LOUISIANA STATE UNIVERSITY
MINERALS MANAGEMENT SERVICE
ROTAC Meeting and Well Control Research Status

Wednesday, April 1, 1998
8:30 A.M.-3:00 P.M.

Pennington Biomedical Research Center, LSU
6400 Perkins Road, Baton Rouge, Louisiana

OBJECTIVES & SCOPE

The second day of the 1998 LSU/MMS workshop will focus on the problem of sustained casing pressure (SCP) and the review of ongoing research at LSU. The Regional Operations Technical Assessment Committee (ROTAC) of the Minerals Management Service will lead discussion on regulating aspects and potential solutions for SCP. The industry will present new techniques currently under development. In addition, LSU will report on the results of the SCP research that we have been doing in this area.

Later in this meeting, the LSU Petroleum Engineering Department will review ongoing research on well control being supported by the MMS and by Industry. The industry survey will be presented regarding present status of the flow-after-cementing prevention technology with emphasis given to a novel mechanical technique of cement pulsation for maintaining bottomhole pressure and preventing gas invasion into the cement. Also discussed will be the recent results from testing reliability of drill string safety valves; a LSU research project providing new data for the API Task Force on Drill String Safety Valves. Other well control topics presented by the LSU team will include the diagnosis of risk of annular channelling resulting from shallow leak-off tests offshore and the procedures for controlling gas kicks in horizontal wells.

WEDNESDAY, APRIL 1, 1998

Regional Operations Technical Assessment Committee Meeting: "Sustained Casing Pressure"	8:30 A.M.	1.	**INTRODUCTION AND WELCOME** Adam T. Bourgoyne, Jr., *LSU*
	8:45 A.M.		**SUSTAINED CASING PRESSURE REPORT** Stuart Scott, *LSU*
	9:15 A.M.	2.	**CASING-ANNULUS REMEDIATION SYSTEM (CARS)** Noel A. Monjure, *ABB Vetco Gray*
	9:45 A.M.	3.	**MMS FOLLOW-UP: WHAT'S NEXT?** Jim Regg, *MMS*
	10:00 A.M.	**COFFEE**	
LSU Well Control Research	10:25 A.M.	4.	**OVERVIEW OF LSU RESEARCH** Adam T. Bourgoyne, Jr., *LSU*
	10:55 A.M.	5.	**MAPPING OF THE GAS FLOW HAZARD AFTER CEMENTING** Andrew Wojtanowicz and Somei Nishikawa, *LSU*
	11:15 A.M.		**FLOW AFTER CEMENTING -- A NEW PREVENTION METHOD** Wojciech Manowski, *Dowell-Schlumberger* and Andrew Wojtanowicz, *LSU*
	11:45 A.M.	**LUNCH**	
	1:15 P.M.	6.	**DRILL STRING SAFETY VALVE RELIABILITY** Lyndon S. Stephens, *LSU*
	1:45 P.M.	7.	**LEAK OFF TESTING IN UMS** Andrew Wojtanowicz, *LSU*
	2:15 P.M.	8.	**GAS KICKS IN HORIZONTAL WELLS** John Smith and Dimitris Nikitopoulos, *LSU*
	2:45 P.M.		**DISCUSSION**
	3:15 P.M.		**SUMMARY & CONCLUSIONS**
	3:30 P.M.	**TOUR OF WELL CONTROL FACILITY**	

model will predict time to underbalance

GRI is looking at further research

EVALUATION

ROTAC Meeting and Well Control Research Status

April 1, 1998

Session	Evaluation of Workshop Activity				Comments
	Excellent	Good	OK	Poor	
1. Sustained Casing Pressure Report					
2. Casing-Annulus Remediation System (CARS)					
3. MMS Follow-Up: What's Next					
4. Overview of LSU Research					
5a. Mapping Of the Gas Flow Hazard After Cementing					
5b. Flow After Cementing - A New Prevention Method					
6. Drill String Safety Valve Reliability					
7. Leak-Off Testing In Upper Marine Sediment					
8. Gas Kicks In Horizontal Wells					
Discussion					
Overall Workshop					

General Comments and Suggestions:

Table of Contents

Chapter 1

comment on draft report

A REVIEW OF SUSTAINED CASING PRESSURE (SCP) OCCURRING ON THE OCS

Adam T. Bourgoyne, Jr., LSU

Stuart L. Scott, LSU

Wojciech Manowski, Dowell-Schlumberger

Executive Summary

Sustained casing pressure (SCP) is seen in over 11,000 casing strings in over 8000 wells on the OCS. Reporting and record keeping requirements associated with sustained casing pressure requires a major effort on both the offshore oil and gas industry and on the Minerals Management Service. This is a first draft of a final report of work done at LSU under MMS sponsorship to review the SCP problem. Comments and suggestions are being solicited.

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 MMS and operators on the magnitude of the sustained casing pressure problem,
2. Compile information from the literature and from offshore operators on various 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 assisting in the development of new technology for reducing the number of future problems.

An MMS database on sustained casing pressure was made available for confidential internal use by the LSU research team. Database software was developed to assist with queries and data retrieval by the research team. Sustained casing pressure is seen in over 11,000 casing strings in over 8000 wells on the OCS. Reporting and record keeping requirements associated with sustained casing pressure requires a major effort on both the offshore oil and gas industry and on the Minerals Management Service.

Example areas were selected for further study from an analysis of the database. Procedures currently followed in industry for handling excessive casing pressure have been discussed with a number of operators. Members of the research team made several offshore trips to witness diagnostic test procedures and various remediation procedures. Data were provided by several of the operators showing the results of the remediation attempts over an extended period. Meetings were also held with service companies that were conducting research aimed at identifying the causes of the problem and developing new technology aimed at solving the problem. Pressure and temperature changes introduced by completion and production operations have been shown to contribute to the development of cracks and micro-annuli (Jackson & Murphey, 1993 and Goodwin & Crook, 1990) in the cement sheath.

Industry experience with problems resulting from sustained casing pressure has shown that the most serious problems have resulted from tubing leaks. When the resulting pressure on the production casing causes a failure of the production casing, the outcome can be catastrophic. The outer casing strings are generally weaker than the production casing and will also fail, resulting in an underground blowout. Flow rates through the tubing leak can quickly escalate if any produced sand is present in the flow stream. Thus, blowouts of sufficient flow rate to jeopardize the production platform are possible. The magnitude of the leak rate is as important as the magnitude of the pressure when determining the potential hazard posed by sustained casing pressure.

Industry experience on the OCS has also shown that there has been only minor pollution and no known injuries or fatalities due to problems related to SCP. This study has indicated that further substantial reductions in the regulatory efforts to manage the SCP problem on the OCS are possible without sufficiently increasing the risk of injury to offshore personnel or the risk of pollution. The regulatory burden associated with managing sustained casing pressure was significantly reduced by a series of LTL's issued since 1991. Further substantial reductions in the regulatory efforts to manage the sustained casing pressure (SCP) problem on the outer continental shelf (OCS) appear to be possible without significantly increasing the risk of injury to offshore personnel or the risk of pollution.

Recommendations are given concerning changes in the regulation of SCP and concerning additional research for reducing the magnitude of the SCP problem.

Chapter 2

Introduction

The Minerals Management is concerned about wells on the Outer Continental Shelf (OCS) that exhibit significant sustained casing pressure because of its responsibility for worker safety and environmental protection as mandated by congress.

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.

What is Sustained Casing Pressure ?

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 (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 250.87 state that the lessee shall immediately notify the MMS District Supervisor if sustained casing pressure is observed on a well. If the well is felt to be in an unsafe condition, the district supervisor can order that remedial actions be taken. However, provisions are made for a departure from 30 CFR 250.87 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 CFR250.87. 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.

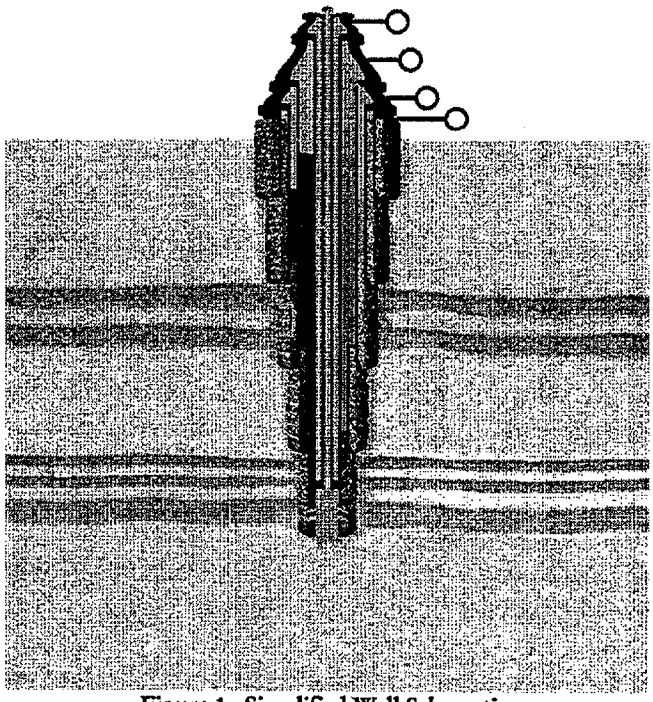

Figure 1 - Simplified Well Schematic.

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.

Chapter 3

Overview of Problem

Industry experience with problems resulting from sustained casing pressure has shown that the most serious problems have resulted from tubing leaks.

T principle concern for wells that exhibit a sustained casing pressure is that a down-hole situation is developing or has developed that can result in an underground blowout. Wells are designed so that the innermost casings are the strongest. Only the production casing is designed to withstand the pressure of the deepest producing formation. Thus production casing provides a redundant barrier to a blowout in the event of a failure of the production tubing. This redundant protection allows the tubing to be safely repaired. However, if a tubing leak develops and pressure is allowed on the production casing, there is no longer a redundant barrier present. If the production casing fails, the next outer casing string is generally not designed to withstand formation pressure.

Risks Associated with Sustained Casing Pressure

Industry experience with problems resulting from sustained casing pressure has shown that the most serious problems have resulted from tubing leaks. When the resulting pressure on the production casing causes a failure of the production casing, the outcome can be catastrophic. The outer casing strings could also fail, resulting in an underground blowout. Flow rates through the tubing leak can quickly escalate if any produced sand is present in the flow stream. Thus, blowouts of sufficient flow rate to jeopardize the production platform are possible. The magnitude of the leak rate is as important as the magnitude of the pressure when determining the potential hazard posed by sustained casing pressure.

Case Histories of Problems Caused By SCP

The potential problem 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 asnd 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. It is believed that the production casing became pressurized through tubing or packer leaks. Failure of the production casing led to pressure on the outer strings through which the blowout occurred.

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 sidetracked during drilling operations because of a stuck drill string. The foundation below one of the platform legs was eroded and the platform began to shift and settle. This platform leg failed below the mudline. 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 two years of blowout control and remediation work. Holes in the production tubing at and below about 1500 ft were found during the remediation work. The next two outer casing strings had also failed in the vicinity of the tubing.

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 through 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.

Occurrence of Sustained Casing Pressure

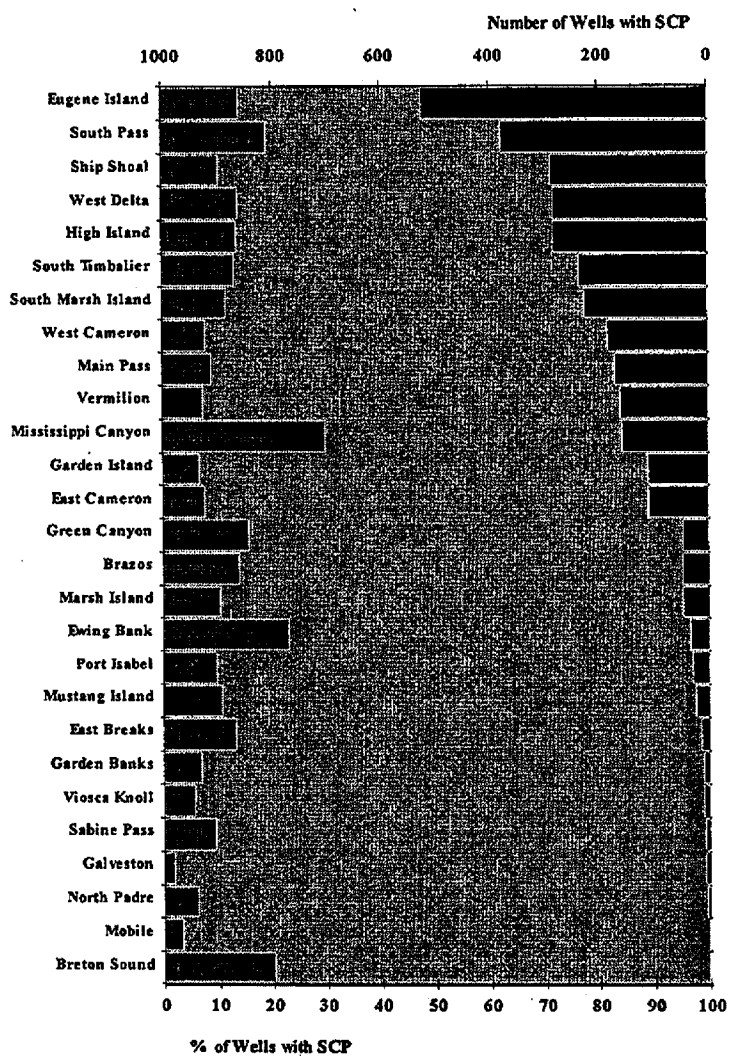

Figure 3.1 : Sustained Casing Pressure by Area

GOM - MMS 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. The second category includes wells that have pressure on outer casing strings. Wells having pressure only on the production casing can generally be more easily repaired than wells with pressure on outer casing strings.

Geographical Distribution within GOM

Shown in Figure 3.1 is a summary of the occurrence of SCP in the Gulf of Mexico OCS region by block. Note that the occurrence of SCP is widespread and affects a large number of wells.

Casing Strings Affected

As indicated by the bar graphs shown in **Figure 3.2** and **Figure 3.3,** the following trends may be observed:

- About 50% of the casing strings exhibiting sustained casing pressure are *production* casing.
- About 10% of the casing strings exhibiting sustained casing pressure are *intermediate* casing strings.
- About 30% of the casing strings exhibiting sustained casing pressure are *surface* casing strings.
- About 10 % of the casing strings exhibiting sustained casing pressure are *conductor* casing strings.

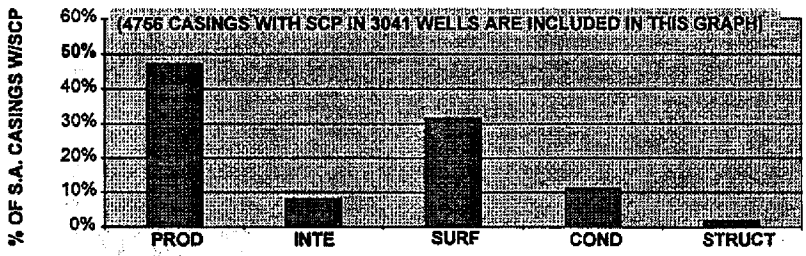

Figure 3.2 Self-approved Sustained Casing Pressure by Casing String.

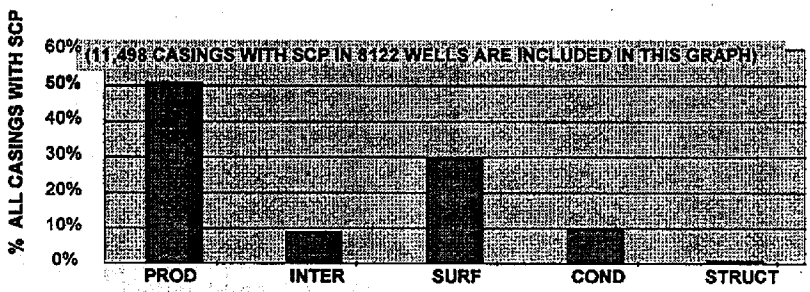

Figure 3.3: Sustained Casing Pressure in Combined Database by Casing String.

Magnitude of SCP by Casing String

Shown in **Figure 3.4** is a cumulative frequency plot of the occurrence of the magnitude of the SCP in units of psi for the various types of casing strings. Note that about 80 percent of the production casings and intermediate casings with SCP are less than 1000 psi. For the other casing strings, about 90 percent of the strings have SCP values less than 500 psi.

Figure 3.5 shows the cumulative frequency of SCP for all casing strings by pressure for wells with self-approved departures. Figure 3.6 gives this same information for all wells with SCP. These plots show that about 90 % of sustained casing pressures observed are less than 1000 psi in magnitude.

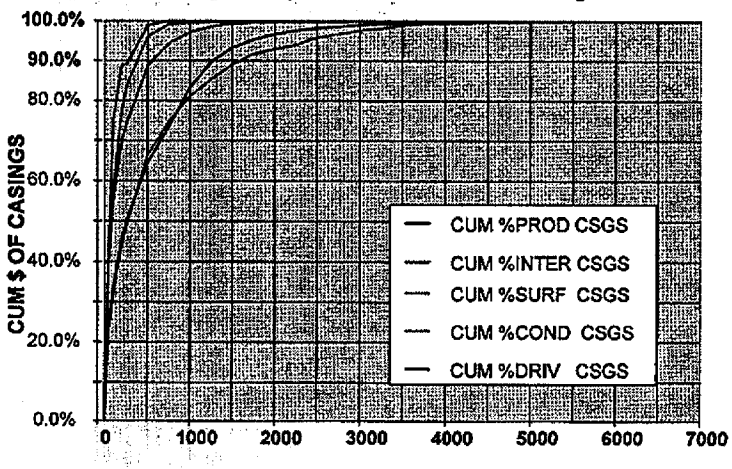

Figure 3.4: Pressure Distribution by Occurrence in Each Casing.

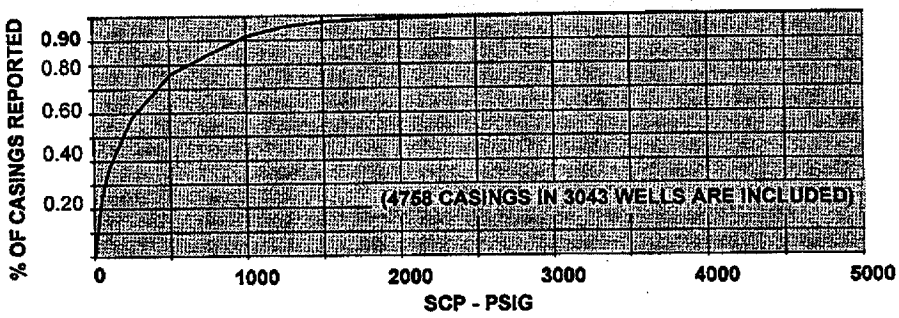

Figure3.5: Cumulated percent of Casings with self-approved SCP less than plotted.

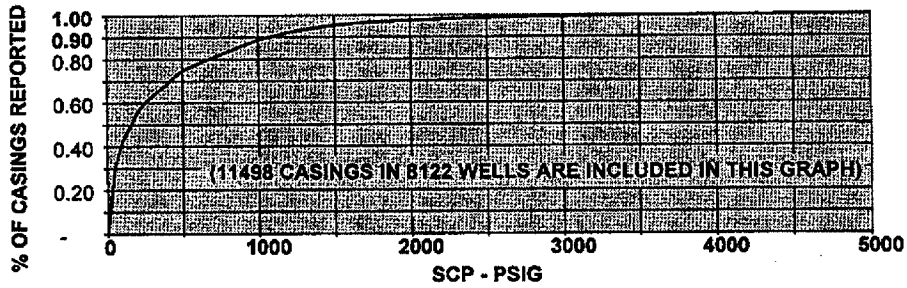

Figure 3.6: Cumulated percent of all casings with SCP less than plotted.

Figure 3.7 shows the same information as a percentage of minimum internal yield pressure. As indicated by Figure 3.7, more than 90% of all sustained casing pressures observed are less than 30 % of the minimum internal yield pressure (burst pressure) of the casing involved. Data on the collapse pressure of the inner string exposed to the SCP are not available. On old shut-in or abandoned wells, failure of the inner string due to SCP may also be of concern.

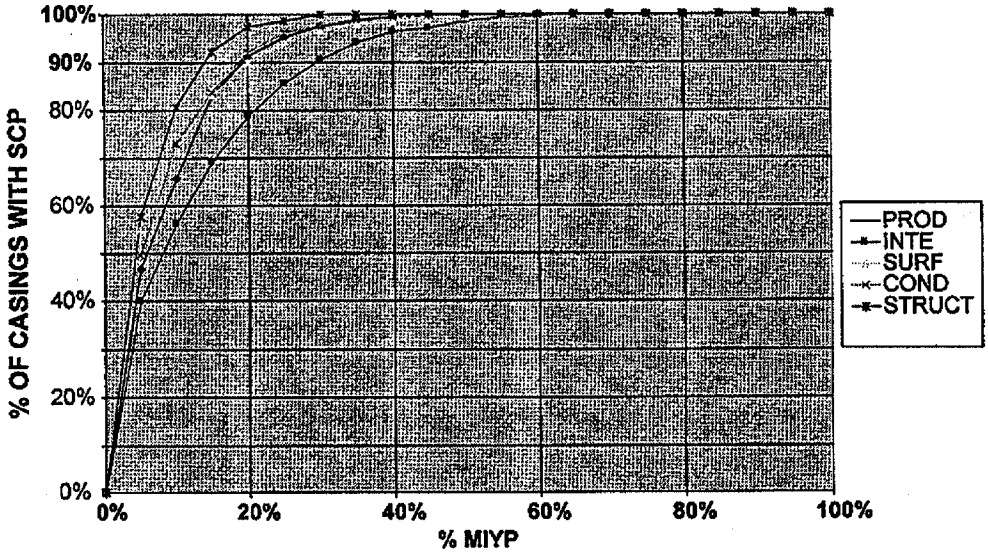

Figure 3.7: SCP distribution as a percentage of Minimum Internal Yield Pressure.

Occurrence by Type of Well

As shown by **Figure 3.8** and **Figure 3.9**, only about one-third of the casing strings exhibiting sustained casing pressure are in wells that are active and producing. Thus the majority of wells showing SCP are in wells that are shut-in or temporarily abandoned. Additional information regarding the type of wells with SCP are shown in **Table 3.1**. About equal numbers of oil wells and gas wells have casing strings with SCP.

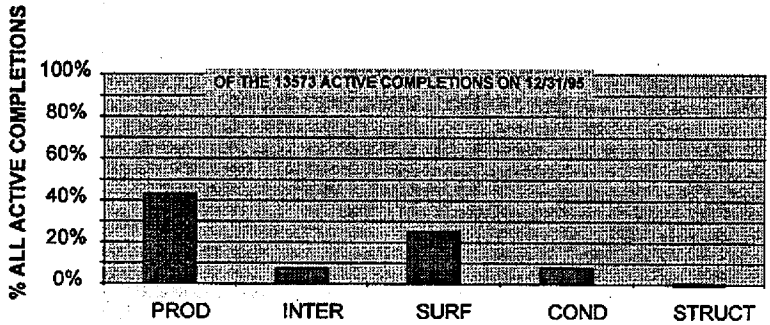

Figure 3.8: Percentage of Active Completions with Self-approved SCP.

