possible outcome is that the "*amplitude and frequency...may not be critical*" when using this technology. Hence, there is a need to show the physical mechanism by which TCR fluidizes the cements slurry at depth and to define critical factors for TCR design.

Field pilot testing of the TCR technology in a 300-ft well [2] with individual pressure pulses applied to the cement top and recorded at depth has shown an *increase of the pulse amplitudes with increasing depth.* The observation indicated that propagation of the pressure pulse was controlled by an amplification mechanism which was stronger than the mechanism of pulse attenuation. The only possible source of pressure pulse amplification can be attributed to potential energy stored in the cement column in the process of cement gelation. This energy is released by the propagating pressure pulse. However, the energy release is limited and dependent upon depth and size of the initial pressure pulse. On the other hand, strong and very frequent pulses may destabilize the borehole. Therefore, a mathematical model needs to be developed in order to design TCR technology. The mathematical model should describe pulse initiation, amplification and attenuation as a function of depth. To satisfy this need, a study has been undertaken at LSU to support the TCR technology with theoretical background and analytical tools. The objectives of the first stage of the study are as follows:

1- Compare TCR with conventional cement vibration methods and explain its unique mechanism;

2- Review research data on cements and define properties underlying the TCR technology;

3- Define critical parameters for the TCR design;

4- Develop mathematical model describing restoration of bottomhole pressure with TCR.

COMPARISON OF TCR TO OTHER CEMENT VIBRATION CONCEPTS

Cement vibration using a low-frequency cyclic pulsation is a well established method in the construction industry for improving quality of cement. The quality has been related to better compaction, compressive strength, and fill-up. Cement gelation or transmission of hydrostatic pressure has not been a concern in these applications.

In the oil industry the "vibration" of cement in wellbore annuli was initially considered as a *method for manipulating the casing string* in order to keep the cement slurry in motion through casing rotation or reciprocation [3,4,5]. The motion improved displacement of drilling mud and placement of cement slurry in the annulus. Similarly, enhanced filling of the annulus with a cement slurry ("*compactly placing... without rotating or reciprocating the casing*") was considered the main advantage of the first casing vibration method which used a mechanical vibrator placed at the bottom of casing string [6].

The use of forced casing vibrations for early gas migration control has become the subject of several inventions in the 80's and 90's [7,8,9,10,11]. Despite various types of vibration generators proposed in these inventions, the concept of gas migration control was the same. Based upon experimental observations, investigators found that cement slurries in continuous motion remained liquidous for longer period of time that for a still cement slurry. These observations have been supported by the following findings [12]:

1. Hammering at a steel pipe submerged in cement causes a concentric layer of slurry around the pipe to remain in a liquid state such that it could still flow while the outer slurry became gelled;

2. When low-frequency (8 cycles/sec) vibrations were applied to a casing string surrounded by cement slurry in a 200-ft well, bottomhole hydrostatic pressure was almost instantly (2-3 sec) restored as shown in Fig. 1;

3. Casing vibration caused instant compaction of the cement column (Fig. 2) which indicated a development of void spaces in the dormant slurry (i.e. building of structure and transition from liquid to semi-solid).

Using the casing to keep cement in motion has one fundamental dis-advantage. This method provides the same level of vibration at all depths, but the stage of the setting process at which a given portion of the cement slurry exists is a function of depth. The rate at which the slurry sets is a temperature-controlled process of hydration [13], and the annular cement usually starts to set from the bottom up due to the temperature distribution within the wellbore. (The temperature distribution may not be uniform, with the maximum temperature being at about one-third of the well's depth from the bottom [14]). The uniformly distributed vibration may liquefy cement in the upper annulus while damaging the cement-to casing bond and creating a micro-annulus in the lower annulus. On the other hand, the TCR technology imposes motion to the cement slurry directly at the slurry top without moving the casing. Moreover, the downward propagation of the pressure wave is limited by the structural strength of the slurry. Due to this limited propagation, TCR would *selectively fluidize* only the upper section of cement column which is at an early stage of gelation while leaving the lower section of the cement column (which may be set) unaffected.