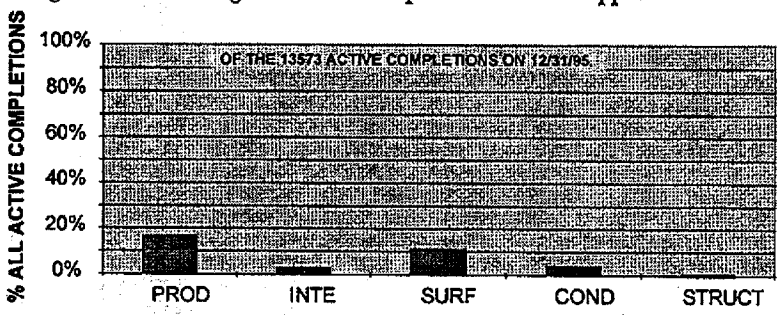

Figure 3.9: Percentage of All Active Completions with SCP.

Regulatory Requirements

General Requirements for Exploration, Development and Production (30 CRF 250.3)

All exploration, development and production activities are regulated by 30 CRF 250.3 which requires the lessee or a group of lessees to submit a proposed plan for the activity which is subject to the approval of the MMS Regional Supervisor. The lessee may propose to use new or alternative techniques so long as the alternative technique is equal to or better than the conventional technique with regards to safety, performance, and protection. The proposed plan should incorporate industry standards and recommended practices. Written approval from MMS is required prior to implementation of any planned activity.

Regulatory Background on Sustained Casing Pressure

In 1988, the regulations existing at that time were consolidated and included in 30 CFR 250.87. These regulations required that all annuli be monitored for sustained casing pressure and that every occurrence of sustained casing pressure be reported immediately to the District Supervisor. Implementation of this regulation imposed a heavy regulatory burden on both the lessee and the MMS. As a result, discussions were initiated between MMS and the OOC. After some discussion the OOC commenced a study of sustained casing pressure.

In 1989, the MMS and OOC resumed their discussions and held meetings to present the results of the OOC's study. Based on the results of the study, the MMS decided to streamline the departure process as recommended by the OOC study. The MMS developed new reporting procedures which were intended to reduce the volume of burdensome paperwork required by sustained casing pressures.

Table 3.1: Sustained Casing Pressure by Type of Production and Well Status.

TABLE I

TYPE OF PRODUCTION-CIRCA DEC 1995

SELF APPROVED SUSTAINED CASING PRESSURE WELLS

TYPE OF PRODUCTION	WELLS	SCP CASINGS-STATUS OF 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	4758	1440	1932	1386

ALL SUSTAINED CASING PRESSURE WELLS

TYPE OF PRODUCTION	WELLS	SCP CASINGS-STATUS OF 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	11498	3542	5459	2497

In 1991, a Letter to the Lessees (LTL) was issued which dictated the changes in the sustained casing pressure policy. Prior to the issuance of the 1991 LTL, the results of *bleed down* and *build up* diagnostic tests had to be submitted to MMS for evaluation. If upon evaluation of the results MMS were to find that the well met the requirements for continued operation, the well would be approved for continued operation. The requirements for continued operation are as follows:

1. The sustained casing pressure is less than 20% of the minimum internal yield pressure, AND
2. The casing pressure bleeds to zero during the diagnostic tests.

As of the 1991 LTL, the diagnostic tests which met both of the requirements for continued operation were no longer required to be submitted for evaluation and approval. Wells meeting both of these criteria for self-approval were placed in a separate category and referred to as *Self-approved.* Self-approved wells were allowed to continue operations as long as operations adhered to the following conditions:

1. Well(s) with SCP must be monitored monthly and records of the sustained casing pressures observed and of any diagnostic test performed must be maintained and made available to MMS for inspection.

2. If the casing pressure increases by 200 psi or more in the intermediate or production casing or by 100 psi or more in the conductor or surface casing, a diagnostic test must be conducted to re-evaluate the well. If either of the following conditions apply, the records of the diagnostic test must be submitted to MMS for evaluation:

   a) The casing pressure is greater that than 20% of the minimum internal yield pressure for the casing in question, OR
   b) The casing pressure fails to bleed to zero during the diagnostic test.

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

3. Initiation of any workover operations on the well(s) invalidate such approval.

4. The casing should not be bled down without notifying MMS , except when performing a diagnostic test required by condition no. 2 above.

In 1994, a second Letter to Lessees concerning sustained casing pressure reporting policy was issued which superseded the 1991 LTL. The intent of the 1994 LTL was to clarify the policy changes stated in the 1991 LTL. The 1994 LTL clarified the 1991 policy changes regarding reporting and data submittal requirements, time to respond to a denial of continued operation, and unsustained pressure and subsea wells.

In 1995, a third Letter to Lessees concerning sustained casing pressure reporting policy was issued. The intent of the 1995 LTL was to summarize the evolution of the current sustained casing pressure reporting policy and to further clarify the policy changes implemented in 1991. The 1995 LTL states that requests for sustained casing pressure departure should be requested on a well basis rather than per casing string. The SCP on each casing string must be reported and a positive statement given regarding the casing strings that do not exhibit SCP. The 1995 LTL also ordered each operator to submit a status report on all SCP self-approved wells. Along with a listing of the SCP self-approved wells, MMS ordered that the most recent pressures on all annuli in each well be included in the report:

Current Practice

The current sustained casing pressure reporting practice is set by the Letter to the Lessees issued on January 13, 1994. All casing head pressures, excluding drive or structural casing, must be reported ti the District Supervisor immediately. The notification may be in writing or by telephone but must be no later than the close of business on the following working day. Diagnostic tests are required on a casing string when sustained pressure is first discovered and on a self-approved SCP well which exhibits the previously specified increase in sustained casing pressure.

Request for Departure

A departure is automatically granted to wells which meet the criteria (discussed previously) to qualify as a self-approved well. If the well no longer meets the criteria established to qualify for self-

approved status, a request for departure must be submitted to MMS. A request for departure should contain the following information for EACH casing annulus with sustained casing:

- identification of casing annulus,
- magnitude of the pressure on each casing string prior to bleeding down,
- time required to bleed down through 0.5-inch needle valve,
- type of fluid recovered
- volume of fluid recovered,
- current rate of build-up shown graphically or tabularly in hourly increments of time,
- current shut in tubing pressure,
- current flowing tubing pressure,
- current production data, and
- current well status.

Should a request for a departure from 30 CFR 250.87 be denied, the operator must submit a plan to eliminate the sustained casing pressure. The correction plan must be submitted within 30 days of the departure denial unless MMS specifies otherwise for a particular condition. Departures are granted on a well basis if MMS judges that the well in question does not present a hazard to the offshore personnel, platform, formation, or the environment. The granting of a departure allows the well to continue producing without elimination of the sustained casing pressure. The departure may be granted on an annually, indefinitely (life of completion, or under special circumstances. A departure might be granted subject to annual review if the sustained casing pressure is greater than 20% of the minimum internal yield pressure AND the casing pressure bleeds to zero.

The departure requests are processed through the TAOS Section which issues the departures either verbally or in writing. The TAOS section also coordinates policy decisions. The District Office is responsible for handling the initial reports of sustained casing pressure and any follow-up actions which might be required following a denial of a request for departure. Special projects involving remediation of sustained casing pressure are addressed by both of these offices.

Chapter 4

Origins of Sustained Casing Pressure

Tubing leaks, casing leaks, and the establishment of flow paths through the cemented annulus. Portland cement is a brittle material and susceptible to cracking when exposed to thermally induced or pressure induced tensile loads.

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 which are listed below and illustrated in **Figure 4.1**:

- Tubing and Casing leaks .
- Poor primary cement (i.e., channel caused by flow after cementing) .
- Damage to primary cement after setting (i.e., tensile crack due to temperature cycles, micro-annulus due to casing contraction).

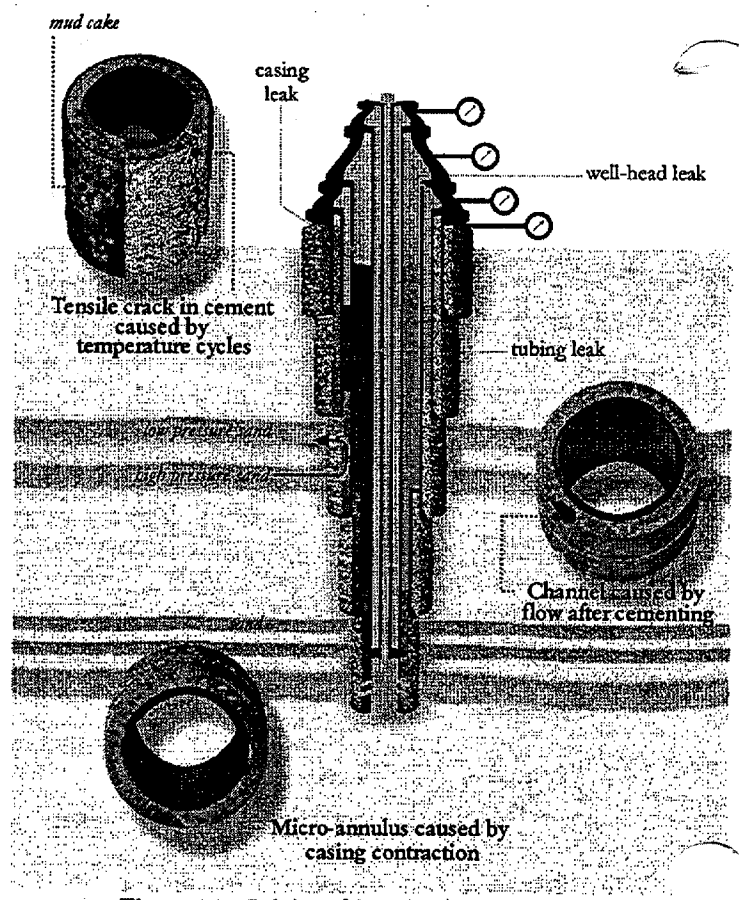

Figure 4.1: Origins of Sustained Casing Pressure

Tubing and Casing Leaks

A 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 back pressure form. Tubing and casing leaks are more often too small for identification from production data and pressure testing is often used. Past experience has shown that tubing leaks have the greatest potential for causing a significant problem.

CNG has developed a methodology for identifying the worst case casing pressure that can be expected for a given well. The technique attempts to determine the deeper zone providing the pressure support using the fist indication of surface pressure and historical density of the fluid left in the annulus. Using this method in the High Island area, a high pressure gas shale string was identified as the zone providing gas and pressure to the annulus.

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.

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. Portland cement is a brittle material and susceptible to cracking when exposed to thermally induced or pressure induced tensile loads. Experimental test results indicated that all cement systems tested exhibited one or more failure modes. 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 4.2**

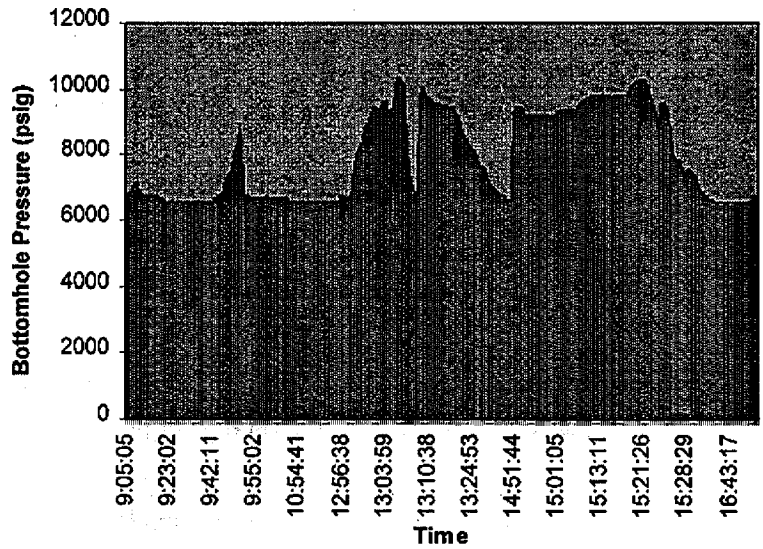

Figure 4.2: Typical Ship Shoal Frac Pack Treatment

This technique 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 in damage to the casing/cement bond by creating a small micro annulus when this high pressure is released. Chevron researchers (Jackson & Murphey, 1993) 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 4.3**).

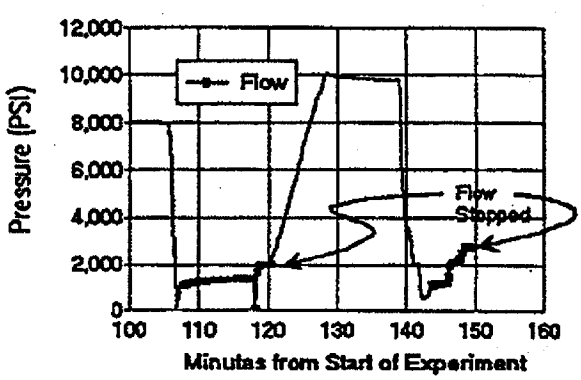

Figure 4.3: Flow through micro-annulus.

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

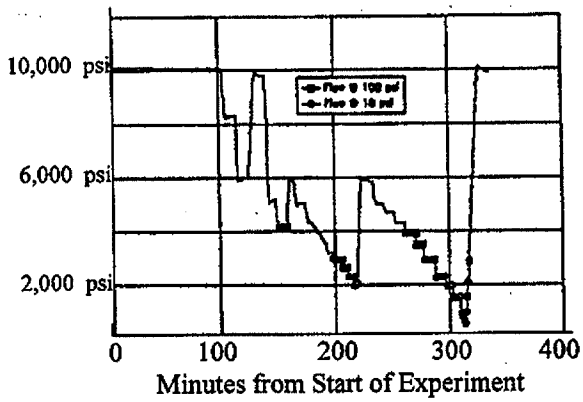

Figure 4.4: Effects of decreasing internal casing pressure.

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 4.4)**

Chapter 5

Prevention Methods

Much work has been done on improved cement formulations for reducing the occurrence of gas flow through cement behind casing.

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
2. Annular Casing Packer
3. Internal Pressure Considerations during Completion and Production

Cement Formulations

New cements are designed to prevent the occurrence of at least one of the mechanisms leading to flow after cementing. These mechanisms include the following:

- fluid loss,
- reduction of cement slurry volume, both bulk and internal, due to hydration reactions,
- development of porosity and permeability in cement as conduits for migrating fluids,
- development of gel strength and subsequent loss of hydrostatic pressure.

Compressible Cements

In the late seventies, it was found out that a rapid decrease in hydrostatic pressure exerted by a column of setting cement can be attributed to a volume reduction occurring in cement slurry. Due to very low compressibility of cement slurry, even a small volume loss results in a rapid pressure decrease. Pressure maintenance was thought to be improved if compressibility of cement slurry could be increased, Tinsley et al. (1979). An in-situ gas generating additive was developed and tested in the laboratory as a way of obtaining high compressibility. Results of lab testing were encouraging. An additive that would release hydrogen gas was chosen. It created some hazard problems since hydrogen is flammable and cases of hydrogen catching fire were reported. Also, there were problems with non-uniform distribution of the additive. Recently, this cement has been rarely used due to the controversy that the generated bubbles might coalesce downhole and promote gas flow rather than prevent it. Also, the amount of gas generated and its properties are hard to control. Moreover, at high pressures the gas will occupy little volume and its contribution to the overall compressibility increase may be insignificant.

Surface-Foamed Cement

Surface-foamed cements are obtained by the addition of a gas (often nitrogen) to a pre-mixed cement slurry before pumping the two-phase mixture downhole, de Rozieres and Ferriere (1991). They are especially useful for cementing of weak formations with low fracturing pressures. The foam is generated by adding a foaming agent (surfactant) that will lower the interfacial tension between the gaseous and liquid phases. Chemical properties of a foam cement will be essentially the same as of the base cement slurry. They are successful in preventing fluid migration because of their properties: they exhibit low fluid loss, they have low permeability and high compressibility. Contrary to the in-situ generated gas cements, they form a stable foam, i.e. the gas bubbles do not coalesce over the hydration period of the cement. Also, rheology of foam cement should be very beneficial in preventing fluid migration. Although there is a lack of direct experimental work on foamed cements, foams in general reveal high shear stress values at low shearing rates. Foam cements have been used recently in shallow cementing operations in the Gulf of Mexico due to the presence of weak formations in this region. One of the reasons for the growing number of cementing jobs run with foamed cement is that the quality of equipment used to generate foam has improved significantly over the last several years. The performance record of foam cements is very good. They can be used in a variety of conditions and they are recommended in most severe conditions for flow after cementing. They are, however, expensive, especially if cementing is performed offshore- up to ten times of a typical cementing job with neat cement. Also, they do not displace mud well due to their density and disadvantageous rheological properties at higher shear rates.

Thixotropic Cements

The mechanisms of action of thixotropic cements is a decrease of transition time. Transition time is defined here as the time elapsing between the end of cement placement and the time the cement reaches sufficient strength to resist fluid migration. Thixotropic cements were also thought to have increased resistance to deformations caused by migrating fluids, Stehle et al. (1985). These cements develop high early gel strengths by the addition of bentonite or polymers. Cementing job planning for a thixotropic system is not significantly different from planning for a conventional low-fluid-loss cement job. Every blend should be tested for thickening time and consistent concentrations of the additives should be maintained. Recently these cements have been used very rarely. Most formulations turn out to have high fluid losses. Also, contrary to the theory, transition time of these cements is not different from that of regular cements. Thixotropic cements undergo the same physical and chemical processes as neat cements. And the fact that they develop high early gels may actually promote early pressure loss. They were designed and field tested in the mid 80's. They are probably not used any more or used very rarely.

Expanding Cements

Expanding cements were designed to prevent the volumetric reduction occurring in setting cement as a result of hydration reactions and create a better bond at the cement/formation and cement/casing interface, Seidel and Greene (1985). They were especially intended to prevent the occurrence of a microannulus between the casing and cement. The expansion of this cement is achieved by the addition of anhydrous calcium sulphonate, calcium sulphonate lime or other additives. The use of these additives results in up to 0.2% volumetric expansion, however this

expansion occurs well after cement reaches an initial set. It should be noted that although these cements undergo a net bulk expansion, they also experience the same internal volume reduction as neat cements. They also exhibit a similar hydrostatic pressure decrease. Recent research also shows that although neat cements undergo a bulk volume reduction, it does not result in a generation of a microannulus, Bonett & Pafitis (1996). Expanding cements were designed in the mid 80's and field-tested then. Presently they are not used.

Right Angle Set Cement or Delayed Gel Cements

These cements have different names depending on their vendor, but their mechanism of action is essentially the same, Sepos and Cart (1985), Sykes and Logan (1987). They are designed to decrease transition time. But contrary to the thixotropic cement, they do not develop high early gel strength by thixotropy. Their SGS characteristics is shown schematically in Fig. 5.1.

SGS remains flat at the initial period of time. Then it starts to increase rapidly to achieve an early set. Depending on the length of the initial low-gel-strength period, these cements can be characterized as either accelerated: Right-Angle-Set cement or retarded: Delayed-Gel cement. These properties are achieved by the addition of various additives, like certain modified acrylamid polymers. Certain additives have a very good performance record; these cements usually exhibit good compressive strength characteristics; retarded cements are especially good for deep well cementing. Some problems have been, however, reported for these cements. They do not perform well in all conditions; some additives are very expensive; many polymers used are not stable in high temperatures; retarded cements usually exhibit high filtrate loss.

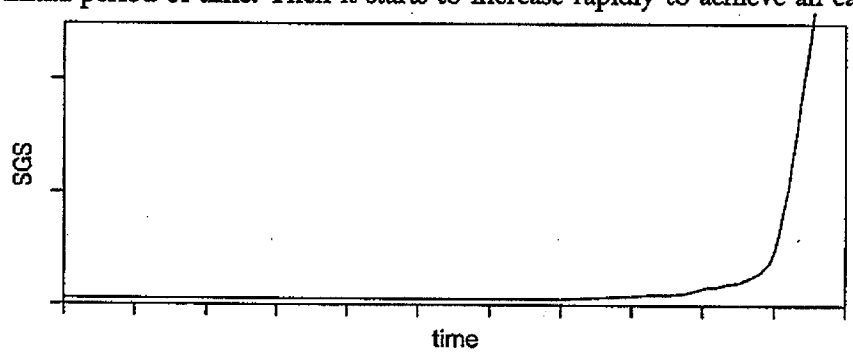

Fig. 5.1 Static Gel Strength development in a right-angle-cement, conceptual.

Impermeable Cements

Impermeable cements are designed to plug the pore spaces in the hydrating cement slurry and thus make it difficult for any fluid to flow through the matrix of the cement. This mechanism of flow is often referred to as micropercolation as opposed to fracturing of the weak body of cement slurry. It also provides with a means of controlling filtration and excessive loss of water. Cement permeability and porosity are reduced by a number of means. Certain polymers have been used successfully: latex, styrene-butadiene rubber and cationic polymers. Most polymers viscosify water and deposit an impermeable film on hydration products, Cheung and Beirute (1982). Microfine cements have been used recently. These are made of fly ash, silica fumes or blast furnace slag materials, Coker et

al. (1992). Salt saturated cements were reported to perform well, Lewis and Rang (1987). Salt precipitates as water is consumed in hydration, plugging pore throats.

Latex cements have been used widely and good results were reported, Ganguli (1991). Microfine cements have been used in deep water cementing recently. They perform well in low temperature, low density applications. Most other formulations have not been used much. Most impermeable cements demonstrate good rheological properties, low fluid loss and good bonding characteristics. Only salt cements are inexpensive. Other formulations tend to be very expensive and are not widely used.

Surfactant Cements

Surfactant cements are designed to trap migrating gas into stable foam as a result of the addition of a surface-active agent, Stewart and Schouten (1988). Stable foam exhibits high resistance to deformation at low shears and thus may contain the propagation of gas. This cement is not useful in preventing water flow. It was successfully tested both in the lab and in the field. Reportedly, it works well in moderate gas problems, but may not be as effective in cases of severe gas flow potential, Hibbeler et al. (1993). Surfactant cements are relatively inexpensive.

Emulsion Cements

Emulsion cement is designed to reduce cement porosity and permeability, decrease free water and trap gas or water in an emulsion Skalle & Sween (1991). It is obtained by forming of double emulsion: water in oil in water. Dry cement is added to the double emulsion. The developers of this cement claim that free water is eliminated by osmotic forces. Emulsion cement should exert high interfacial forces to migrating fluid. It will also have decreased permeability to water or gas by virtue of the presence of oil phase. This cement showed superior rheological properties and good bond strength as well as no free water in laboratory testing. It has not been used in the field yet. Potential problems that may arise if the cement is used in the field include the following :

1. high fluid loss,
2. difficult to prepare and handle,
3. emulsion may not be stable in high temperatures,
4. may be expensive.

In summary, it should be noted that although some cement formulations proved to be a good anti-migration solution in certain conditions, there is no special cement that would be effective every time in any conditions. Because of continued problem with gas flow behind casing and the high cost of the special cements, they are not used routinely.

Quality Control

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.

Application of annular back pressure

This technique was suggested by Levine et al. (1979) and field-tested by Cooke et al. (1982). The concept is simple. The decline of pressure exerted by cement column can be compensated for by the application of surface pressure by injecting water to the top of the sealed annulus. As mentioned above, a clear problem that must be overcome here is cement SGS buildup that may prevent transmission of pressure. Indeed, field measurements confirmed pressure of 60 psi applied ca. 10 hrs after pumping had been completed was not transmitted below the depth of 1900 ft below top of cement. However, earlier application of pressure in the order of 60-100 psi appeared to prevent the loss of hydrostatic pressure well up to 5 hrs after pumping had been completed up to the depth of 4500 ft below the top of the cement column. Approx. 15 hrs after pumping had been completed, an application of 500 psi broke the bond in the column down to 5400 ft (ca. 4400 ft below the top of the cement column) and caused a surge of more than 1000 psi in recorded downhole pressure. This experiment showed that SGS grows very rapidly in static columns of cement and indeed a high surface pressure would be necessary to break the gel and restore the pressure. Also, it showed that a rapid decline the restored pressure follows. It was clear that gel strength would rebuild very quickly and this technique turned out not to be effective.

Cement Vibration During Setting

The idea of vibrating the casing while and/or after cement is pumped is to minimize the cement transition time by fluidizing the slurry while being vibrated. Once vibration is ceased, the cement should set very quickly. A series of laboratory experiments conducted by Chow et al. (1988) which involved a cement sample subjected to an oscillatory deformations showed that an amplitude of ca. 0.001 in. was enough to minimize the elastic modulus of the slurry. The frequency of the oscillations was found to have relatively little effect on the value of the elastic modulus. The frequency was, however, in the range of 20 Hz. The laboratory procedure used simulated a concentric annulus. An electromagnetic driver capable of vibrating was attached to an inner pipe placed within a larger outer pipe.

The effects of driver frequency and amplitude on the pressure near the bottom of the annulus were recorded. It was found that after 90 min. of waiting an amplitude of 0.015 in. was enough to restore the pressure to its original value. Frequencies in the lower range of the instrument appeared to be more effective. A visual observation revealed that a thin layer of liquefied cement was created near the vibrated pipe, much like in the case of low rate pipe movement.

A field experiment utilizing a 200 ft long casing string was then carried out. Pressure transducers and accelerometers were attached to the casing and run. A geophysical truck capable of vibrating the casing was used. Vibration of the casing was successful in restoring hydrostatic pressure up to 230 min. when the response was getting very slow. The results of the experiment showed that a frequency of 8 Hz was optimal. A temperature rise signaling the end of the dormant period of the cement began at 150 min. There was a strong correlation observed between this time and the time when hydrostatic pressure of the cement began to drop significantly. It indicates that the pressure

loss in cement columns is affected mostly by hydration of cements. Cement slurry vibration has been shown to be an effective method of preventing the loss of hydrostatic pressure. It has not been used in the field since the tests. Apparently, all the heavy equipment needed to vibrate a long and heavy string of casing renders the method not feasible, even onshore.

Top Cement Pulsation

This method is an extension of the application of annular pressure at the top of the cement column. Instead of applying constant pressure, pressure pulses are applied to the top of the sealed annulus. The objective is to maintain the cement slurry in a fluid state so that hydrostatic pressure would not decline. Once the pulsations are ended, the slurry will develop a structure highly resistant to any deformation. This will minimize the slurry transition time. Another potential benefit from this technology is an improved Cement Bond Log (CBL), Haberman (1996). The equipment used to reciprocate the slurry is very simple and inexpensive.

The equipment used consists of an air/water compressor and a back pressure valve. Air or water is compressed and injected into the closed annulus within 5 seconds. When the pressure reaches 100 psi, the back pressure valve is opened and air/water is exhausted. The exhaust cycle takes about 5 seconds and the full cycle is about 10 seconds. During the compression cycle, the column of cement will travel downwards due to the compressibility of the cement slurry and expansion of the borehole as well as the compression of the casing. The contribution from the casing may be neglected due to the small pressure applied.

CBL logs for cemented wells where TCP was applied indicated consistently a better bond as compared with those where cement was set undisturbed. With this technique, the fluidity of the slurry is monitored by periodically measuring the volume of water or gas pumped into the annulus to increase the pressure to 100 psi. Compressibilities of the system obtained in such a way turned out to be 2 to 3 times greater than the compressibility of water for a given annulus. The change of compressibility due to cement setting determined by the observation of the volume of fluid pumped into the annulus. A relatively short thickening time most likely caused by slurry dehydration was noted as the cause of the rapid decline of the system compressibility. There are, however, other possible mechanisms: attenuation of the pressure wave by the thickening cement slurry, decline of cement compressibility due to its thickening and the cement slurry's inability to transmit horizontal stresses effectively due to its plasticity.

Low rate casing rotation and reciprocation

The reason for casing movement is to improve mud removal and to modify the cement transition time. The loss of pressure in the cement column is delayed by the movement. Once casing is not moved any more, cement starts to set very quickly and develops high resistance to deformation so that formation fluids do not have enough time to migrate upwards.

Laboratory tests done to develop the technique showed that slow movement of a pipe creates a thin water layer around it. Once movement is over, the layer heals very fast, so the cement can create a bond with the pipe. It is interesting to compare transition times of a slurry setting under static conditions and the same cement slurry setting while the pipe was moving slowly, after Sutton and

Ravi (1991). The latter transition time is much shorter. It was recommended that the casing be either rotated at the rate of 2-8 rpm, or reciprocated at 0.2- 2 ft/min depending on the size of the casing. That is, the authors found that the minimum rate to maintain liquidity was between 3 and 7 ft/min. for casing rotation and 1.7 ft/min for casing reciprocation. Also, it was found that the torque needed to rotate the casing was much less than torque calculated from SGS. The observed torque for casing rotation or load for casing reciprocation are within the allowable range for casing thread and hook load according to the authors. This technique, although sound in principle, has not been utilized much.

Deep Set Annular Packer

A deep set annular packer is being considered as a method of eliminating excess casing pressure in new wells. This technique(Vrooman et al., 1992) received one of the 1992 Petroleum Engineering International Meritorious Engineering Awards. Often, this technique eliminates gas and pressure migration to the surface in new wells. However, excess pressure can remain trapped under the packer and must be considered in the design.

These packers inflate when specific pressure differential is applied onto them. They seal the annulus and therefore prevent upward migration of fluids. These devices cannot be effective against soft formations. This limitation is severe for most areas in the Gulf of Mexico where shallow sediments are often poorly consolidated. They were reported to set prematurely and sometimes tend to get damaged while the casing they are attached to is run down the hole. According to some critics, as they are set, they stop transmitting any pressure from above them. Thus, if set deep they may trigger or accelerate fluid migration and further exacerbate the problem rather than prevent it. If they are set to shallow, they function much like closing a valve on the casing so that pressures cannot be measured.

Special Procedures for Deep Water Locations

The design and execution of a cementing job in an area with potential gas migration is different for shallow and deep water applications. Summarized in Table 5.1 below is a sequence of operations leading to successful cementing operations in shallow and deep water wells.

Table 5.2 summarizes present techniques and procedures used by some operators in the Gulf of Mexico.

Table 5.1. Technical requirements for anti-gas cementing

Operation/ Property	Shallow Water Cementing	Deep Water Cementing:
Mud Design	flat gel strength, low fluid loss, firm, thin filter cake	same as shallow water
Mud Conditioning	to eliminate gels and erode excessive filter cakes, Hartog et al. (1983)	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 versatility and high density flexibility
Spacer	pumped to separate mud from cement and to wet surface of rock and casing in case of oil base muds, Hartog et al. (1983)	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
Mud Displacement	turbulent flow regime if possible, minimum contact time 4 min., Marlow (1989)	usually plug flow
Casing Centralization, Reciprocation and Rotation	all achievable	centralization difficult to achieve, casing cannot be moved
Fluid Density Hierarchy	fluid pumped denser by 10% than fluid displaced	difficult to achieve due to narrow margin between pore pressure and frac gradient
Fluid Frictional Losses Hierarchy	fluid pumped having 20% more frictional losses than fluid displaced	achievable
Cement Free Water and Sedimentation	zero, Webster & Eikers (1979)	zero
Cement Filtration	less than 50 ml in API HTHP test, 1000 psi differential pressure, Cook & Cunningham (1976) Garcia & Clark (1976)	less than 50 ml in API HTHP test, 1000 psi differential pressure,
Thickening Time	cement should start to set from the bottom up immediately after placement, Marlow (1989)	same as shallow water
Transition Time	minimum	minimum(
Rheology	optimized so that frictional pressure losses follow the above hierarchy, ECD must not exceed fracturing gradient of the formation	difficult to achieve due to narrow margin between pore pressure and fracturing gradient
Compressive Strength	must be in the order of 500 psi in 24 hr at bottom hole conditions	difficult to achieve at low temperature and for low density cements typically used, must use special cements

Table5.2. Techniques and procedures to prevent flow after cementing in the Gulf of Mexico.

Operator:	Special cements used:	Other techniques/operations:
BP	• avoid using special cements on routine basis, • 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	• salt-saturated cements, • cement substitutes, • compressible cements, • surfactant cements, • slag mix cements.	• focus on good mud displacement.
Phillips	• cements: silica fume, colloidal silica.	
Mobil	• lightweight cements with guar, sugar or polymers to control free water.	
Arco	• latex expanding thixotropic cements	• good supervision of cementing job execution
Texaco	• 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	• right angle set cements, • latex cements, • foamed cements.	• low fluid loss, • zero settling, • proper supervision of job execution, • customized spacers and preflushes to maximize mud displacement.
Amoco	• gas migration test screening,	
Conoco	• cements with quick transition time,	• emphasis on fluid loss control. and avoidance of cement retardation

Production Operation Considerations

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.

Chapter 6

Diagnostic Methods

The output worksheets contain the imported tabular data from the simulation and display the results graphically in the form of x-y scatter plots.

The 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
2. Well logging
3. Monitoring fluid levels
4. Pressure testing
5. Bleed-down performance
6. Wellhead maintenance

Flow Testing and Sampling

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. Sampling of the hydrocarbons is often done to try to match identifying characteristics of the hydrocarbons with those of a known producing formation. It is often possible to determine if the source of gas is deep or of biogenic origin through detailed gas composition and isomer analysis.

Well Log Analysis

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.

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.

Wellhead and Tubular 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.

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.

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 about 2000 psi. In this case, periodic application of grease to the wellhead seals eliminated the problem.

Chapter 7

Remediation Efforts

Tubing leaks, which are the most dangerous cause of SCP, are easily repaired by means of a well workover. However, remediation of flow through channels and cracks in cemented annuli have proven to be extremely difficult.

Operators are investigating three primary methods for remediation of excessive casing pressures: 1) periodic bleeding of excessive pressure; 2) partial bleeding followed by lubricating in a higher density fluid; and, 3) installation of a string to allow shallow annular circulation. Several operators are collecting detailed data on the pressure behavior of wells that have undergone periodic bleeding. Several example case histories are summarized in this chapter. The procedure of periodic bleeding of casing pressure is perceived by some operators to worsen the sustained level of pressure. In some cases however, bleeding of SCP has been shown to reduce the severity of the problem.

CNG 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.

Shell has also used this procedure in several wells. Engineers at CNG and Shell are obtaining the necessary permissions to allow Dr. Scott to document this procedure on-site. Amerada-Hess has tried this same approach using mud instead of weighted brines. 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 designs.

In addition to the three primary methods, several alternate methods have also been developed in an attempt to eliminate or reduce the pressure once a sustained casing pressure is observed. The following methods will be discussed in more detail in this chapter:

1. Do Not Bleed-Off Pressure.
2. Bleed-Off Pressure.
3. Lubricate in Weighted Brine.
4. Circulation of Weighted Brine or Mud.
5. Inject Sealing Fluid.

6. Squeezing.
7. Casing Leak Repair.

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 increase the influx of gas or light weight fluids into the annulus unless equal weight fluids are replaced. Many are in favor of changing the current MMS policy which require that excess casing pressure be bled to zero in order to obtain a sustained casing pressure waiver. Bleeding to a pressure greater than atmospheric is also preferred by some operators.

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

Case History 1

Case history 1 is an example for which periodic bleeding was successfully used to reduce the pressure on an intermediate string and continuous venting was used successfully to reduce the pressure on the conductor casing. The well schematic is shown in **Figure 7.1.** The point of gas entry into the casing annulus was established by temperature and noise logs to be the top of the 7-in. liner. The leak path to the surface is through a cemented annulus between the 7-in. production casing and the 9.625-in. intermediate casing. Cement was circulated all the way back to the surface.

This well was drilled and cased with one rig and then later completed. A sustained casing pressure of 4400 psi

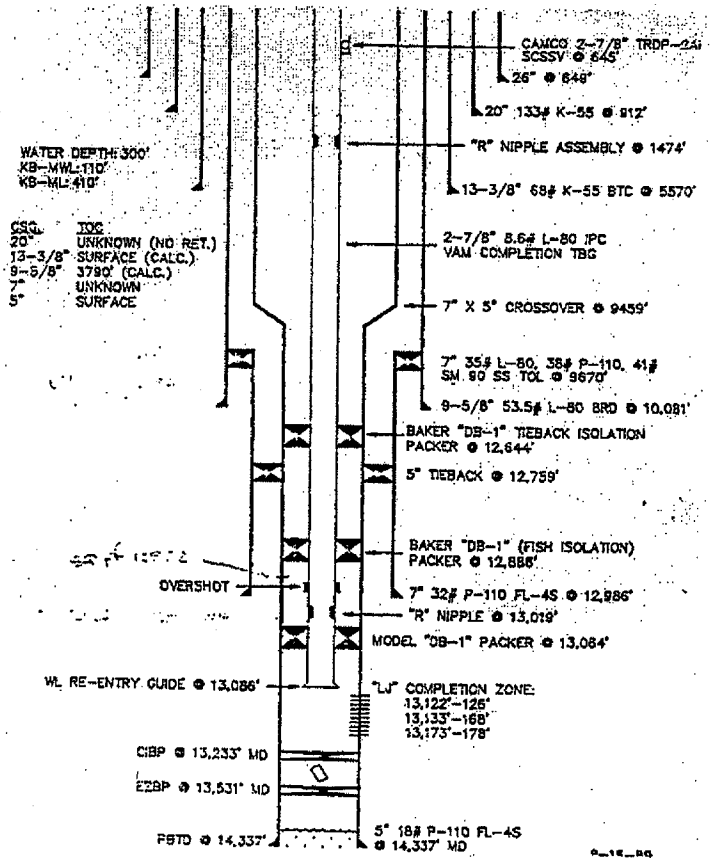

Figure7.1: Wellbore Schematic for Case History 1.

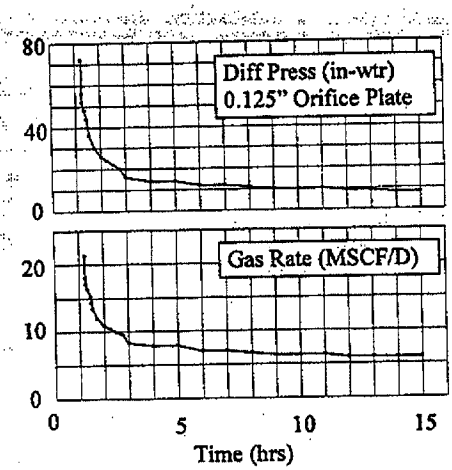

Figure 7. 2: Leak Rate measurement for Case History 1

developed on the 9.625-in. intermediate casing before the completion rig was moved onto the well. The pressure could be bleed to zero through a half-in. needle valve in less than a 24 hour period. Essentially dry gas was bleed from the well. Shown in

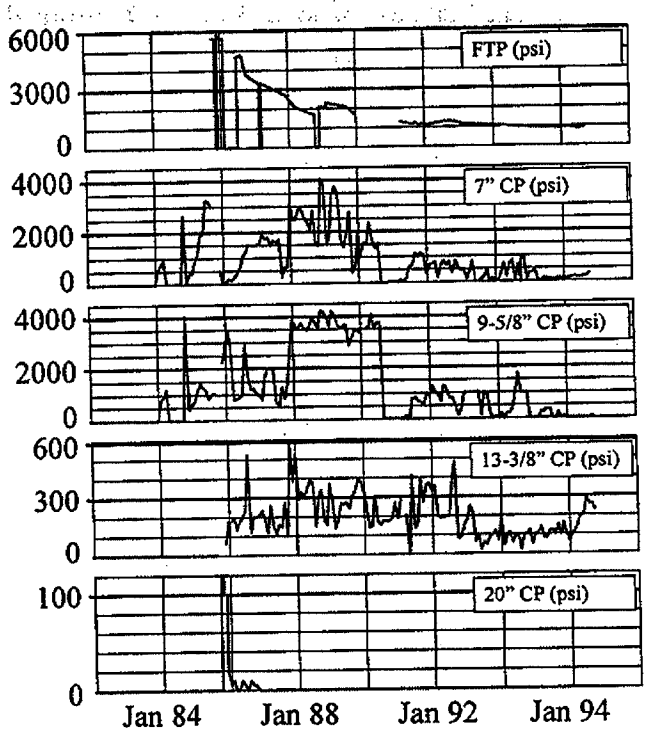

Figure 7.3: Pressure summary for Case History 1

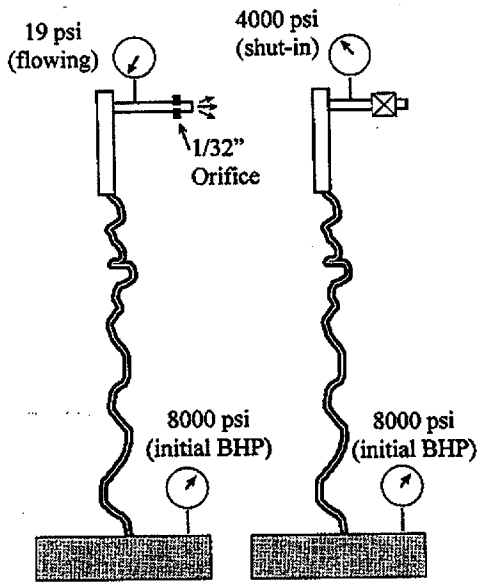

Figure 7. 4: Flow Behavior for Case History 1

Figure 7.2 is the result of a rate test conducted with a 0.125-in. orifice plate. The leak rate through the cement column would stabilize at about 5 MCF/D after about 12 hours of continuous bleeding.

The SCP history of this well is shown in Figure 7.3.The pressure on the 9.625-in. casing was kept low from 1984-88 by frequent periodic bleeding. During the next two years, only a small amount of bleeding was done when diagnostic information was needed. Field instructions were not to bleed without MMS approval. During the third quarter of 1990, the pressure was bled to zero and only low values of SCF were noted for about a year. The SCP increased again after this period but has stayed below 1000 psi. It is suspected that the path through the cement is plugging intermittently. A hypothetical flow path for this case is illustrated in Figure 7.4. One would anticipate difficulty keeping such a flow path open even if this was desired.

The leak rate of about 5 MCF/D measured for the Example Case 1 is a very low rate and would not pose any significant danger on an offshore production platform. This leak rate is on the order of supply gas releases on control systems and pilot lights on other production equipment. Shown in Figure 7.5 is a photograph of a flame being fed by a leak of about this rate. One would have difficulty boiling crawfish with such a low gas rate.

Figure 7.5 : Diverter Exit Flare for 19 psi flowing pressure differential.

Note in Figure 7.3 that this well also had sustained casing pressure on the production casing, the surface casing, and the conductor casing. Eventually it was determined that the pressure on the production casing was due to a wellhead leak. The pressure on the surface casing and conductor casing was

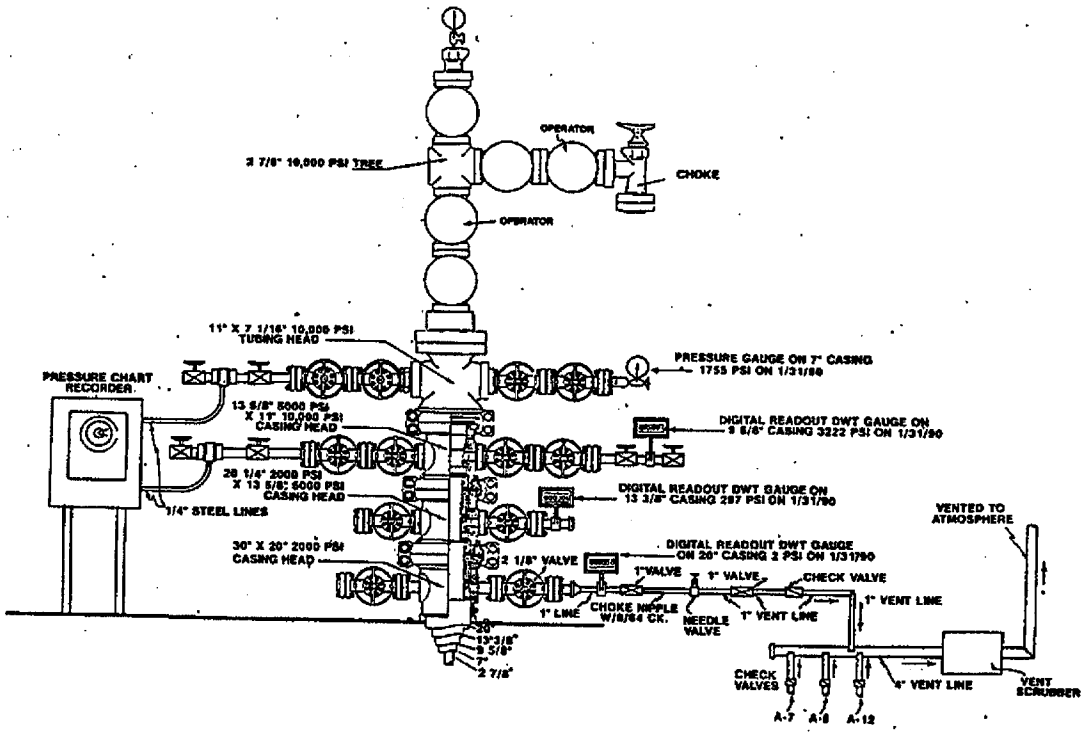

Figure 7.6: Schematic of casing venting system for Case History 1.

thought to be related to an incident of flow through cement while cementing the surface casing of another well on the platform. This resulted in a shallow sand being pressurized. In order to eliminate the pressure on the conductor casing, it was connected to a continuos venting system

(Figure 7.6). Once the venting system was put into service, the 20-in casing no longer registered pressure when gas samples were taken.

Lubricate in Weighted Brine or Mud

Several Gulf Coast operators have tried this 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 zinc bromide. It is hoped that the hydrostatic pressure in the annulus can gradually be increased using this technique. A pressure "stair-step" procedure that entails bleeding small amounts of light weight gas and fluid from the annulus and lubricating in zinc bromide brine is involved. Several operators have reported some reduction in surface casing pressures from the method. However, it has been observed that pressures can also increase while applying this method. It has been hypothesized that this occurs when a new "gas bubble" migrates to the surface. After trying this method for several years in several wells, the results have not been as promising as first indicated.

Other operators have injected mud instead of brine in an attempt to increase the hydrostatic pressure in the casing annulus. It was hoped that the solids in the mud could enhance plugging of the fractures in the cement. Mud also has the advantage of being less corrosive and less toxic, but is more difficult to inject because of the large concentration of solids in the fluid.

Case History 2

This case history is an example of injecting mud into the annulus in an attempt to reduce or eliminate SCP. Figure 7.7 is a schematic of Well A which had a SCP of about 1000 psi on the intermediate (10 3/4-in) casing. Mud with a density of about 15 ppg was injected into the intermediate casing on a daily basis for about 3 -1/2 months. The procedure used was to first record the initial casing pressure (which ranged between 700 & 900 psi) and then to slowly bleed the casing pressure off. After the bled off pressure was recorded heavy mud would be pumped into the annulus until the casing pressure was within about 200 psi of the initial casing pressure. The amount of mud pumped and the amount of mud bled were also recorded so that the net amount of mud being introduced into the casing could be measured. Figure 7.8 summarizes the observations which were taken over a 7 month period. After initially pumping about 15,000 lbs of mud into the intermediate casing over a 2 month period, the SCP had not been reduced by a noticeable amount. After this 2 month period, the annulus quit taking mud and a higher pump pressure was used in an attempt to inject more mud. Over a 1 month period the pressure was slowly increased until the annulus began taking mud. As shown in Figure 7.8, the breakover point corresponds to the an increase the production casing pressure indicating the creation of a new leak path from the intermediate casing into the production casing.