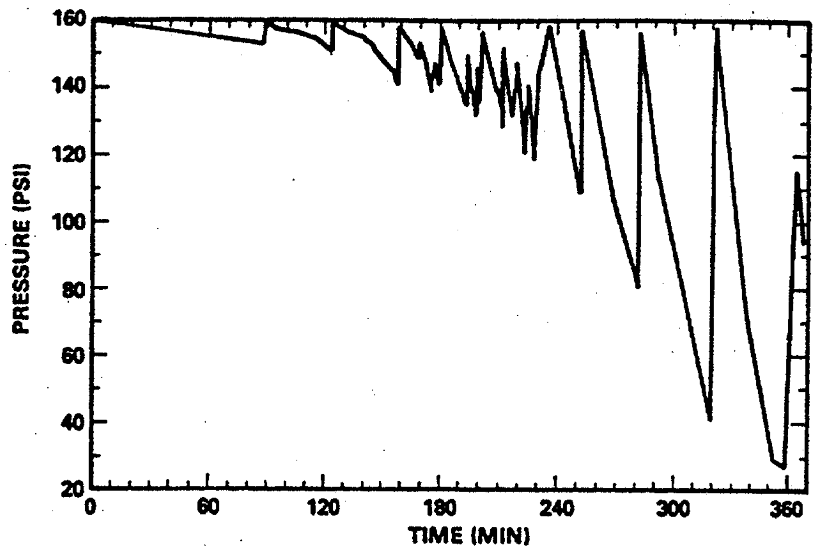

Figure 1. Instant restoration of bottomhole pressure in response to casing vibration [12].

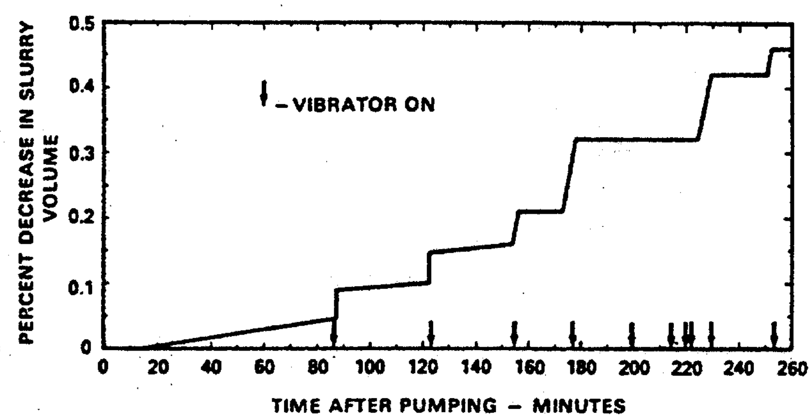

Figure 2. Liquification of cement slurry in response to vibration measured as instant drop of slurry level in annulus [12].

PHYSICAL MECHANISM AND TCR DESIGN PARAMETERS

The physical mechanism underlying the TCR concept may be explained by examining the phenomenon of the top pressure pulse amplification with depth and the possible source of potential energy storage in the cement. The effect was observed in the field tests when a 400-psi constant pressure load was applied to the top of cement in a 6,000-ft well [15]. The resulting increase of pressure below the top of the cement was greater than 400 psi and tended to increase with depth. As depicted in Fig. 3, the pressure reached over 1000 psi at a depth of XX ft.

A similar response was observed when a single cycle of pressure with a 60-psi amplitude was applied to cement slurry in 300-ft well [2]. The pressure signal was amplified to almost 100 psi at the bottom of the well. This observed pressure trend is consistent with the previously discussed example (Fig. 3) and is illustrated in Fig. 4.

The amplification of pressure signals with increasing depth is attributed to potential energy stored in the cement. This potential energy is thought to result from the fact that part of the hydrostatic pressure is supported by progressive gel strength. The development of static gel strength is well documented in the cementing literature for different types of cement slurries as shown in Fig.5. It has been also documented experimentally that development of gel strength can be altered by using low shearing rates as shown in Fig.6. This analysis together with the results depicted in Fig. 1 indicate that when shear is applied, the slurry responds by