After this point there is a slight reduction in the intermediate casing pressure, but the creation of the new leak path confuses the analysis as to weather or not the mud the mud injection technique was the cause.

Figure 7.10 is a schematic of Well B on the same platform. Both the surface casing and the intermediate casings had SCP (see figure 7.11) and mud injection was attempted on both annuli.

After about 2 months the surface casing showed a marked and sustained decrease from 400 psi to about 180 psi. The intermediate casing pressure was also reduced by about 250 psi, but began building within a month and within 4 months even exceeded the initial SCP of 700 psi by 300 psi.

The benefits of the brine and mud injection techniques are not clear and do not appear to have long term effects. Also, the risk of creating more problems than already exist is substantial.

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. A new system has been developed that is commercially available and several operators are trying this system in wells that are not cemented to surface. A small diameter flexible tubing is inserted into the annulus to allow circulation to some depth. The tubing can go through the 90 degrees turn from the wing valve into the annulus. 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 could increase the ability to displace lighter weight fluids from the annulus and replace them with a weighted brine or mud.

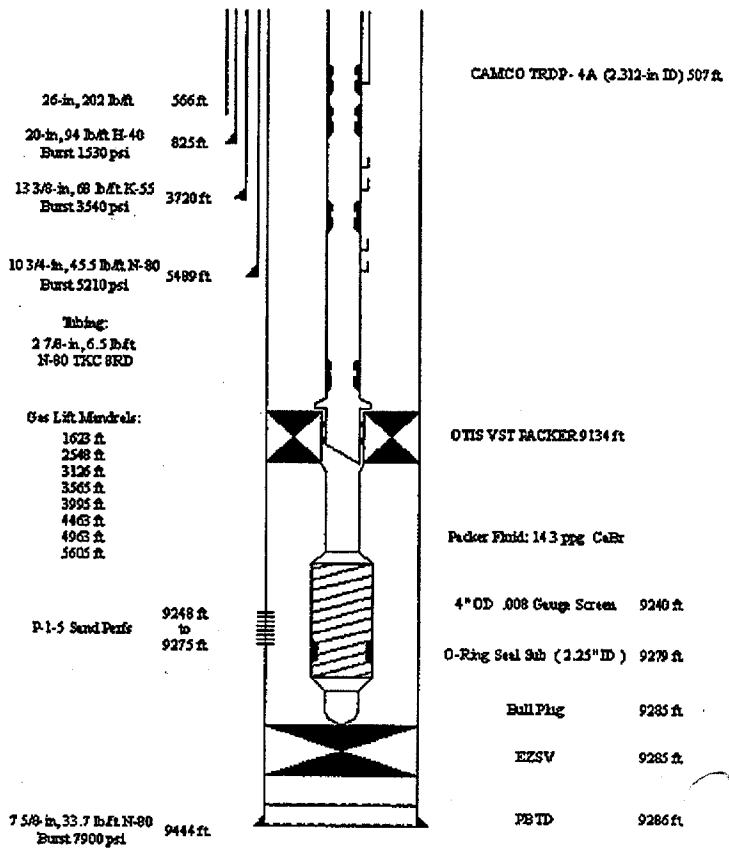

Figure 7.7 Case History 2, Well A

DATE	INTERMEDIATE CASING							
	INITIAL PRESS	PRESS AFTER BLEEDING	PRESS AFTER PUMPING	MATERIAL PUMPED	DENSITY OF PUMPED MATERIAL	LBS MUD BLED OFF	LBS MUD PUMPED	MUD WT. DIFF.
	(psi)	(psi)	(psi)		(ppg)	0	0	0
3/24/96	980	100	500	MUD	15.0#	51	630	579
3/25/96	690	70	500	MUD	15.0#	184	630	446
3/26/96	700	100	500	MUD	15.0#	176	473	297
3/27/96	770	160	500	MUD	14.9#	273	313	40
3/28/96	680	140	500	MUD	14.8#	288	466	178
3/29/96	670	100	780	MUD	14.8#	312	1,243	931
3/30/96	820	140	760	MUD	14.8#	363	466	103
3/31/96	860	100	770	MUD	14.9#	345	782	437
4/1/96	880	140	750	MUD	18.8#	342	790	448
4/2/96	870	130	750	MUD	18.9#	354	397	43
4/3/96	870	90	750	MUD	18.9#	372	595	223
4/4/96	830	150	770	MUD	18.9#	387	595	208
4/5/96	850	90	700	MUD	18.9#	417	595	178
4/6/96	900	100	800	MUD	18.9#	420	595	175
4/7/96	850	100	800	MUD	18.9#	453	595	142
4/8/96	900	100	780	MUD	18.5#	462	971	509
4/9/96	850	60	770	MUD	18.5#	468	777	309
4/10/96	870	60	780	MUD	18.8#	444	790	346
4/11/96	930	120	730	MUD	18.5#	414	389	-25
4/12/96	900	190	780	MUD	18.4#	456	386	-70
4/13/96	860	260	740	MUD	18.4#	426	386	-40
4/14/96	920	130	750	MUD	18.2#	432	382	-50
4/15/96	860	120	800	MUD	18.3#	423	961	538
4/16/96	830	90	780	MUD	18.3#	432	769	337
4/17/96	780	80	760	MUD	19.2#	418	806	388
4/18/96	860	80	780	MUD	19.2#	516	806	290
4/19/96	900	80	780	MUD	19.2#	504	806	302

Figure 7.8 Example data sheet for Case history 2

Well Workover and Squeeze or Injection Operations

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.

Cutting the casing and squeezing cement is normally considered as a last resort effort. This is due 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.

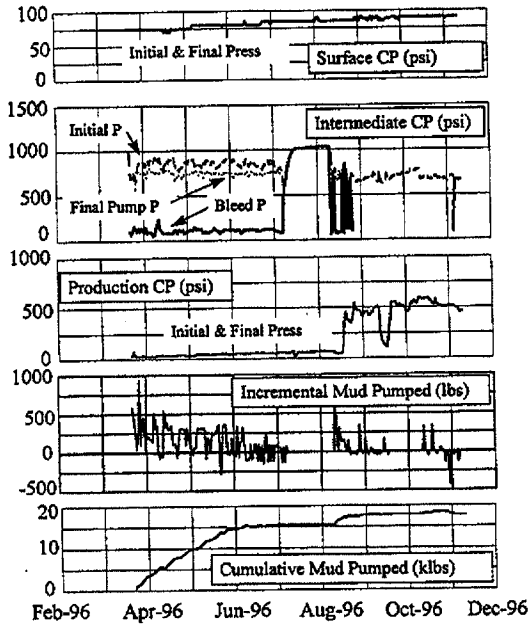

Figure 7.9 Pressure and injection summary for Case History 2, Well A

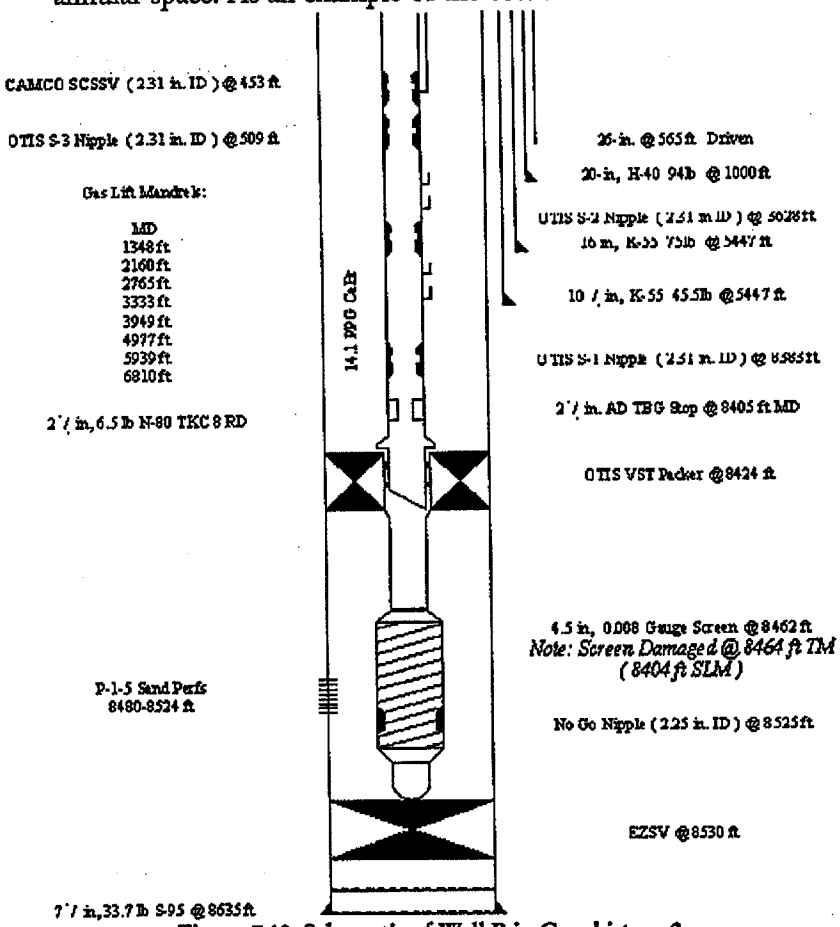

Figure 7.10: Schematic of Well B in Case history 2

Annular Intervention

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.

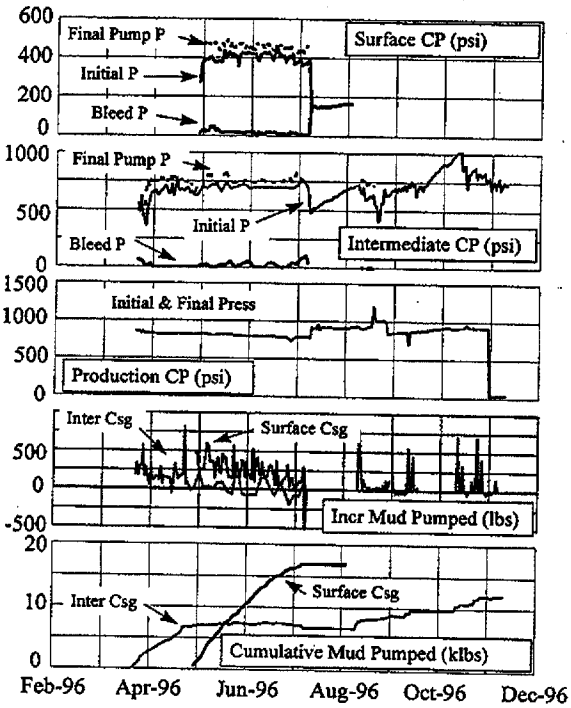

Figure 7.11: Pressure and Injection summary for Case history 2, Well B.

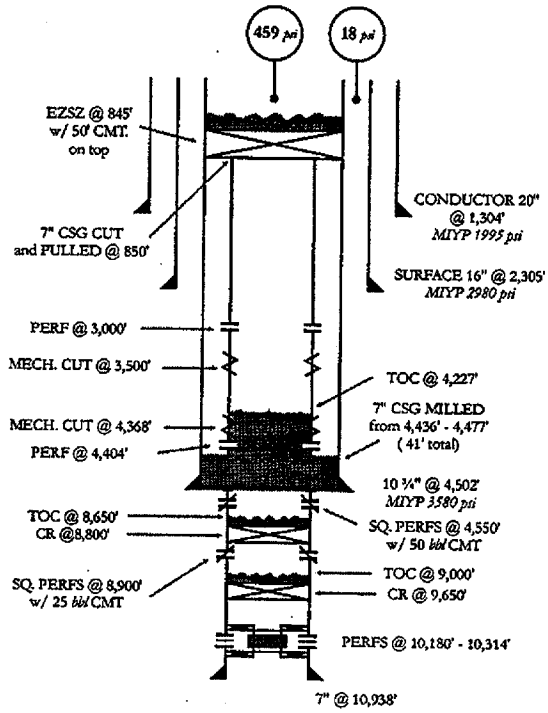

Figure 7.12: Example 1 of SCP after Squeeze Cementing

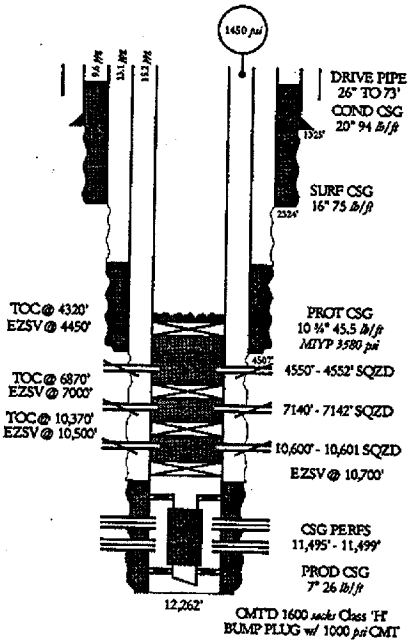

Figure 7.13: Example 2 of SCP after Squeeze Cementing

Chapter 8

Conclusions

Operator experience on the OCS has shown that Sustained Casing Pressure (SCP) problems can lead to blowouts of sufficient flow rate to jeopardize a production platform. However, there has been only minor pollution and no known injuries or fatalities due to problems related to SCP. This study has indicated that further substantial reductions in the regulatory efforts to manage the SCP problem on the OCS are possible without sufficiently increasing the risk of injury to offshore personnel or the risk of pollution.

Industry experience with problems resulting from sustained casing pressure has shown that the most serious problems have resulted from tubing leaks. When the resulting pressure on the production casing causes a failure of the production casing, the outcome can be catastrophic. The outer casing strings are generally weaker than the production casing and will also fail, resulting in an underground blowout. Flow rates through the tubing leak can quickly escalate if any produced sand is present in the flow stream. Blowouts of sufficient flow rate to jeopardize the production platform are possible.

- About 50 % of wells with sustained casing pressure have pressure on the production casing.
- The cause of pressure on production casing is generally easier to diagnose than pressure on one of the outer casing strings.
- Pressure on production casing is generally easier to correct than pressure on the outer strings.
- The magnitude of the leak rate is as important as the magnitude of the pressure when determining the potential hazard posed by sustained casing pressure.
- Portland cement is a brittle material and susceptible to cracking when exposed to thermally induced or pressure induced tensile loads. Experimental test results indicated that all cement systems tested exhibited one or more failure modes.
- About 10 % of the casing strings exhibiting sustained casing pressure are *intermediate* casing strings.
- About 30 % of the casing strings exhibiting sustained casing pressure are *surface* casing strings.
- About 10 % of the casing strings exhibiting sustained casing pressure are *conductor* casing strings.

- Only about one-third of the casing strings exhibiting sustained casing pressure are in wells that are active and producing.
- None of the remedial procedures to stop flow through cement outside of casing have been shown to be effective.
- About 90 % of sustained casing pressures observed are less than 1000 psi in magnitude.
- More than 90% of all sustained casing pressures observed are less than 30 % of the minimum internal yield pressure (burst pressure) of the casing involved.
- The regulatory burden associated with managing the sustained casing pressure problem on the OCS was significantly reduced by a series of LTL's issued since 1991.
- Further substantial reductions in the regulatory efforts to manage the sustained casing pressure (SCP) problem on the outer continental shelf (OCS) are possible without significantly increasing the risk of injury to offshore personnel or the risk of pollution.

Chapter 9

Recommendations and Future Research Needs

Additional research is needed to develop improved diagnostic test procedures for wells with SCP and to better define the potential increase in SCP that could be caused by sustained bleeding through a small diameter bleeding nipple for various well situations.

Regulations concerning the management of SCP should be refined to better reflect the well conditions present. The regulatory burden associated with the management of SCP should be changed to better reflect the severity of the hazards involved. It is recommended that the following regulatory changes be considered.

1. Wells with SCP be redefined to include only wells with one or more casing strings having a pressure in excess of 100 psig.
2. For wells having SCP only on the production casing, departures be automatically given ("self-approved") if:
   - the SCP is less than 30% of the minimum internal yield pressure of the casing, and
   - the instantaneous leak rate does not exceed 5 MCF/D of gas when the pressure is reduced by 50% or more by bleeding through a half inch needle valve during a test that does not exceed 24 hours in duration, and
   - no more than one barrel of non-hydrocarbon liquid is recovered during the test.
3. For wells having SCP on the intermediate casing, surface casing, or conductor casing but not on the production casing, and the leak path is through a cemented annulus of more than 1000 ft in length, then the operator should be given the option of venting the casings having SCP to the production system or a flare stack as long as the flow rates are metered and the flow rate does not exceed 10 MCF/D of gas and 1 bbl/d of liquid. Venting should be conducted through a choke of no more than 1/8th inch in diameter and the well should be shut-in at least once a month to determine the SCP after a 24 hour shut-in. Venting should be stopped if the SCP upon shut-in increases more than 20 percent of its initial value.
4. For wells with SCP on the production casing, additional underground blowout diagnostic tests should be conducted if the gas leak rate is found to exceed 10 MCF/D. The additional diagnostics could include fluid level determinations, noise logs, and temperature logs conducted with the well shut-in. If a tubing leak is suspected, the tubing should be repaired.

5. For wells with SCP on the production casing that suddenly develop SCP on the intermediate casing, additional underground blowout diagnostic tests should be conducted.

It is also recommended that additional research is conducted with the goal of reducing tubing leaks and improving the long term sealablility of cemented annuli. Specifically it is recommended that:

1. Additional research be conducted to determine if the occurrence of SCP in the production casing can be correlated with the type of tubing connectors used.
2. Additional research be conducted to develop improved diagnostic test procedures for wells with SCP and to better define the potential increase in SCP that could be caused by sustained bleeding through a small diameter bleeding nipple for various well situations.

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Worldclass People, Systems & Services

Development of a Casing Annulus Remediation System (CARS)

Noel A. Monjure

ROTAC/MMS Meeting

April 1, 1998

LSU, Baton Rouge, La

Worldclass People, Systems & Services

Development of a Casing Annulus Remediation System - Background

- Shell Offshore has been experiencing sustained casing pressure (SCP) in the South Timbalier area for at least five years
- Current method of trying to regain hydraulic control (bleed and lubricate) proved expensive, time consuming, and yielded limited results
- A possible solution was jointly conceived and developed to utilize traditional displacement hydraulics to reduce the time to regain pressure control to a few days.
- This new method has been designated the "CARS" Casing Annulus Remediation System (patent pending)

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Development of a Casing Annulus Remediation System - Challenges

Worldclass People, Systems & Services

- *How do we insert a fluid delivery system through an existing wellhead assembly,*
- *Into a constricted and pressurized annulus,*
- *Transport it far enough downhole to achieve the needed hydrostatic column for pressure control,*
- *Deliver a suitable fluid to establish permanent hydraulic control, and*
- *Provide a simple method of renewal if necessary*

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Development of a Casing Annulus Remediation System - System Overview

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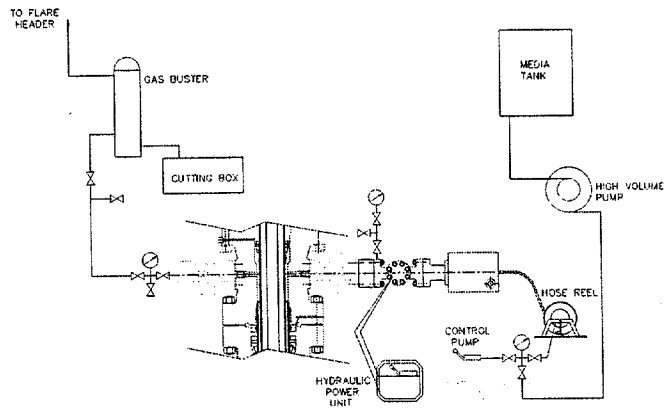

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Development of a Casing Annulus Remediation System - Procedure

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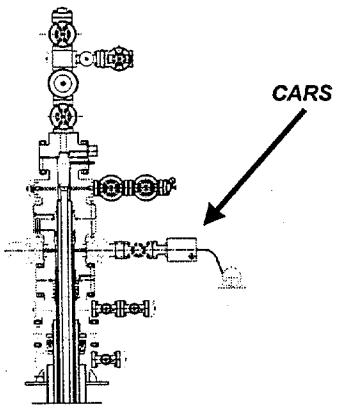
- Connect one annulus outlet to test facilities & bleed down
- Install VR plug in opposite annulus and install shearing valve
- Rig up CARS packoff, driver, and pumping system
- Run in hole until desired depth is achieved
- Displace annular volume with selected fluid
- Bleed off all lines and verify pressure is reduced to zero
- Disconnect CARS system and install terminal fitting
- Rig down and secure well



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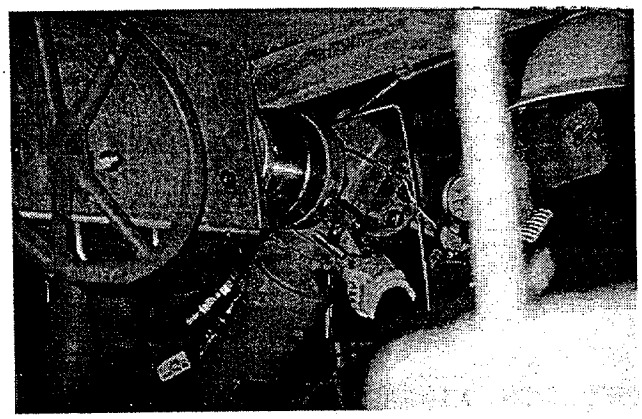
CARS System
CARS Pressure Containment Assembly

Worldclass People, Systems & Services



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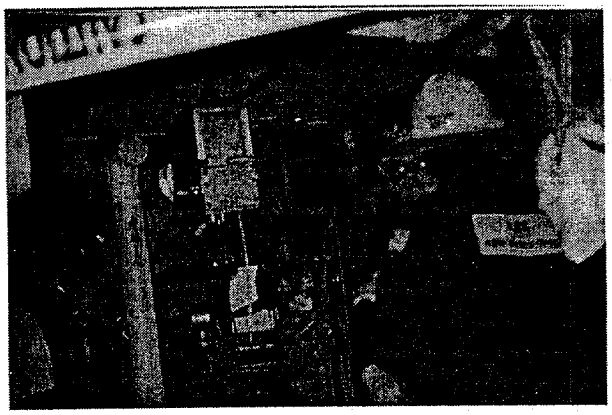
CARS System
Power Injection of Flexible Hose

Worldclass People, Systems & Services



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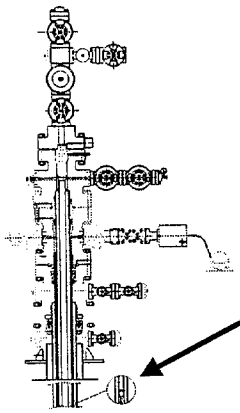
Development of a Casing Annulus Remediation System - System Overview

Worldclass People, Systems & Services



CARS nozzle shown in casing annulus

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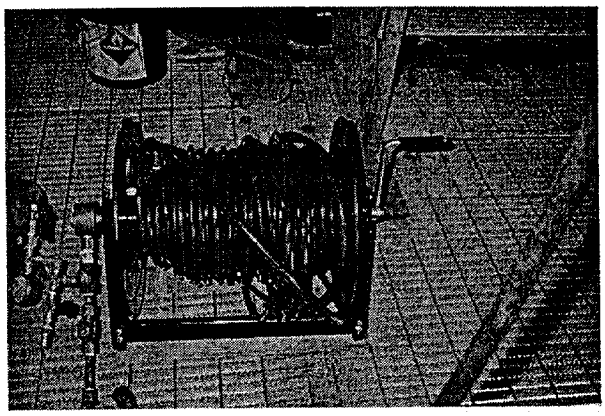
Development of a Casing Annulus Remediation System - System Overview

Worldclass People, Systems & Services



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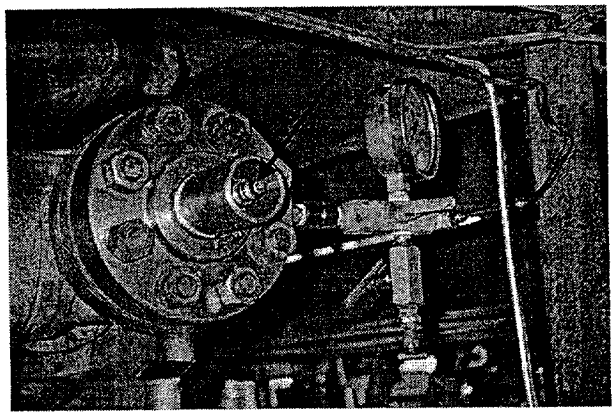
Development of a Casing Annulus Remediation System - System Overview

Worldclass People, Systems & Services



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Development of a Casing Annulus Remediation System - Lab Testing

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- ✓ Verify flexible tubing can be inserted into annulus - complete
- ✓ Verify low pressure seal on hose OD - complete
- ✓ Verify "burst" pressure of Teflon plugs - complete (650 psi)
- ✓ Verify high pressure seal on hose OD (1000 psi) - June 20,1997
- ✓ Final burst plug test (witnessed) - June 20, 1997
- ✓ Field Operating Procedure - July 11, 1997
- ✓ System integration testing - July 14-18, 1997
- ✓ Integration test & procedural review - July 20-25, 1997
- ✓ Field trials at South Timbalier - September, 1997

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Development of a Casing Annulus Remediation System - Case Histories

- South Timbalier Block 300, Well No. A- 15
  - Rig up CARS system, test same, bleed casing pressure to zero, run in annulus to 400 ft..
- South Timbalier Block 300, Well No. A- 25
  - Rig up CARS system, test same, bleed casing pressure to zero, run in annulus to 103 ft.. ; encountered unknown restriction; attempted to pull back & re-inject several times; final position 97 ft.

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Development of a Casing Annulus Remediation System - Case Histories

Worldclass People, Systems & Services

- *South Timbalier Block 300, Well No. A - 22*
  - Rig up CARS system, test same, bleed casing pressure to zero, run in annulus to 350 ft.. & displace annulus w/ 19.2 ppg zinc bromide.
- *South Timbalier Block 300, Well No. A- 7*
  - Rig up CARS system, test same, bleed casing pressure to zero, run in annulus to 696 ft. & displace annulus w/ 19.2 ppg zinc bromide; install terminal fitting.

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Development of a Casing Annulus Remediation System - Future Actions

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- *Nine additional wells have been identified for phase two of the South Timbalier pilot project*
- *Design modifications have been completed and function tested*
- *Four additional service technicians have been selected for training in CARS applications*
- *One additional CARS system is planned for July 1998*
- *Design work is under way for pressures greater than 2,000 psi*

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Development of a Casing Annulus Remediation System - Conclusions

- *The CARS system has met the initial objectives for inserting a flexible displacement system into an existing casing annulus*
- *Preliminary field results have met with some success, but improvement is a key factor in phase two*
- *CARS has succeeded in placing the point of displacement at sufficient depths for first step remediation of SCP up to 700 psi.*

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Sustained Casing Pressure on Producing Wells

April 1, 1998

MMS ROTAC Meeting

Objectives

- Highlight current MMS regulations and policy relating to SCP
- Nature and extent of the problem
- Trends
- Future efforts and needs

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

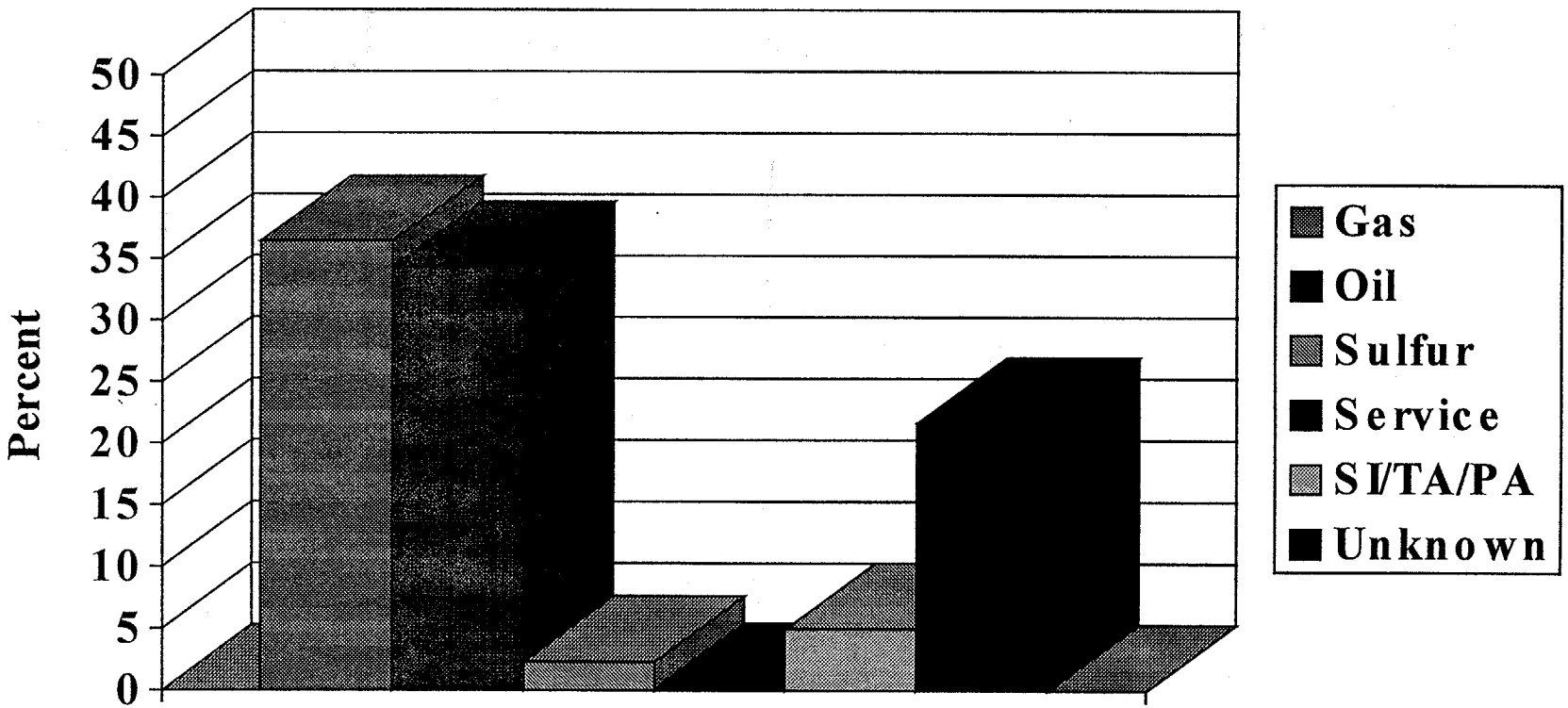
Departure Processing

- TAOS Section (Field Operations)
  - » 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

SCP Data - GOM OCS

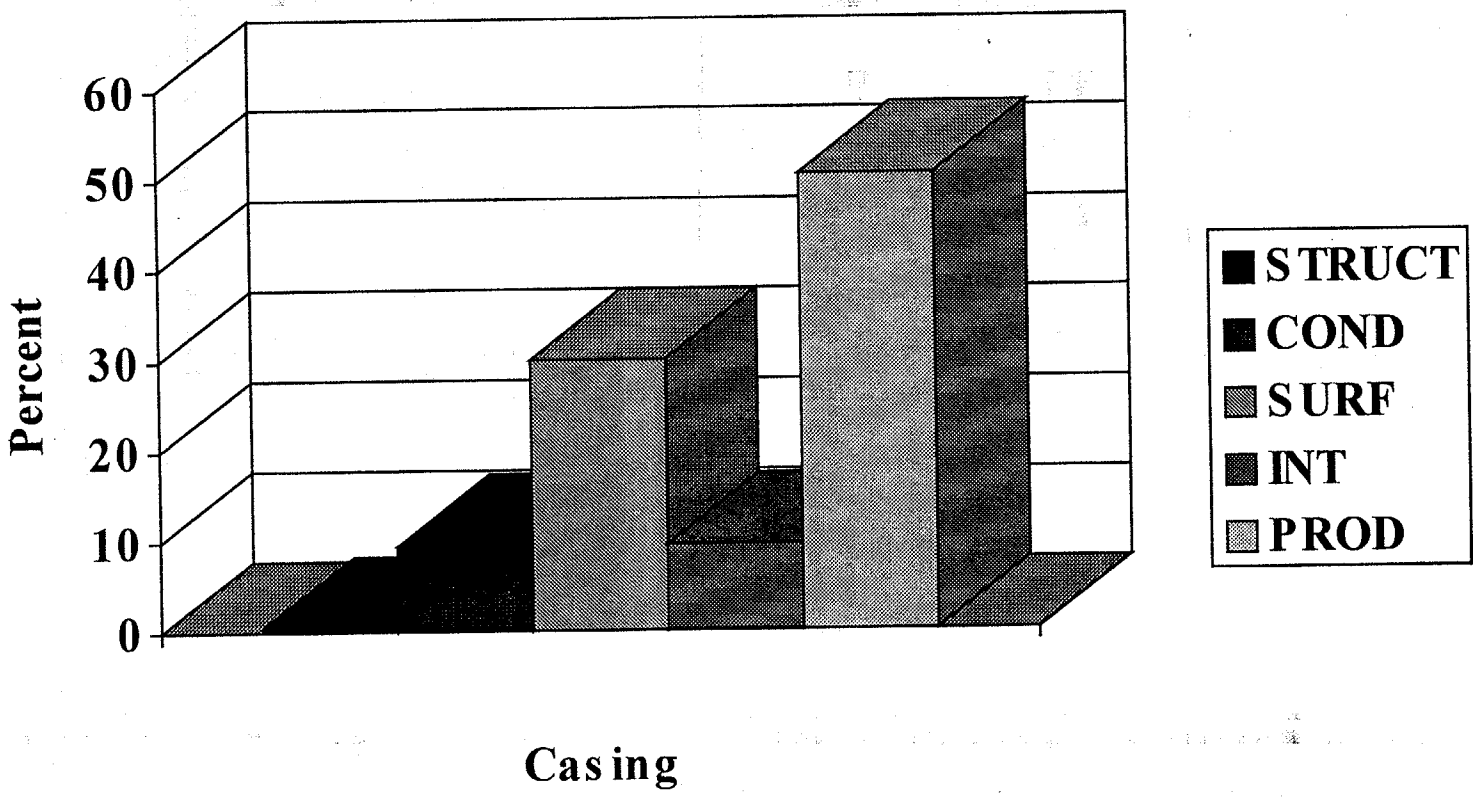
- 8,100 wells; affecting 11,500 csgs (12/95)
  - » 15,000 wells (POW, PGW, OSI, GSI)
- *Offshore* - January 1998
  - – "Preplanning well abandonment..."
  - » 25% of remaining wells in GOM have SCP
- Trends
  - » incomplete information; "it's thermal"

SCP Data - By Well



all casings represented

SCP - By Casing Type



MMS - Next Step?

- Policy
  - » Revise NTL
  - » Production Risers for Floating Systems
  - » Nonproductive wells
- Continue/expand remedial projects
- Subsea wells
- Related efforts
  - » Tubing Design; Gas Migration studies

LSU - *Excessive Csg Pressure on Producing Wells*

- Recommendations:

Dry Tree Tie-back Systems

- Riser Policy - single vs. dual bore
- MMS
  - » zero tolerance - outer riser annulus
  - » no "self approved" category
  - » continuous monitoring; bleed to zero in 4 hrs
  - » 6-month rediagnostic
- OOC effort ongoing
  - » build-up rate criteria; risk-based approach

Questions/Discussion

Overview of LSU / MMS Research Program on Well Control

By
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Louisiana State University
Baton Rouge, LA 70803
April 1, 1998

Research Theme

Development of Improved Procedures for Detecting and Handling Underground Blowouts in a Marine Environment.

Main Areas of Research

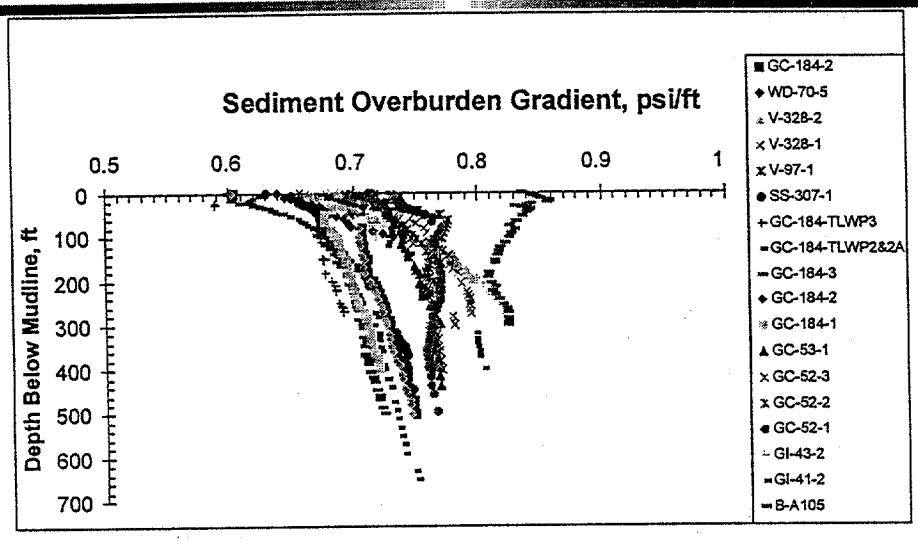
- Prevention
- Detection
- Remediation
- Post-Analysis and Training

Task1- Density, Strength, and Fracture Gradients for Upper Marine Sediments.

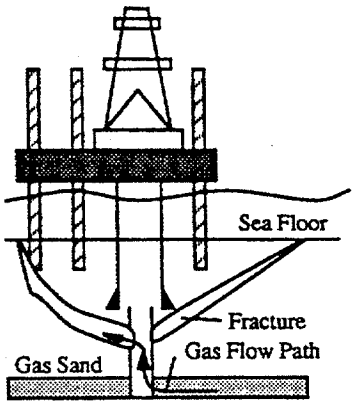
- 1A- Leak-off Test and Sediment Density Database for Upper Marine Sediments.
- 1B- Leak-off Test Practice for Upper Marine Sediments.
- Frac Pressure = 0.45(Water Depth) + 0.80(Casing Penetration)

  1C-Internet Database with GIS System.
- 1D- Computer Model for LOT

Example Density Variations in UMS



Shut-in Kick Broaching to Surface



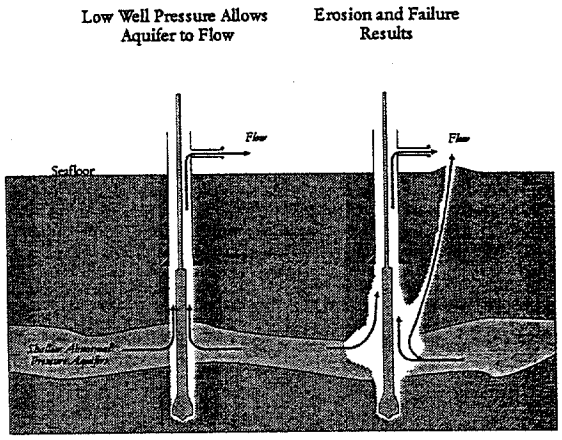
Diverting Shallow Kicks

- Diverting a kick is an attempt to prevent a blowout from broaching to the surface and undermining a surface supported rig.
- Conditions which favor diverting:
  - Weak casing shoe AND
  - High probability of broaching AND
  - Impermeable (Clay/Shale) fomations AND
  - Surface supported rig.

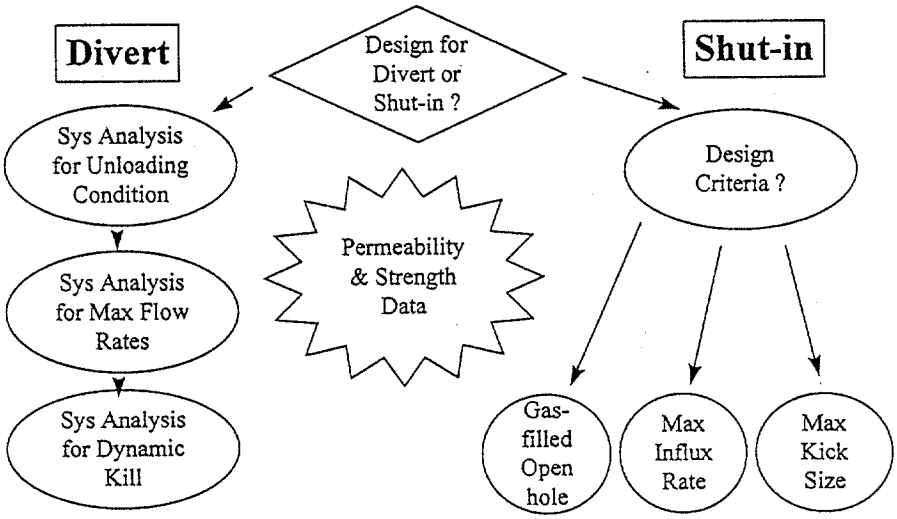
Possible Diverting Outcomes

- The well flows until the reservoir is depleted or the borehole bridges over.
- A dynamic kill is successfully completed within the well or by using a relief well.
- Sediments are excavated from around the borehole and flow paths are created for the blowout to broach to the surface.
- Diverter failure.

Shallow Water Flow Problem in Deepwater



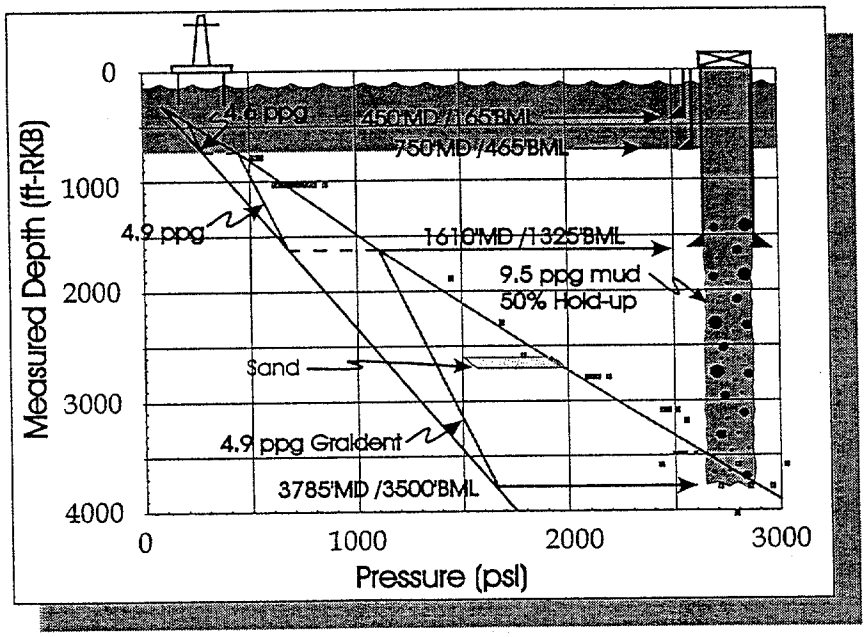
Decision Tree for Shallow Gas Casing Design



Shutting-in on Shallow Kicks

- Shutting-in on a kick is an attempt to re-gain pressure control of a well and prevent the well from blowing out.
- Conditions which favor shutting-in:
  - Floating drilling vessel OR
  - Competent casing shoe AND/OR
  - High probability that an underground blowout will not broach (Designed for shut-in).

Gas/Mud Mixture Design



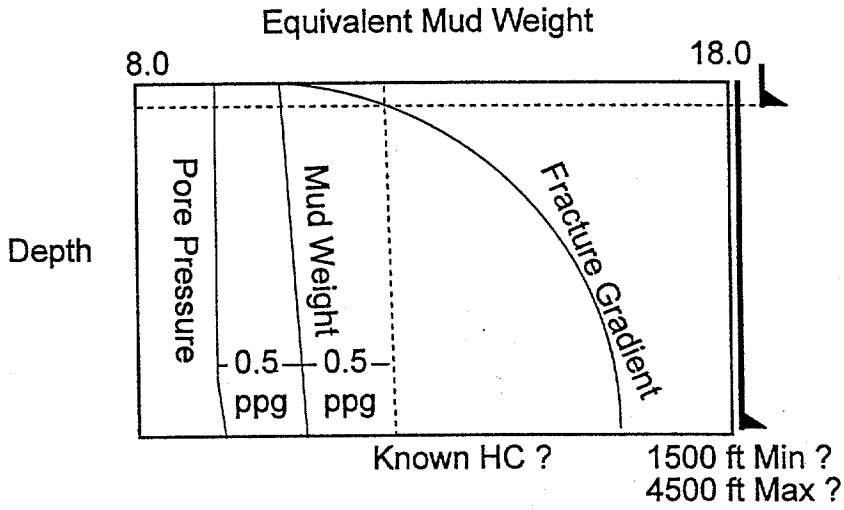
Shallow Blowout Statistics on OCS for Past 25 Years Indicate:

- No Oil Polution.
- No Fatalities.
- Blowout usually stops within a week.
- Relief Well is generally feasible if blowout continues.