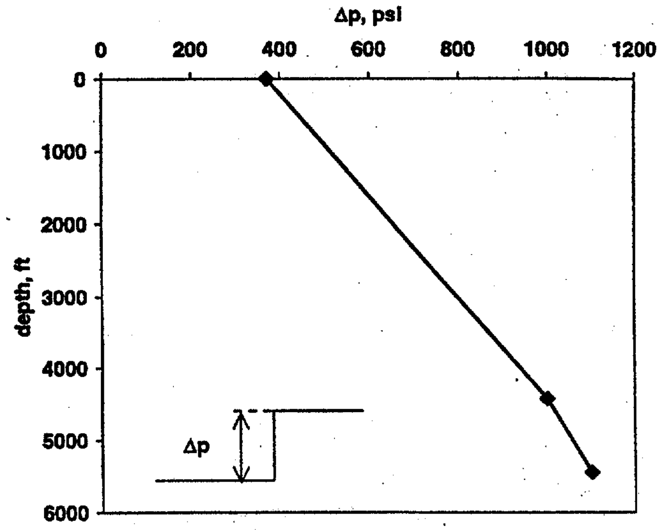

Figure 3. Step pressure increase at cement top is amplified with depth [15]

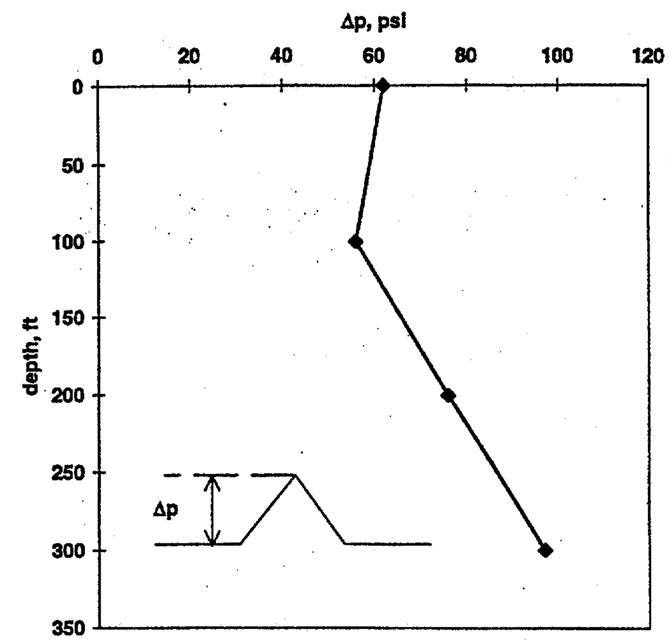

Figure 4. Top pressure cycle with 62-psi amplitude is amplified at depth [2].

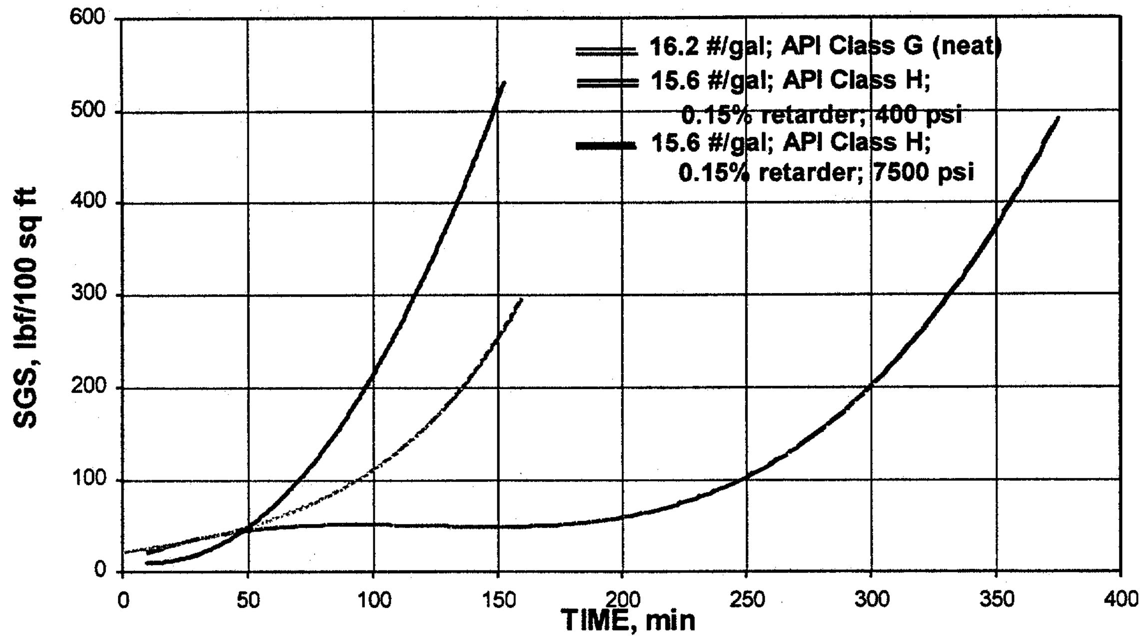

Figure 5. Development of static gel strength in time for various cement slurries [15,16]

reducing its resistance to flow from the upper curve (SGS) to the lower curve (Yield Point) in Fig. 6. Thus, the physical mechanism active in the application of TCR can be attributed to thixotropic, low-shear properties of cement slurries.

SHEAR-INDUCED STRUCTURAL BREAKUP OF CEMENT SLURRIES

The conceptual model of TCR technology developed in this study is based on the low-shear rheology of cement slurries. Within the low shearing-rate range the slurry response reveals both the thixotropic and viscoëlastic behavior. Experiments conducted with an oscillatory rheometer [18] showed that cement slurry rapidly builds up a basic solid-like structure (thixotropy) which is resistant to small shearing rates (10 μm amplitude at 10 Hz frequency). This behavior is illustrated by the curve on the left side of Fig.7. This structure can be broken down, however, if a sufficiently high value of shearing rate (1,000 μm amplitude at 10 Hz) is sustained for a 30-second

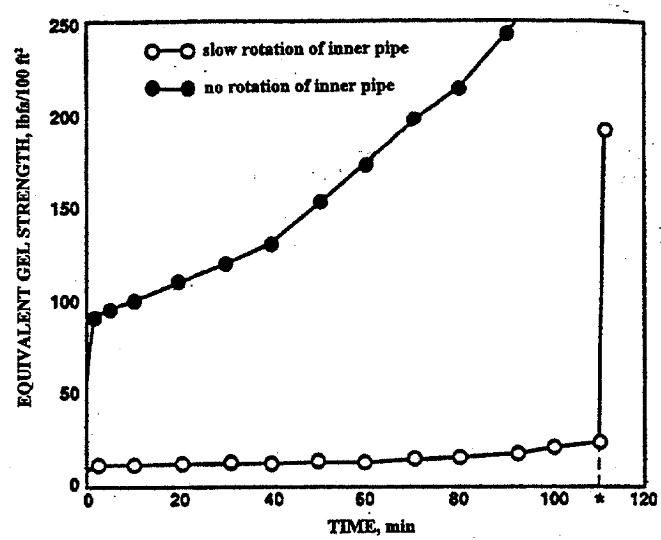

Figure 6. Two levels of cement slurry gelation: without shear (upper plot), and with shear (bottom plot) [17]

period of time (viscoelasticity). Also, the structure rebuilds in a few minutes even if low-level shear is continued.

Structural breakup of cement slurries has also been documented as a hysteresis of the shear stress vs. shear rate plots recorded with coaxial viscometers [19,20], shown in Fig. 8. In this research the hysteresis loops were attributed to the breakdown of the micro-structure (shear thinning) and its re-establishment (shear thickening). Therefore, it can be concluded that during setting time the slurry's flow resistance may assume two different values (upper and lower) for the same value of shear rate. Specifically, the upper value of stress at zero shear rate required to break the slurry's structure can be approximated with static gel strength while the lower value of stress at zero shear rate can be approximated with yield point. These approximations underlie the mathematical modeling of TCR technology.