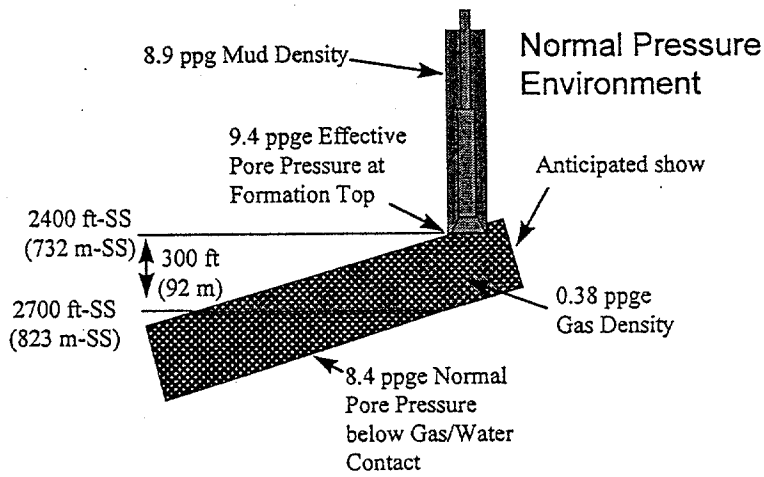
Additional Cost to Shut-in on Gas/Mud Mixture in Open Hole

- Estimated Additional Cost = $120,000/well
- 1 of 243 Exploration wells have shallow gas blowout
  - Well cost must be > 120,000 x 243 = $29,000,000 to justify this design on cost alone
- 1 in 2,000 structures have been lost are severely damage
  - Structure cost must be > 2,000 x 120,000 = $240,000,000 to justify this design on cost alone

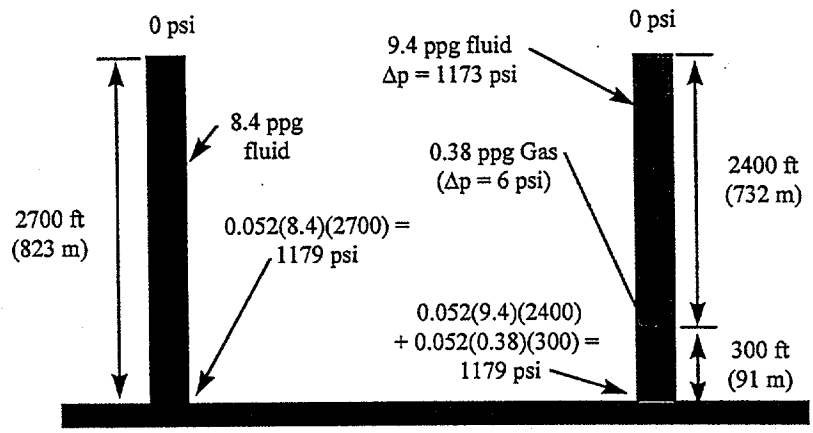
MMS
Surface Casing Requirements



Example Problem --Plan to Drill to 8000 ft with 500 ft of Casing



Density Contrast Effect



Gas Density Estimate: $pM/(80.3zT) = (1045+15)(16)/\{80.3(1)(460+100)\} = 0.38$ ppg

Task 2 - Prevention of Flow After Cementing Casing

- 2A-Review of Case Histories
- 2B-Current Technology for Prevention
  - 2B1-Top Cement Pulsation
- 2C-Current Operator Policy for Handling.
- 2D-Computer Model Development.
- New 2Aa-- SCP Testing Procedures
- New 2Ab-- Annular Displacement Methods

Task PB1B-Improved Kick Tolerance Analysis Modeling

- Develop advanced kick simulator dedicated to kick tolerance and "killable kh" calculations.
  - Build upon Petrobras Sponsored study (Ohara).
  - Experimental work defining the gas distribution profile in the annuli along the migration path.
    - Countercurrent Migration in Horizontal Well.
    - High Rate Kick Influx.

Task 3 - Feasibility of Automated Detection of UGB

- 3A-Modify LSU No. 1 Well for study of UGB.
- 3B-Update well control automation software to include underground flow detection capability (Kelly).
- 3C-Modification of gas compression facility to allow simulation of UGB.

Now Working with Swaco for possible Well Control Automation Implementation.

Task 4 --Subsurface logging methods for verifying UGB

- Develop a recommended practice for employing and interpreting currently available logging tools (noise, temperature, & nuclear gas detection).
  - 4A-Temperature logging methods and interpretation.
  - 4B-Noise logging methods and interpretation.

Task 5 -Interpreting surface pressure during UGB with Oil-Base Mud

- Build upon previous work from DEA Project 7 which produced down-hole well data during a gas kick with oil base muds in the hole.
  - Modify Computer model for Oil Base Muds
  - Test Model using data collected from DEA 7.

Eliminate Task 5 to Increase Scope of Other Tasks ?

Task 6 - Study of Bullheading Procedure for UGB

- 6A-Develop computer model for predicting viability of bullheading in a given situation.
  - Experimental Data in Research Wells on Countercurrent Gas Migration (Koederitz)
  - Experimental Data in Inclined Flow Loop.
- 6B-Test and update model, transfer technology, and develop recommended practice.

Task 7 - Experimental Evaluation of Plugging Techniques for UGB

- Compile data on plugging agents and well placement techniquesfor UGB.
- Develop recommended practice for design of plugging treatment.

Eliminate Task 7 to Increase Scope of Other Tasks?

Task 8 - Requirements for Dynamic Kill of UGB

- 8A-Design and develop dynamic kill simulator with capability to handle hydraulic fracture (Negrao).
- 8B-Develop recommended practice for design of dynamic kill for UGB.
- 8C-Design & Test improved DSSV.

Recommend Increased Scope of DSSV Work

Task 9 -Review of Recent Diverter Failures

- Analyze diverter failures since the last report to determine if reliability has improved.
- Summarize failure mechanisms such as plugging and erosion.
- Document modern diverter configurations currently in use based on MMS records.

Task 10 - Post-analysis of recent blowouts and near misses

- Screen case histories of recent UGB for important mistakes and lessons learned.
  - Excellent cases provided by *Mobil Oil Co.*, *Phillips Petroleum Co.*, and *Amoco Oil Co.*
- Select 5 cases for detailed simulation & analysis.
  - Simulator provided by *Computer Simulation, Inc. (Just received last week)*
- Prepare 5 Training Modules

Task 11 - Review of Sustained Casing Pressure Problems

- 11A-SCP Database
- 11B-Review of Operator Procedures
- 11C-Case Histories of Remediation Attempts.

Task 12 - LSU/MMS Well Control Workshops

- May 23-24, 1995 --Well Control
- November 19-20, 1996 --Well Control
- July 30, 1997 -- Deepwater Drilling
- March 31-April 1, 1998 -- Deepwater Multiphase Flow & Well Control

Problems Encountered which have slowed Progress

- Loss of Key Personnel
  - Allen Kelly
  - Ted Bourgoyne (Partial)
- Graduate Student Recruitment
  - Enrollment at 20 year low
  - Current Industry demand is high (Several Research Assistants took jobs before finishing graduate degree)
- Proprietary Concerns of Operators & SC

Recommended Project Changes

- Eliminate Tasks 5 (Oil Base Mud Study)
- Eliminate Task 7 (UGB Plugging Agents).
- Increase Scope of Task 8 concerning DSSVs.
- Increase Scope of Tasks 2 (GRI Project).
- Add Dr. Bassiouni to project (Task 4).
- Add Dr. Ghalambor (USL) to project (Task 9).
- Add New LSU Personnel as Hires are made.

Mapping of the Gas Flow Hazard After Cementing

by

Andrew K. Wojtanowicz, and

Somei Nishikawa, LSU

LSU/MMS Work Control Workshop,

Louisiana State University

Baton Rouge, Louisiana,

April 1, 1998

OBJECTIVE

- Analysis of case histories; flowing wells (16) and non-flowing wells (14)
- Correlation of known flow risk indices
- Identifying critical data for analysis
- New method for time gas flow time ratio for flow risk quantification

Case History - Flowing Wells

No.	Elevation Data		Last CSG				Hole Data			Running Casing						Cement Data			
	ED	WD	OD	Shoe	Pressure Data		Bit	MW	DS	Size	Set Depth			Pressure Data		Lead		Tail	
	(ft)	(ft)	(in)	(ft)	Frac. (ppg)	Pore (ppg)	Size (in)	(ppg)	(dgr.)	OD (in)	MD (ft)	TVD (ft)	LFC (ft)	Frac. (ppg)	Pore (ppg)	Volume (cf)	WT (ppg)	Volume (cf)	WT (ppg)
1	100	70	16	1000	11.4	9	14.75	9.2	35	10.75	4045	3940	40	14.4	9	3509	11.7	603	16.4
2	190	90	20	1105	10.8	9	17.5	9.2	0	13.375	4760	4780	40	14.8	9	4211	11.9	2184	16.4
3	125	194	16	1013	12	9.5	14.75	11	0	10.75	4550	4550	60	15.1	9.5	2944	12	650	16.4
4	97	236	20	1243	12.8	9	20 (UR)	11	0	16	3991	3991	40	14.9	9	3588	11.4	1387	16.2
5	161	209	24	530	11.7	8.4	22	9	23.7	16	829	829	40	12.2	8.4	1178	12	292	16.2
6	100	209	20	1000	11	9	17.5	9.5	0	13.375	5462	5462	40	15.3	9.2	5738	11.4	654	16.2
7	100		18.625	1335	11	9	17.5	10	45.5	13.375	1386	1386	80	14.1	9.5	3178	12.6	943	16.2
8	99	398	26	1414	12.3	9	24	11	0	20	3326	2236	40	15.5	10.5	3690	12.2	1044	16.4
9	110	651	16	1933	12	9	14.75	11	32	10.75	4270	4120	80	13.6	9.2		12.6	1575	16.2
10	36	101	20	1000	?	9	17.5	10	0	13.375	2000	2000	80	?	9.5	1950.4	12	520	16.2
11	96	200	20	979	?	9	17.5	9.8	0	13.375	4000	3500	80	?	9	3178	12.5	943	16.2
12	65	103	30	322	?	9	18.5	10	0	13.375	2698	2698	0	?	9	0	12.6	2124	15.6
13	85	180	16	632	0.4EST	9	13.5	9.9	14.8	10.75	2563	2501	40	12.5	9.2	1030	11.8	348	13.4
14	55	263	20	1104	11.2	9	17.5	9.4	0	13.375	4088	4088	80	15.5	9	4536	12.4	354	15.6
15	105	338	16	1035	?	8.3	13.75	10	0	10.75	2716	2716	40	14.3	10	2016	12.6	236	15.6
16	90	175	16	800	10EST	9.4	17.5(UR)	10	0	13.375	4707	4707	40	13.8	9.4	0	16.2	4461	16.2

Case History - Non Flowing Wells

Well No.	Last CSG Shoe (ft)	Running CSG Depth (ft)	Running CSG Depth TVD (ft)	Lead Slurry (cuft)	Cement Weight (ppg)	Tail Slurry (cuft)	Cement Weight (ppg)	Water Depth (ft)	Elevation (ft)	Mud Weight (ppg)	Float Shoe Length (ft)	Hole Deviation (deg)	CSG Size (in)	Fracture Pressure (eq.ppg)	Pore Pressure (eq.ppg)
1	1000	5000	5000	5882	11.4	766	16.2	55	80	9.9	40	0.0	13.38	15.0	9.9
2	1200	5545	4000	2600	11.5	920	16.4	194	287	9.8	80	56.8	13.38	14.8	9.2
3	1000	4373	4000	1207	12.7	650	16.4	170	100	9.5	80	41.0	13.38	14.0	9.0
4	800	1600	1600	250	11.4	375	16.2	190	100	9.3	80	0.0	10.75	11.6	8.8
5	2150	3648	3500	1200	13.1	500	16.2	1024	105	10.4	80	0.0	10.75	13.4	9.0
6	2150	3648	3500	1125	13.1	660	16.2	100	106	9.3	80	34.8	10.75	13.9	9.0
7	750	3000	3000	0	16.2	1350	16.2	74	92	9.3	80	0.0	10.75	13.5	8.8
8	465	5492	5492	0	16.2	4132	16.2	89	98	9.3	80	0.0	10.75	13.7	8.8
9	465	3300	3300	914	12.0	515	16.4	210	85	9.0	80	0.0	10.75	14.0	9.0
10	900	2150	2150	0	12.5	694	16.4	188	125	10.5	80	0.0	9.63	13.3	9.5
11	900	3100	3100	0	12.5	3519	16.4	95	100	9.3	40	0.0	13.38	13.5	8.8
12	900	3475	3000	971	12.5	370	16.4	122	100	9.5	40	50.4	10.75	13.5	9.0
13	2150	3648	3648	1200	13.1	500	16.4	1024	105	10.4	40	0.0	10.75	13.4	9.0
14	2003	3648	3648	623	13.0	1790	16.2	240		12.5	80	0.0	16.00	16.2	12.0

Present Methods for Gas Flow Risk Analysis

1. Flow Potential Factor - 1984
2. Slurry Response Number - 1989
3. Slurry Performance Number - 1989

Flow Potential Factor - 1984

static Gel Strength

$$\text{FPF} = \frac{\text{Maximum Pressure Drop (till SGS} = 500\text{lb}/100\text{ft}^2)}{\text{Initial Overbalance}}$$

Drawback:	It uses an arbitrary SGS limit and an idealized homogenous borehole.

Slurry Response Number - 1989

$$SRN = \frac{\text{Maximum Rate of SGS Increase}}{\text{Rate of Slurry Shrinkage (due filtration)*}}$$

*at time when the rate of SGS increase is maximum

Drawback:	It ignores SGS changes in time and disregards borehole conditions.

Slurry Performance Number - 1989

- Formation Factor = $\frac{\text{Gas Formation } k*h}{\text{Cement Pore Volume (Porosity = 0.02)}}$
- Hydrostatic Factor = $\frac{\text{Gas Pore Pressure}}{\text{Slurry Hydrostatic Pressure (initial)}}$
- Mud Removal Factor = Fraction of annulus filled up with slurry
- Slurry Performance Factor = Slurry shrinkage (filtration) during transition time

Drawback:	Input data are not available (k, h, p_g); Hydrostatic pressure loss is ignored.

Shortcomings of Current Risk Indexing Methods

- Assume that gas flow can be predicted from a few selected mechanisms - determinate approach
- Over-emphasize the importance of cement slurry properties measured at laboratory conditions (water loss, for instance)
- Ignore borehole stratification effect:

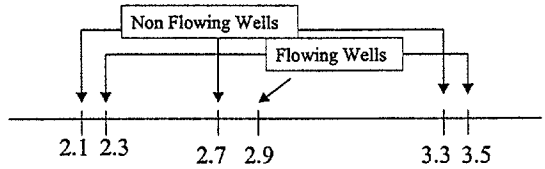
*A single "bridge" in cement column (due local fluid loss) may "unload" bottomhole hydrostatic pressure, for example; or,

*a single "plug" in cement column (due local impermeable zone and lack of filter cake) may stop gas flow upward.

Flow Potential Factor for 16 cases of flow after cementing and 14 cases of non-flowing wells in GoM

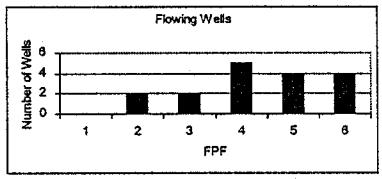
Flowing Wells			Non-Flowing Wells
Flow observed on surface hrs	FPF d'less	Time to earliest pressure balance hrs	Time to earliest pressure balance hrs
?	0.9	2.5	2.2
?	4.5	2.5	2.5
?	2.6	2.3	2.7
5.5	4.1	2.5	2.5
10.5	1.2	2.8	2.7
3.5	3.1	2.3	2.7
?	2.2	2.5	2.5
?	1.0	2.5	2.5
5.5	3.8	2.7	2.5
2.3	2.8	2.5	2.5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

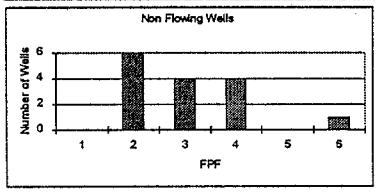
Statistical Analysis of the FPF's for the flowing and non-flowing wells



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**





Gas Flow Time Ratio Method

- Gas Time Ratio is defined as:

$$R = \frac{\textbf{Underbalance time, } t_{und}}{\textbf{Surface gas time, } t_{sfg}}$$

Where:

R = gas time ratio, dimensionless

t_{und} = theoretical time to reach underbalance at casing shoe; It is a calculated quantity from slurry properties, last mud density using a mathematical model, hrs

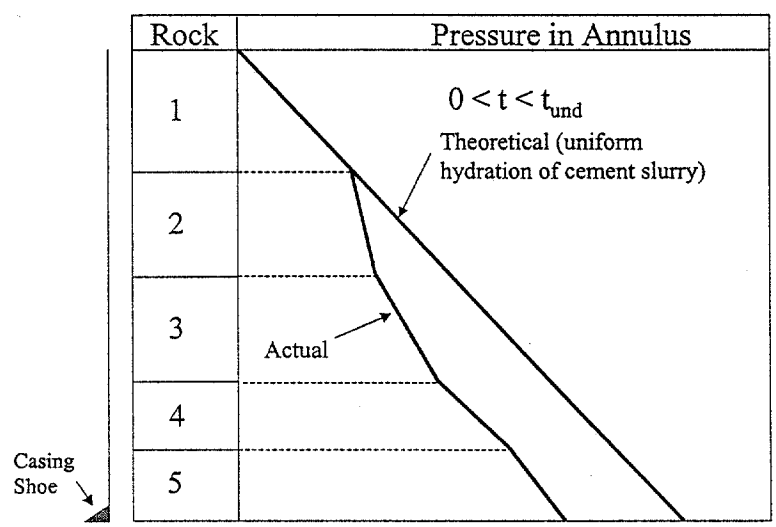
t_{sfg} = recorded time of gas showing at the surface after the end of cementing, hrs

Gas Flow Time Ratio Method (continued)

- The $\mathbf{t_{sfg}}$ parameter is **a measured quantity** representing combined effects of all other factors involved in the " early" and "long-term" gas leakage, including the "Sustained Casing Pressure" effect.

- The $\mathbf{t_{und}}$ parameter is **a calculated quantity** representing predicted loss of hydrostatics (property of cement slurry: gelation, filtration, shrinkage) combined with a common-sense condition for pressure balance in the well (mud weight).

Calculated $\mathbf{t_{und}}$ Overestimates the Actual Time-to-Underbalance (?)



Calculation of Time-To-Underbalance

$$P_h(z,t) = P_{hi} - \xi(t)\cdot\zeta(z)\cdot\frac{4\cdot SGS(z,t)}{D_h - D_o}\cdot z$$

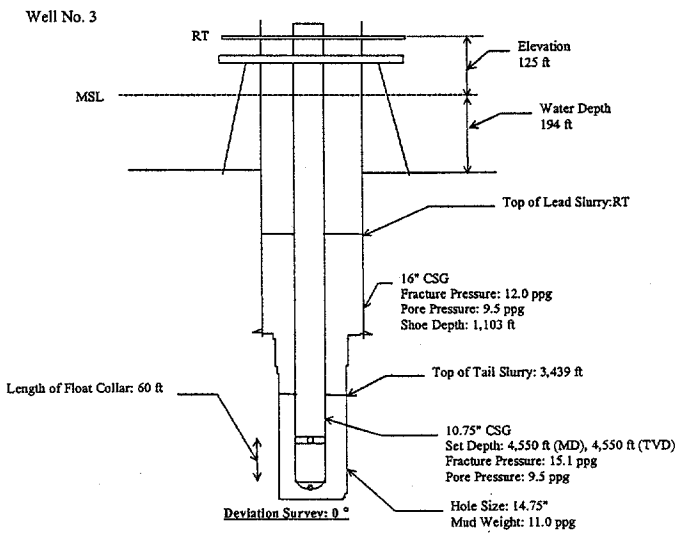
$$P = 0.052\,\rho L - \frac{SGS\ \cdot L}{300\ \cdot D}$$

Where:

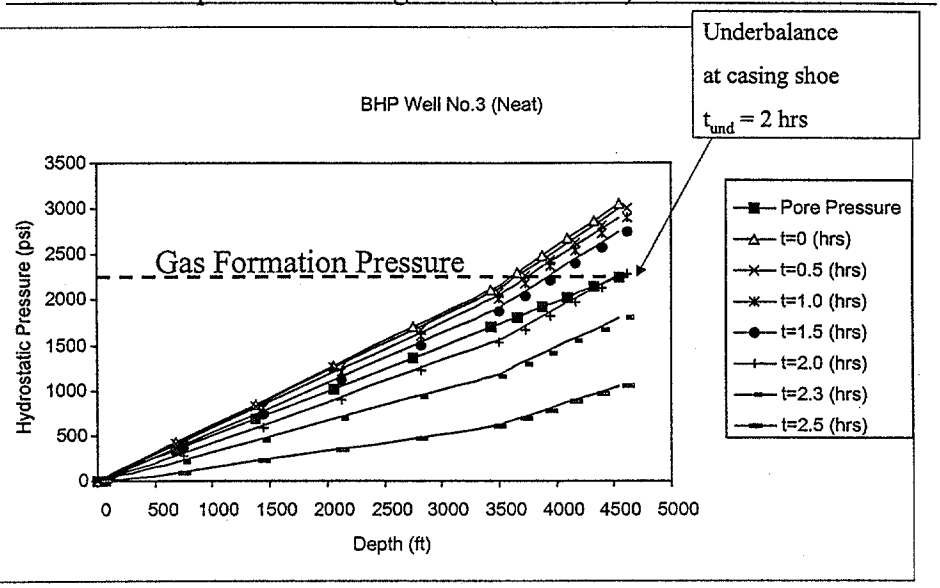
$\xi(t)$ = effect of filtration, dimensionless

$\zeta(z)$ = effect of shrinkage, dimensionless

Example of a Flowing Well



Example of a Flowing Well (continued)



Gas Flow Time Ratio Method - Results

Flowing Wells

Well No.	Location	Flowing Time (hour)	Time at Underbalance (hour)	R
1	BA557	7	2	0.29
2	EI 193	8	2.3	0.29
3	SS 248	6	2	0.33
4	GI 102	5.5	2.2	0.40
5	MP 229	7	2.3	0.33
6	PN 1018	2.5	2	0.80
7	MP 229	2.3	2.1	0.91
8	ST 289	5.5	2	0.36
9	MC 0148	0	2.5	∞
10	MI 664	3.5	2	0.57
11	WD 086	1	2.2	2.20
12	SM 048	0	2.5	∞
13	SS 269	?	1.7	?
14	EI 327	?	2	?
15	EI 380	5.5	1.7	0.31
16	SM 096	10.5	2.3	0.22

Non Flowing Wells

Well No.	Location	R
1	MP 106	0.00
2	EI 342	0.00
3	ST 206	0.00
4	HI A468	0.00
5	HI A468	0.00
6	EI 208	0.00
7	BA 552	0.00
8	SM 33	0.00
9	PN A27	0.00
10	SS 248	0.00
11	SM 048	0.00
12	MI 620	0.00
13	MC 150	0.00
14	GI 102	0.00

Discussion of R

- Utilizes the only one parameter of gas flow available from field reports - $\mathbf{t_{sfg}}$
- Represents both the slurry ($\mathbf{t_{und}}$) and the borehole ($\mathbf{t_{sfg}}$);
- Comprises a complex interaction between cement slurry and a borehole in just a single number;

Discussion of R (continued)

- Considers both flowing (R=0) and not-flowing (0<R<1) wells;
- Diagnoses abnormalities (R>1),i.e. cases when gas flow does not result from well's underbalance at casing shoe;
  - shallow gas zone;
  - permeability stratification / LOC zones;
  - other mechanisms.
- Enables statistical treatment of field data, grouping (per slurry type), or mapping (per area)

TIME-TO-UNDERBALANCE CALCULATION

by
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LSU/MMS WORKSHOP PRESENTATION:

"Mapping of the Gas Flow Hazard After Cementing"

Baton Rouge, Louisiana
April 1, 1998

1. Objective

The objective of this work is to compute the time to reach underbalance for 16 flowing wells after cementing in the Gulf of Mexico using the static gel strength development of neat cement. These computed underbalance times are compared with actual flowing times of those wells.

2. Time-To-Underbalance Calculation

The pressure reduction due to the static gel strength is given by,

$$\Delta P = \frac{SGS \cdot L}{300 \cdot D} \qquad -(1)$$

Where
ΔP = pressure restriction due to SGS (psi)
SGS = static gel strength (lb/100ft^2)
L = length of interval (ft)
D = diameter (in)

$D = D_h - D_p$ when D_h = hole diameter
D_p = casing diameter

The hydrostatic pressure of cement slurry after cementing is given by,

$$P = 0.052\rho L - \frac{SGS \cdot L}{300 \cdot D} \qquad -(2)$$

Where
P = hydrostatic pressure of cement slurry (psi)
ρ = density of cement slurry (ppg)

The static gel strength of neat cement slurry is obtained from empirical data,

$$SGS = 0.0306t^2 - 0.0008t + 10 \qquad -(3)$$

Where
t = time (min) after pumping cement slurry

Table 2.1 and Figure 2.1 show relationship between time and static gel strength development of neat cement slurry.