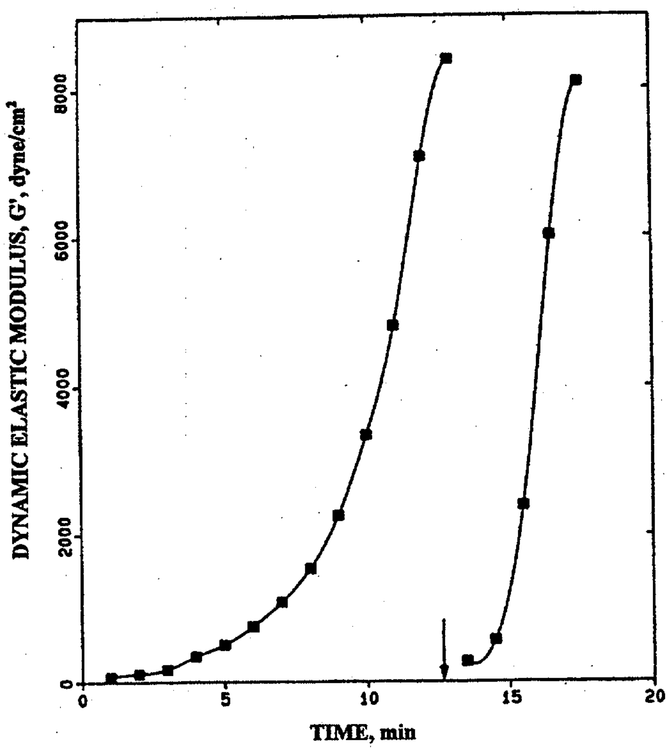

Figure 7. Breakup and rebuilding of cement slurry structure in response to 30-second long application of shearing rate [18]

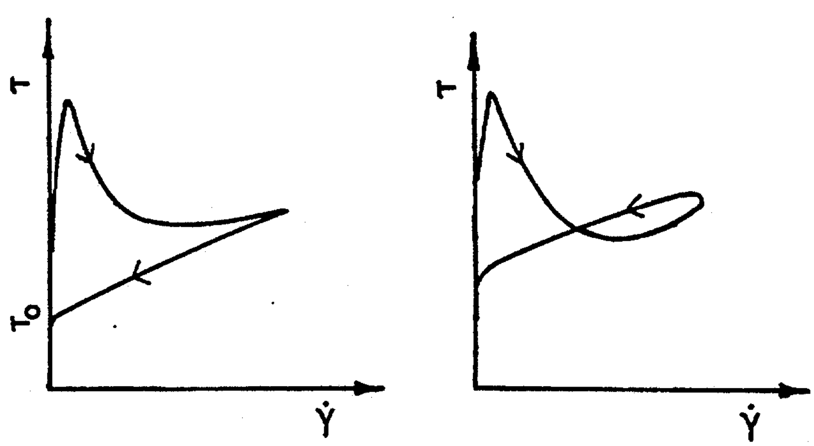

Figure 8. Gel strength and yield point values on cement rheogram hysteresis loops [19,20]

MATHEMATICAL MODEL OF TCR

The following assumptions were made when formulating the mathematical model:

1. Time-related values of SGS and YP are known from slurry testing;
2. Slurry behavior is elasto-plastic with negligibly small elastic strain range;
3. Duration of TCR step pressure top load is sufficiently longer than the duration of pressure transient effects.

Considering a balance of forces describing motion of any cross-section of cement column in the annulus of the well results in the following:

pressure gradient (up) - fluid weight (down) - wall stress (up) - inertial force (up) = 0

or,

$$-\delta p/\delta z + g\,\rho(p) - \delta p_f/\delta z - \rho\,\delta^2 u_z/\delta t^2 = 0 \qquad (1)$$

Neglecting transient effects and relating gel breaking pressure (p_f) to plastic limit (Y) yields the following expression:

$$dp = (g\,\rho - 4Y/\Delta D)\,dz \qquad (2)$$

Based on the definition of compressibility, density can be expressed as the following function of pressure:

$$\rho = \rho_o\, e^{c(p - p_0)} = \rho_o\, e^{c\,\Delta p} \qquad (3)$$

The pressure increase as a funtion of depth may be expressed as follows:

$$dp = (g\,\rho_o\, e^{c\,\Delta p} - 4Y/\Delta D)\,dz \qquad (4)$$

Integrating Equation (4) yeilds the following relationship between pressure and depth:

$$\int_0^p (dp/e^{c\,\Delta p}) = (g\,\rho_o\, e^{c\,\Delta p} - 4Y/\Delta D) \int_{zo}^{z} dz \qquad (5)$$

or

$$e^{c\,\Delta p} - 1 = -c\,(g\,\rho_o - 4Y/\Delta D)\,(z - z_0) \qquad (6)$$

or

$$p(z) = p_0 - (1/c)\ln[1 - c\,m\,(z - z_0)] \qquad (7)$$

where:

$$m = g\,\rho_o - 4Y/\Delta D \qquad (8)$$

Equation (7) describes pressure at depth for a slurry having a uniform structural strength throughout the annulus. If the compressibility of the well-slurry system is small, Equation (3) can be simplified using the Tailor series expansion around a point (p,ρ) as $\rho = \rho_o\ (1 + c\ \Delta p)$. The pressure formula becomes as follows:

$$p(z) = p_0 + (1/c)\ \{\exp[c\ m\ (z-z_0)] - 1\} \qquad (9)$$

For small compressibilities Equations (7) and (9) give almost identical results.

It can be proven that when a TCR pulse (p_0) is applied to a slurry characterized by static gel strength (G) and yield point (Y) there exists a critical depth (Z) of slurry structure breakdown for each value of p_0., The slurry yields at the yield point above the critical depth while static gel strength controls structural breakdown below the critical depth. Critical depth may be calculated as follows:

$$Z = \frac{p_0 - Y}{4Y} \Delta D \qquad (10)$$

Bottomhole pressure gradients in the annulus above and below the critical depth are different due to different structural strengths of cement in these two sections. Pressure at any depth can be calculated from Equations (7) or (9) by using the following substitutions:

$z_0 = 0$; and, Y = yield point; for $z \leq Z$; and,

$z_0 = Z$; and, $Y = G$; for $z \geq Z$.

RESULTS AND DISCUSSION

Using the mathematical model one can predict a change in bottomhole pressures and design an appropriate amplitude of the TCR pressure pulse. The concept of bottomhole pressure control with TCR is shown in Fig.9. Clearly, a relatively small pressure load may restore bottomhole pressure that has been lost due to gelation. The restored pressure is maintained even after the load is removed. Therefore, TCR may not require pressures large enough to fracture the formation.

Also, with this mathematical model the TCR pulse amplitude may be related to the entire pressure change in the hole's annulus. Therefore, proper design of TCR should consider an increase of pressure above the initial slurry gradient during the TCR treatment. However, most of the increased pressure section will be contained in the upper casing. Moreover, the amplitude of TCR pulse can be designed such that the previous casing will not be fractured.

Another design parameter is the magnitude of the increase of bottomhole. In most cases the bottomhole pressure should be restored to the level such that a possible gas or brine invasion will be eliminated. The target bottomhole pressure is not necessarily the pressure at the end of slurry placement. Therefore, an optimum amplitude of TCR pulse can be determined for a specific set of borehole conditions as shown in Fig.9.