Time (min)	Static Gel Strength Development (neat cement) (lb/100ft^2)
0	10.0
10	12.4
20	18.6
30	26.3
40	34.5
50	42.6
60	50.9
70	60.3
80	72.5
90	90.0
100	115.8
110	153.8
120	208.5
130	285.2
140	390.0
150	529.5
160	711.2
170	943.2
180	1234.4

Table 2.1 SGS Development vs. Time

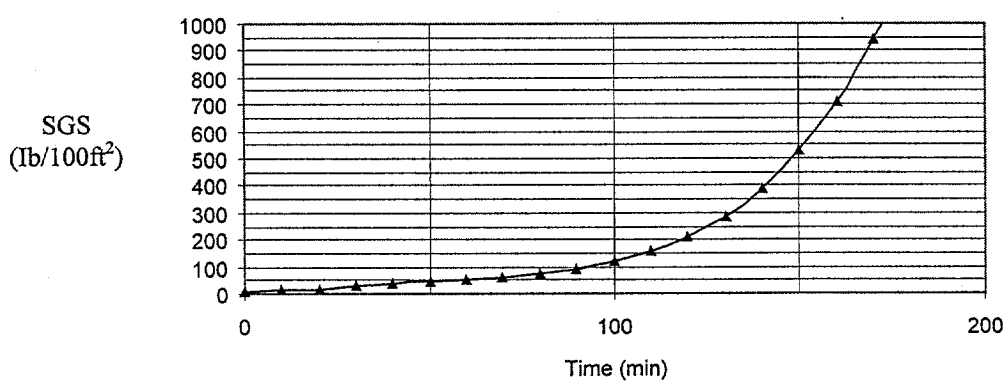


Figure 2.1 SGS Development

The data of 16 wells are shown in Attachment 1. Because casing IDs are not available in the data, the following table is shown assumed casing IDs, which are used in this calculation.

OD (in)	lb/ft	ID (in)
30	310	28.05
24	24	23.82
20	106.5	19.00
18.625	87.5	17.75
16	75	15.12
13.375	61	12.52
10.75	51	9.85

Table 2.2 Casing ID

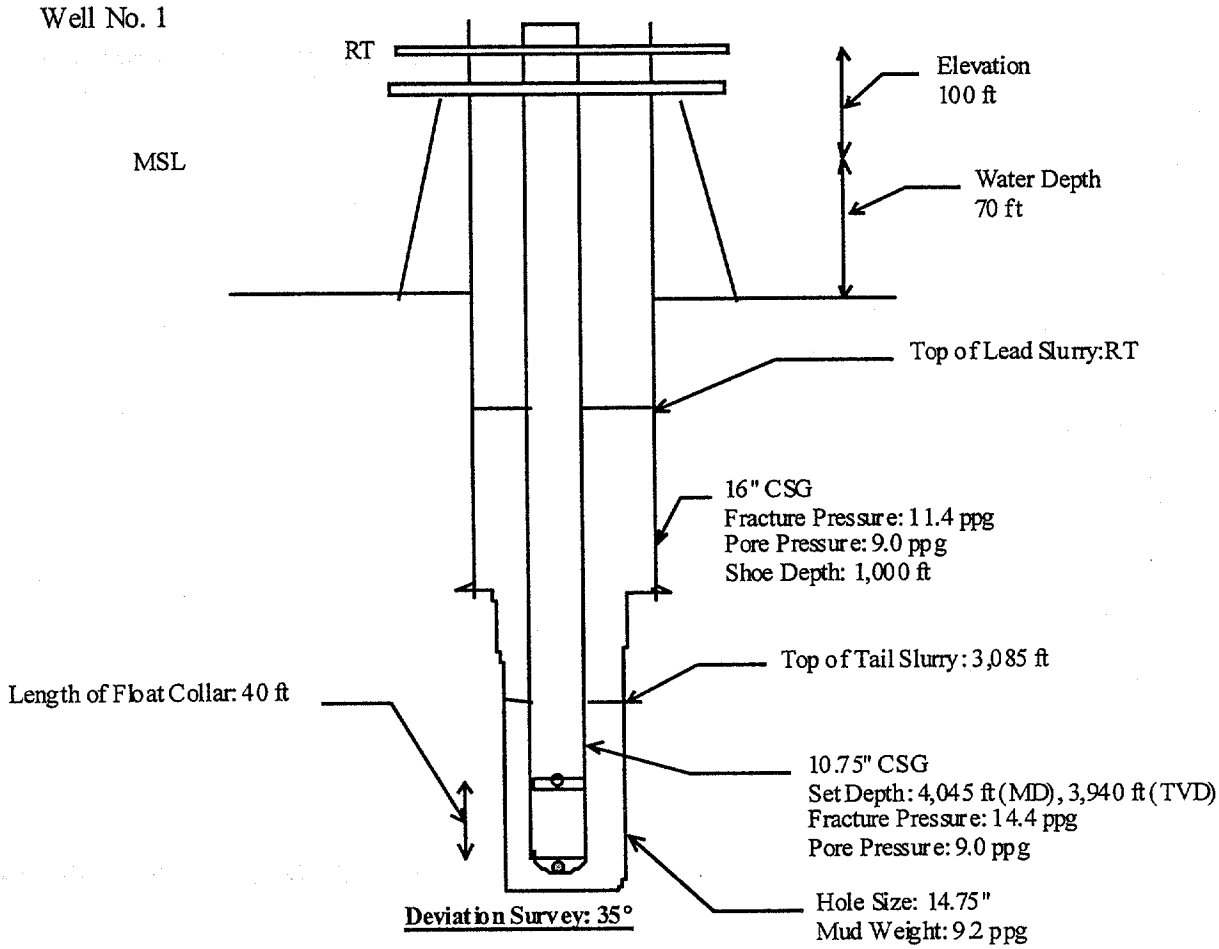
Table 2.3 shows the comparisons between actual flowing times and caluculated underbalance times. Figure 2.2 - 2.17 show underbalance times due to static gel strength (Well No.1 - Well No.16).

Well No.	Location	Flowing Time (hour)	Calculated Time at Underbalance (hour)
1	BA557	7	2
2	EI 193	8	2.3
3	SS 248	6	2
4	GI 102	5.5	2.2
5	MP 229	7	2.3
6	PN 1018	2.5	2
7	MP 229	2.3	2.1
8	ST 289	5.5	2
9	MC 0148	0	2.5
10	MI 664	3.5	2
11	WD 086	1	2.2
12	SM 048	0	2.5
13	SS 269	?	1.7
14	EI 327	?	2
15	EI 380	5.5	1.7
16	SM 096	10.5	2.3

Table 2.3 Comparisons between actual flowing times and caluculated underbalance times

Figure 2.2

Well No. 1



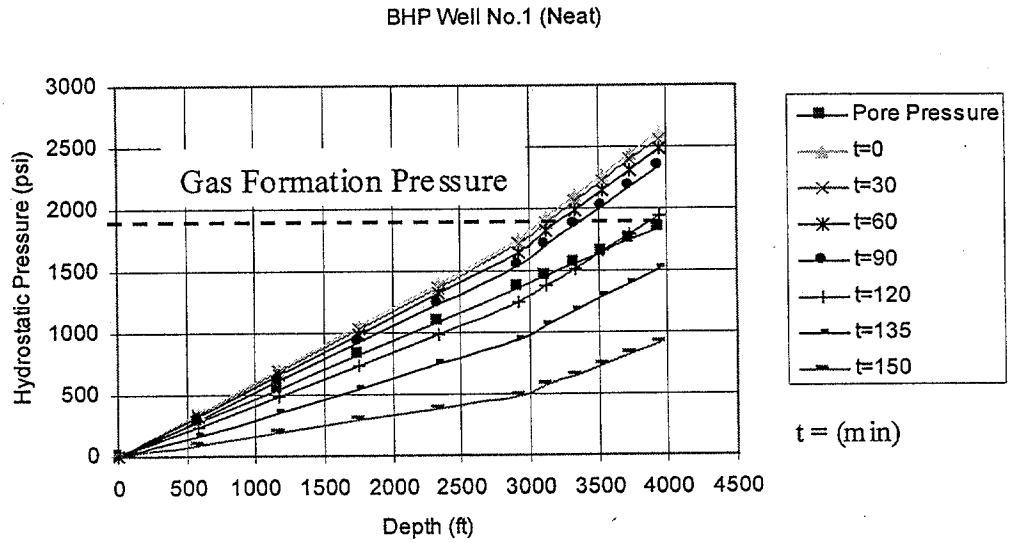
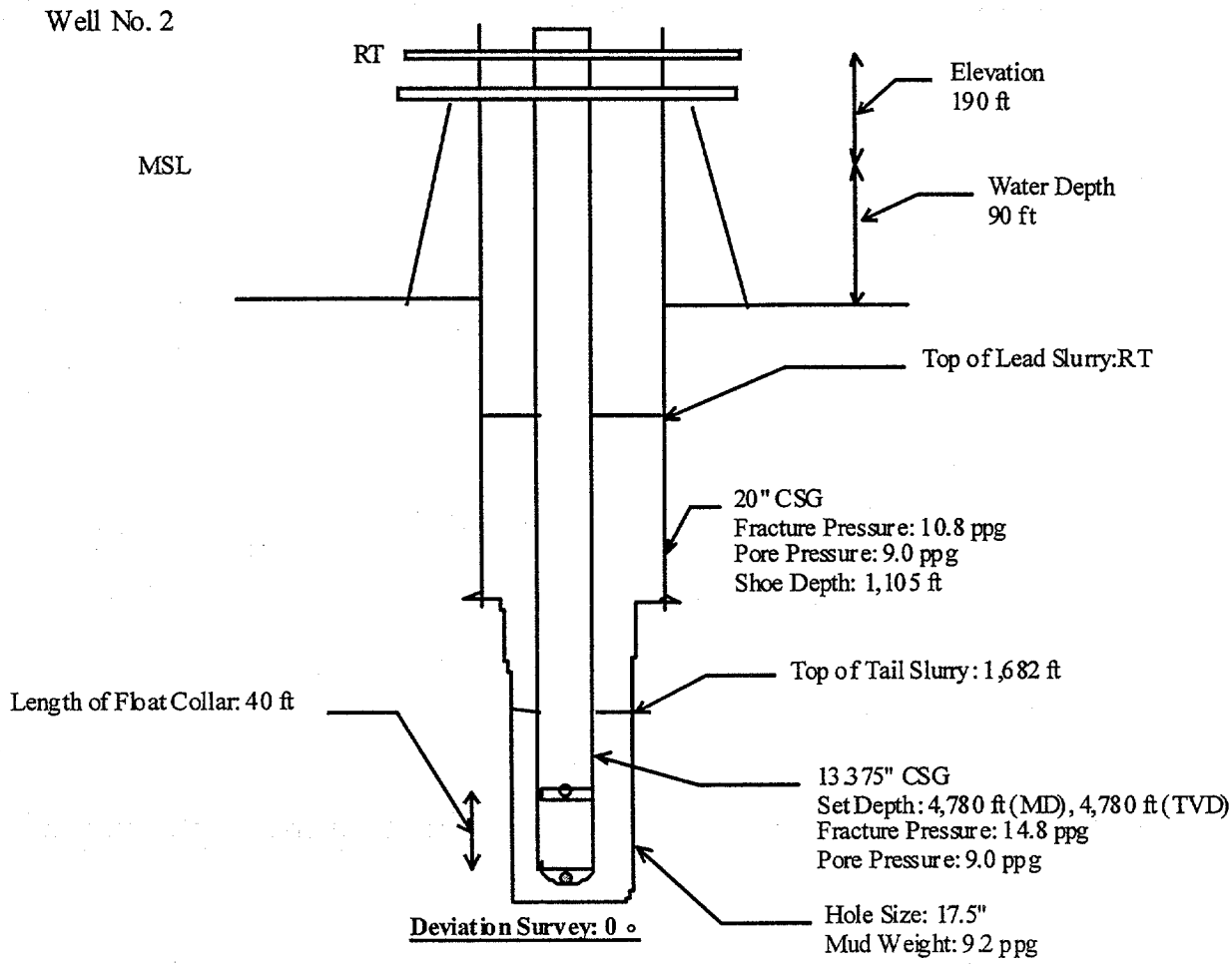


Figure 2.3
Well No. 2



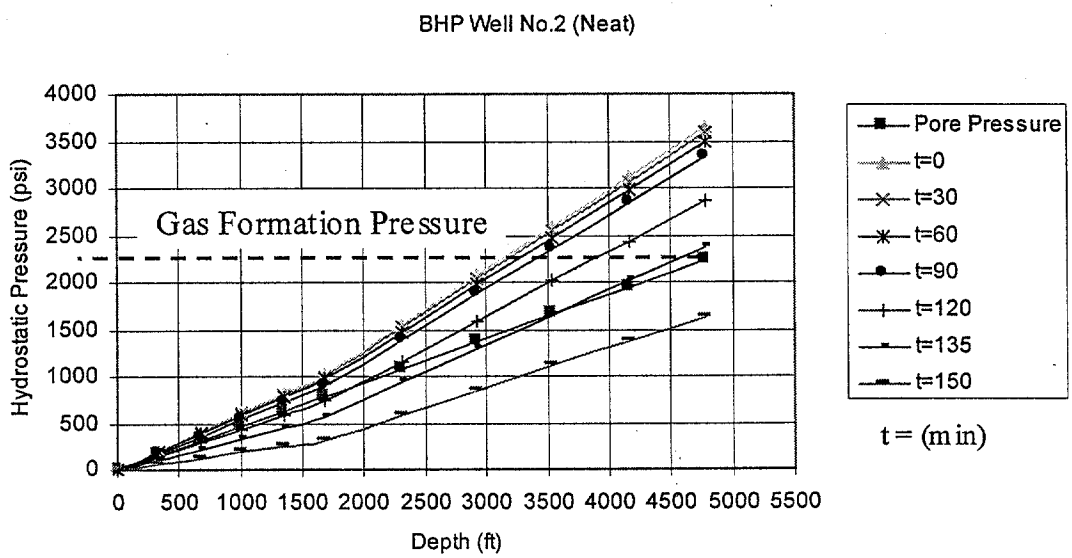
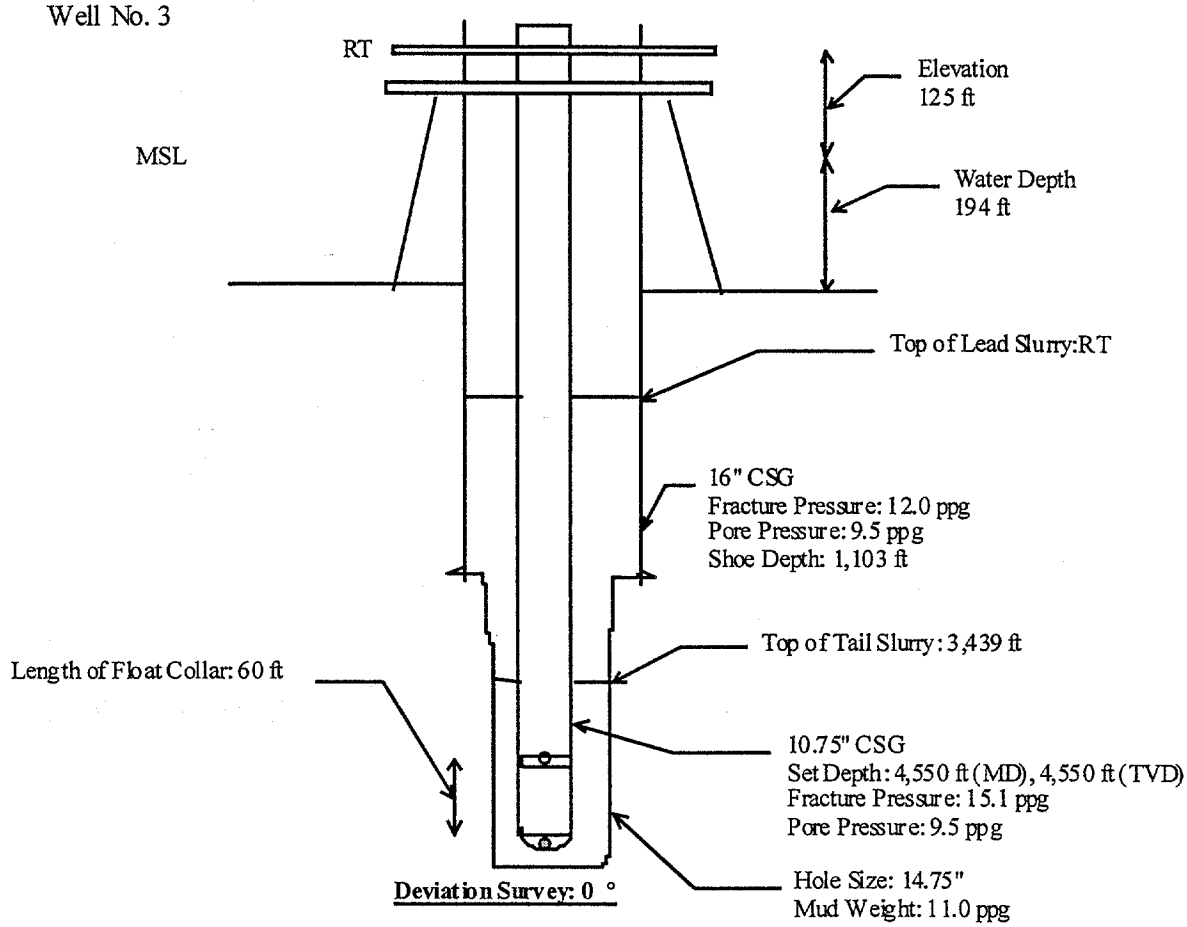


Figure 2.4
Well No. 3



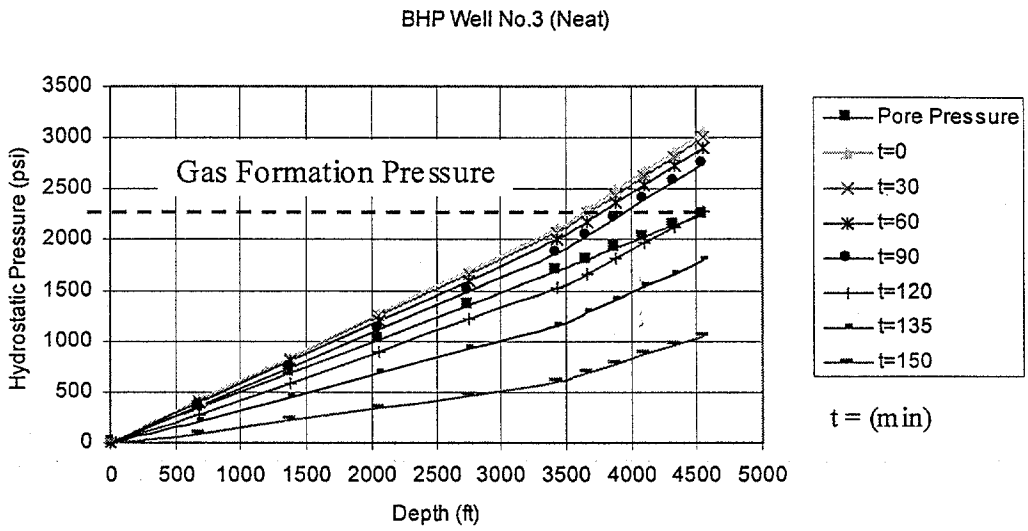
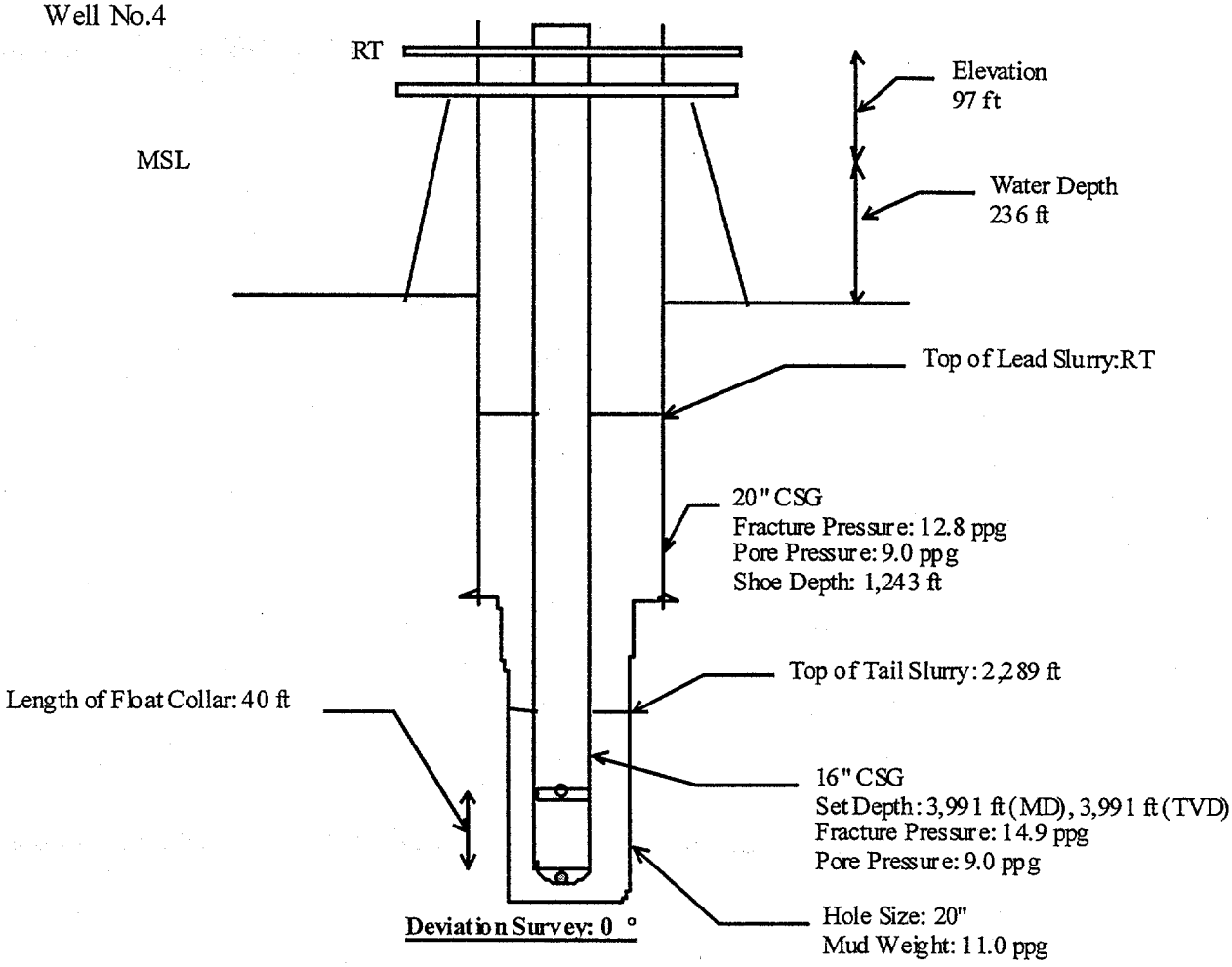