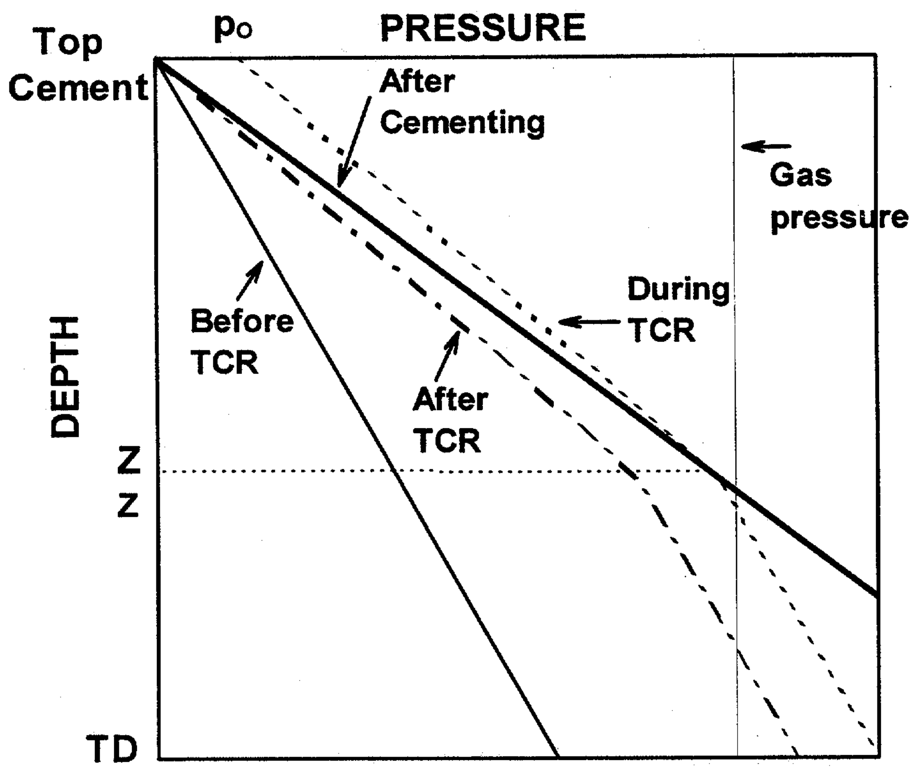

Figure 9. Conceptual change of pressure in cement column resulting from TCR pulse, p_0

An example calculations of TCR method is presented below using the following input data:

- 16-in conductor pipe at 1,000 ft;
- 10 $^3/_4$-in surface pipe at 4,045 ft;
- TCR pulse amplitude, p_0 = 300 psi;
- 13.8 lb/gal cement slurry;
- Cement slurry properties 2 hrs after cementing are as follows:
  - static gel strength, G = 450 lb/100 sq.ft.;
  - yield point, Y = 150 lb/100 sq.ft.;
  - system compressibility, $c = 125 \cdot 10^{-6}\ ^1/\text{psi}$

The results are shown in Fig.10. Comparison of the plots "Before TCR" and "After TCR" shows that the difference of the two pressures increases with increasing depth. Thus the mathematical model verifies results and observations made in the field experiments reported above in Figs. 3 and 4. Other results of the TCR example calculations are summarized in Table 1.

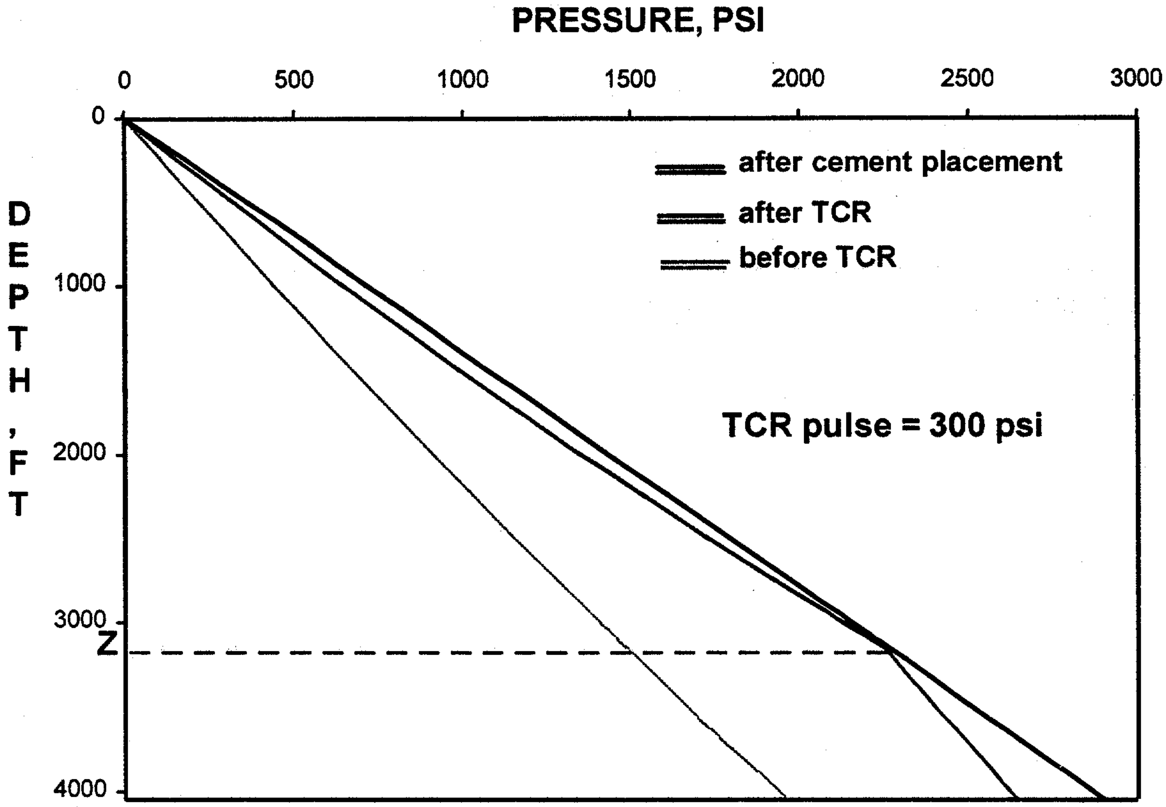

Figure 10. Predicted restoration of bottomhole pressure with TCR

TABLE 1 - Summary for TCR Calculations (200-psi amplitude)

PARAMETER	UNIT	VALUE
Depth of TCR influence, Z	ft	3,150
Initial pressure @ Z	psi	2,260
Pressure @ Z during TCR	psi	2,548
Initial pressure @ TD	psi	2,903
Pressure @ TD before TCR	psi	1,961
Pressure @ TD during TCR	psi	2,942
Pressure @ TD after TCR	psi	2,641
Initial pressure gradient	psi/ft	0.75
Maximum pressure gradient due TCR	psi/ft	0.81
Depth of maximum pressure gradient	ft	3,150

CONCLUSIONS

1. Scientific evidence supports the concept of periodic and intermittent breakdown of cement structure during its dormant period. Duration of resting periods (between TCR pulses) is a design variable to be determined.
2. A simple analytical model has been developed which relates TCR pulse amplitude to the entire distribution of pressure in the cement column during and after a TCR pulse. The model reveals that the lower portion of the cement column may remain unaffected be TCR. Also, the model provides analytical tool for designing the desired TCR amplitudes that should be increased with time.
3. This research provides a theoretical proof of the behavior observed in the field experiments involving amplification of the top pressure load with depth during TCR. Moreover, the analytical model suggests that the amplifying effect will diminish below a critical depth.

NOMENCLATURE

p = pressure

z = depth

g = acceleration of gravity

p_f = pressure opposing slurry motion

t = time

u_z = vertical displacement

ρ = density

Y = plastic limit, or yield point

G = static gel strength

ΔD = difference of annular diameters

c = compressibility

p_0 = top pressure amplitude

ρ_o = top cement density

z_o = depth at the top of section of interest

m = constant defined by Equ.(8)

Z = critical depth of TCR pulse influence

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NOTES:

SUMMARY AND CONCLUSIONS

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WORKSHOP EVALUATION FORM, DAY 2

Session	Evaluation of Session				Comments
	Excellent	Good	OK	Not Needed	
Research Program Overview					
Improvements in LSU/MMS Research and Training Well Facility					
Feasibility Study of Dual Density System for Deepwater Drilling					
Finite Element Analysis of Soft Sediment Behavior During Leak-off Tests					
Density, Strength, & Fracture Gradients for Shallow Marine Sediments					
Drill String Safety Valve Test Program					
Low Torque Drill String Safety-Valve Design					
Post Analysis of Recent Blowouts and Near Misses					
Automated Detection of Underground Blowouts					
Cement Slurry Vibration as Method for Prevention of Flow Behind Casing					
Overall Program					

GENERAL COMMENTS AND SUGGESTIONS:

Please indicate your category below

- ☐ MMS Headquarters Representative
- ☐ MMS Pacific Region Representative
- ☐ MMS Gulf Coast Region Representative
- ☐ Research Industrial Sponsor
- ☐ Industry Representative
- ☐ Other:__________________

SUGGESTED TOP RESEARCH PRIORITIES:

Please rate your hotel accomadations:

- ☐ Highly Recommended
- ☐ Recommended
- ☐ Satifactory
- ☐ Unsatifactory
- ☐ Poor

Name of Hotel: __________________

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