Figure 2.5
Well No.4



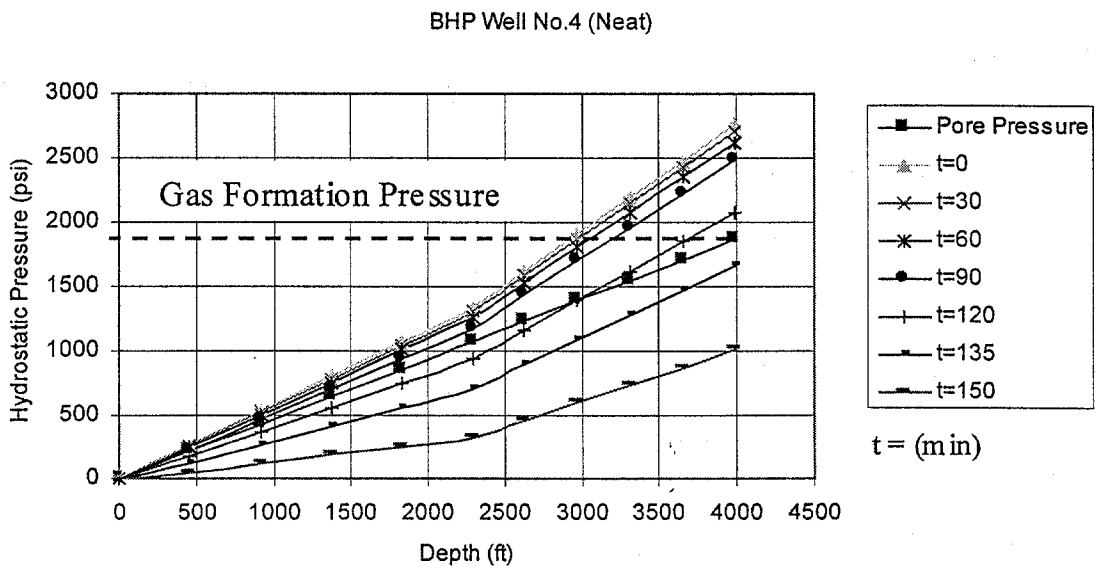
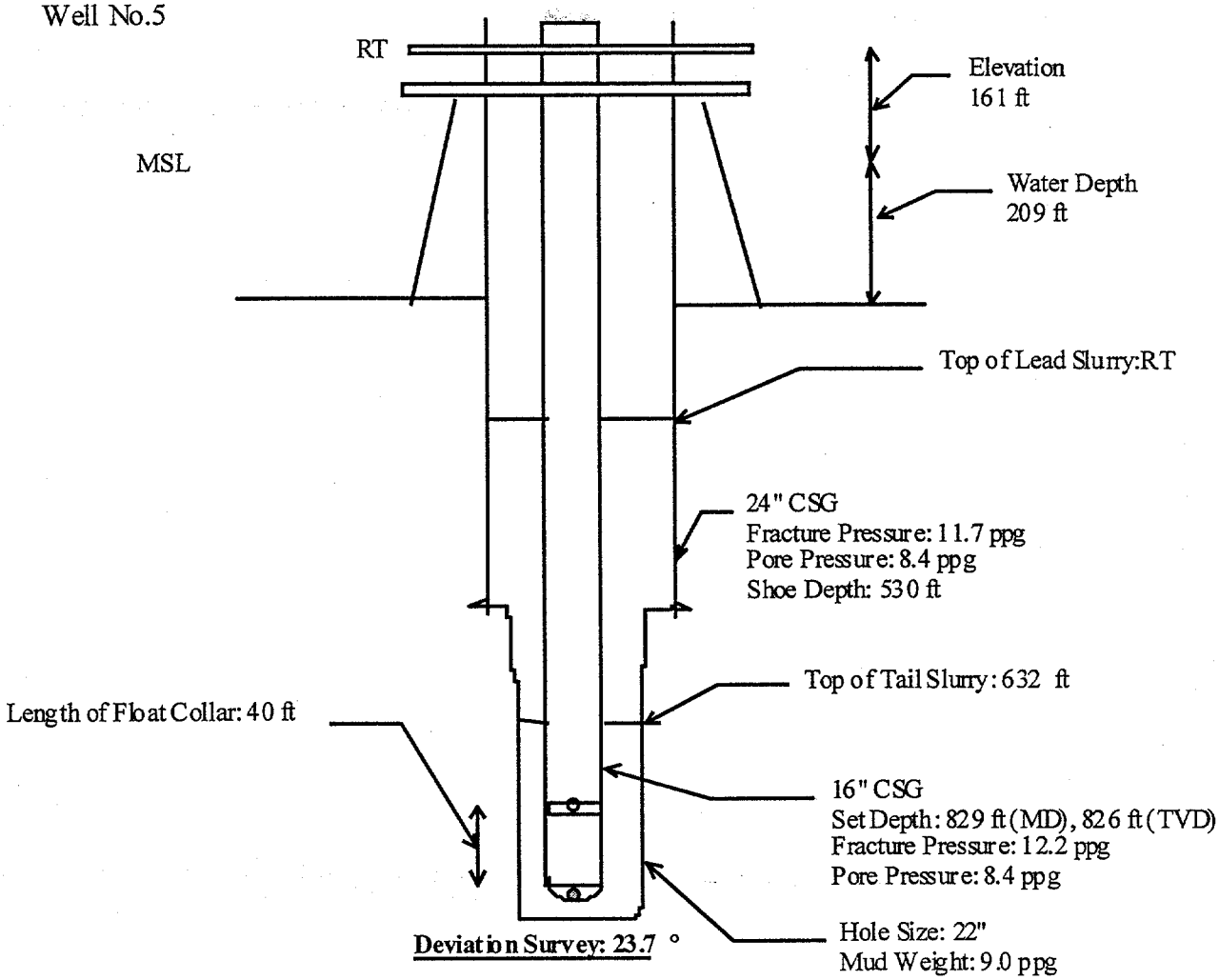


Figure 2.6
Well No.5



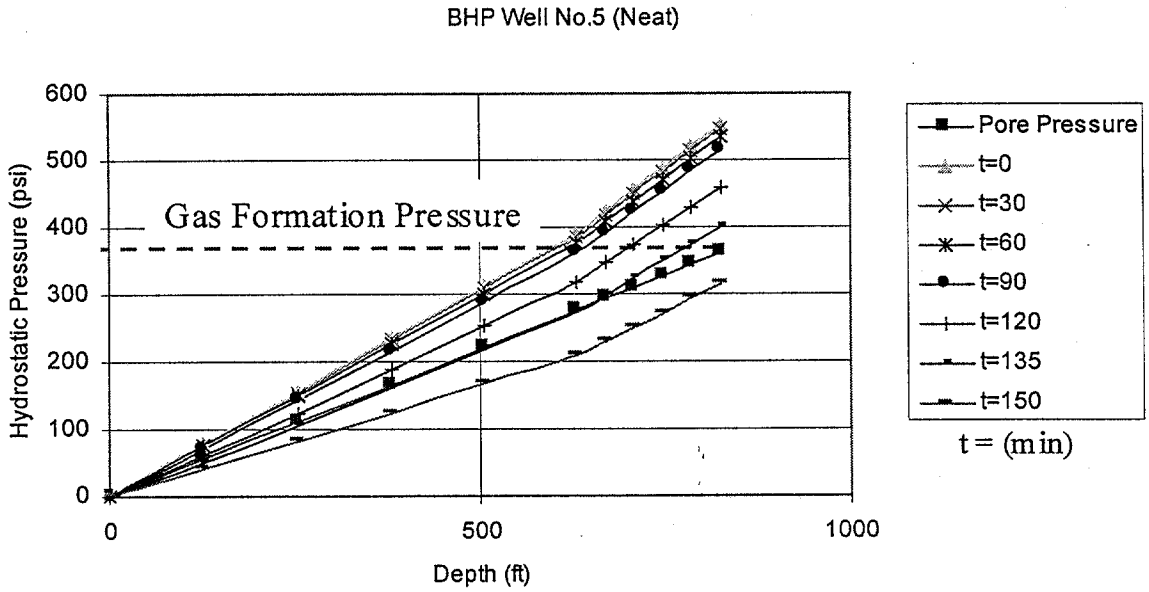
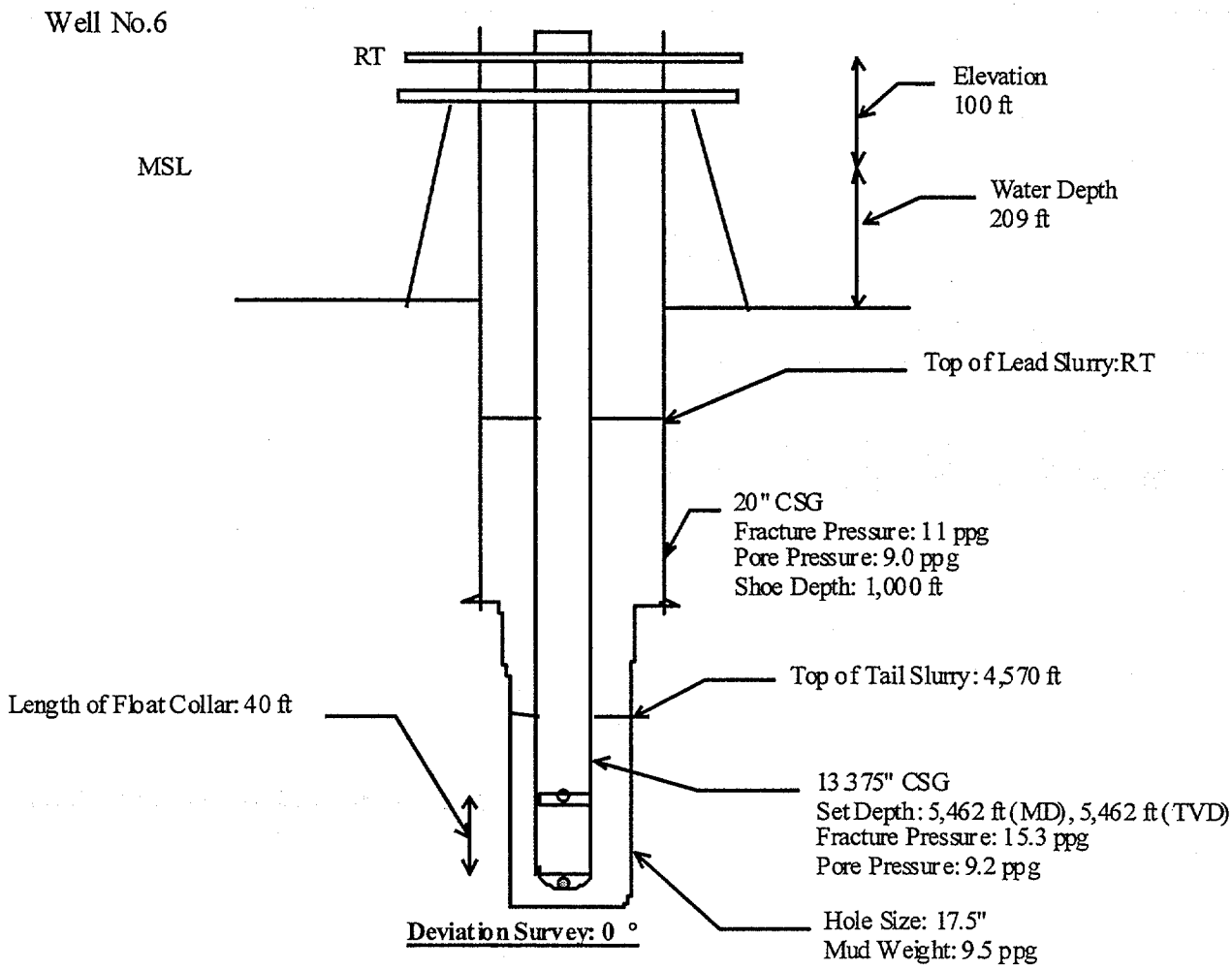


Figure 2.7

Well No.6



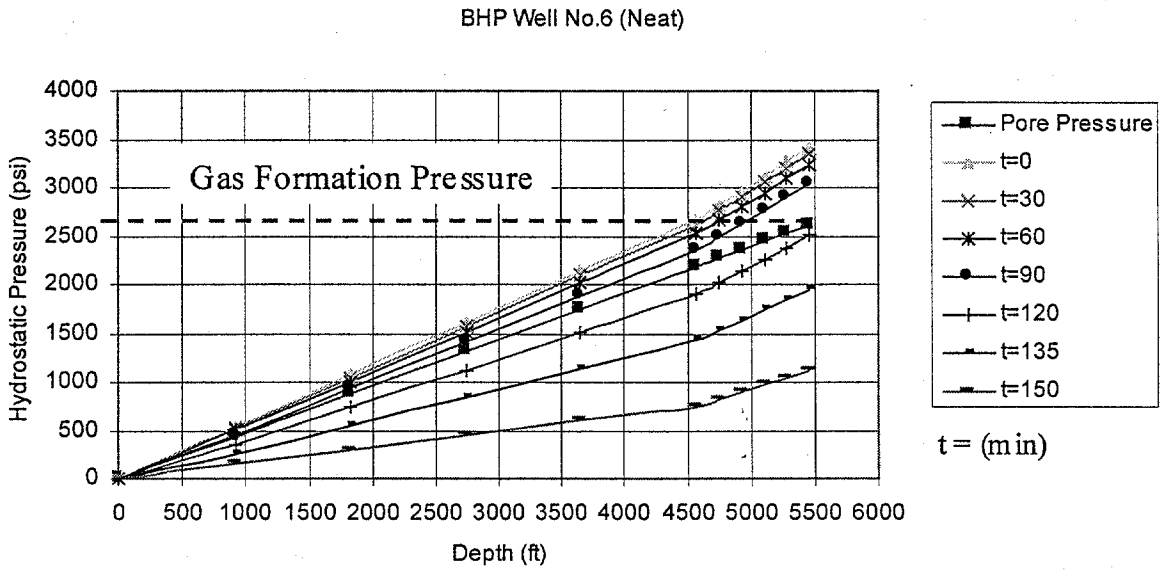
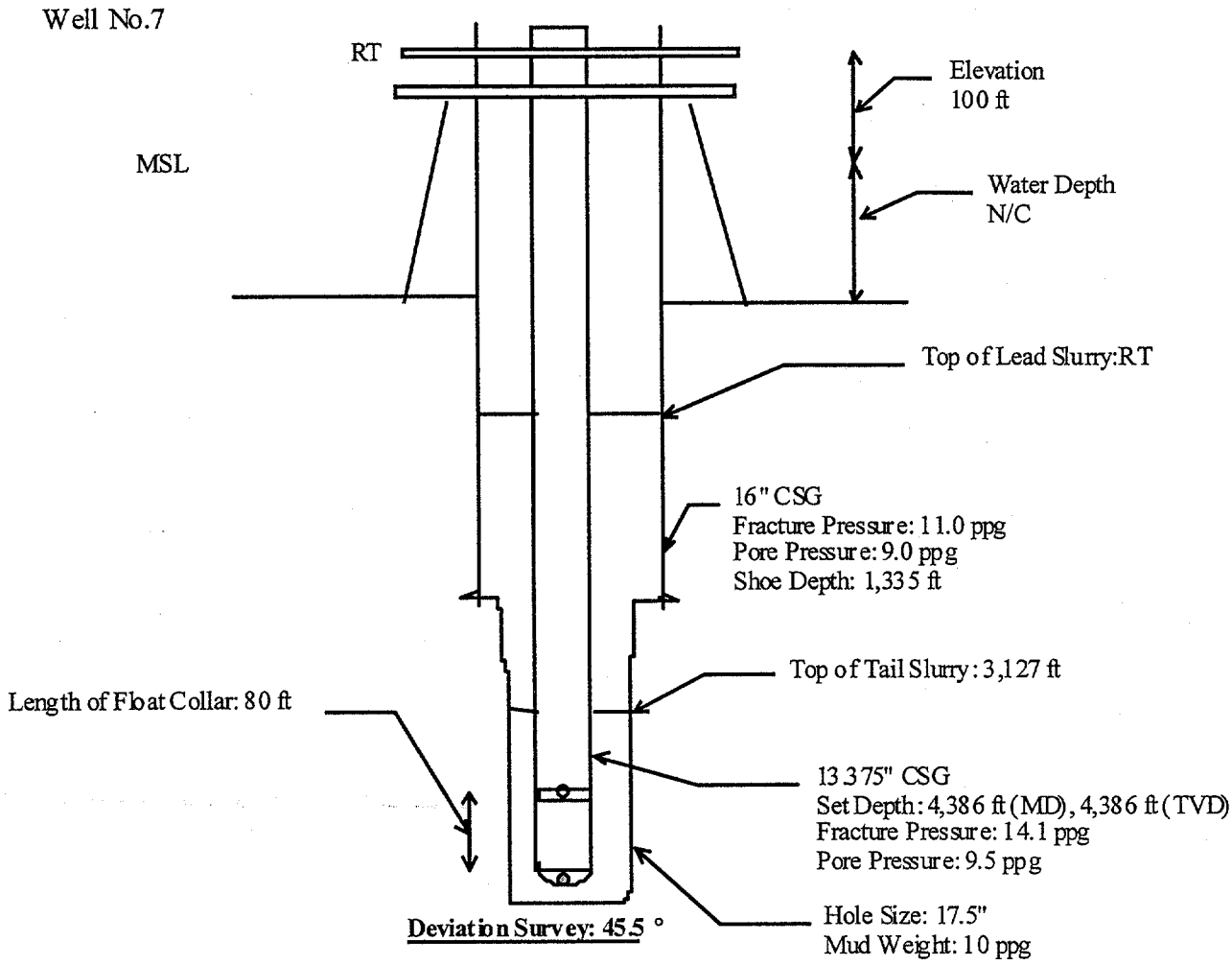


Figure 2.8

Well No.7



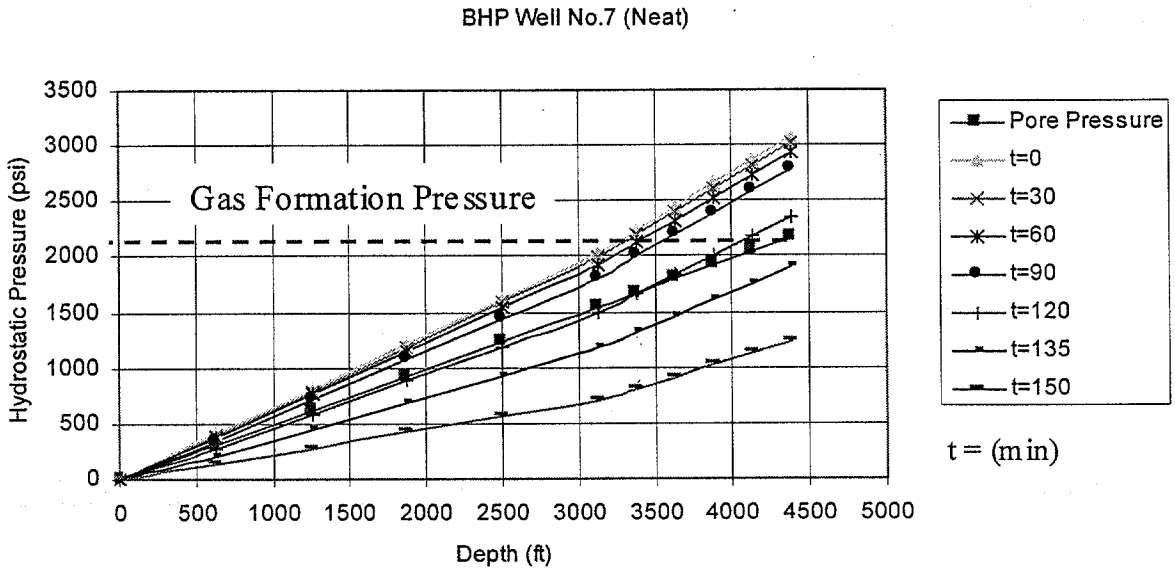
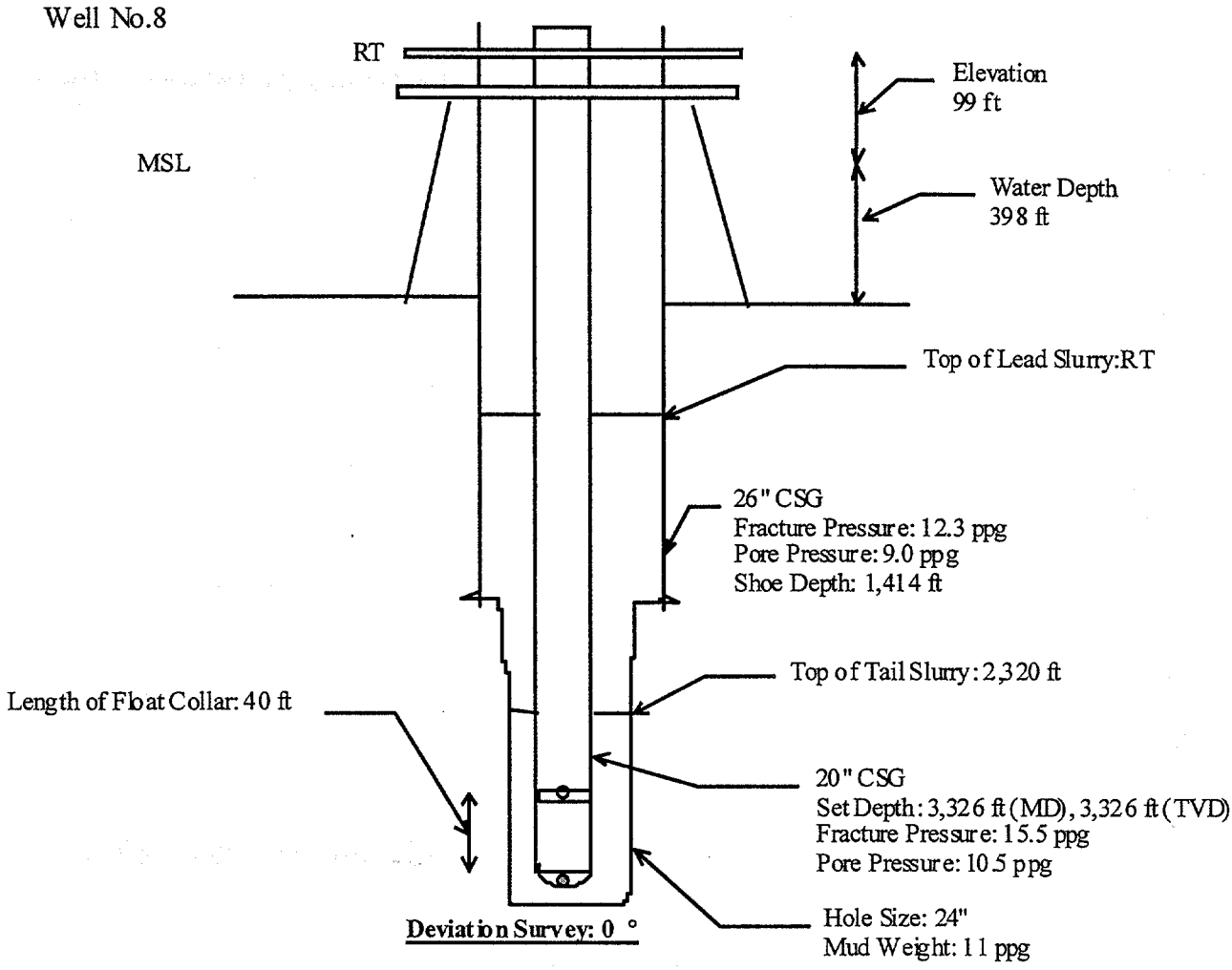


Figure 2.9

Well No.8



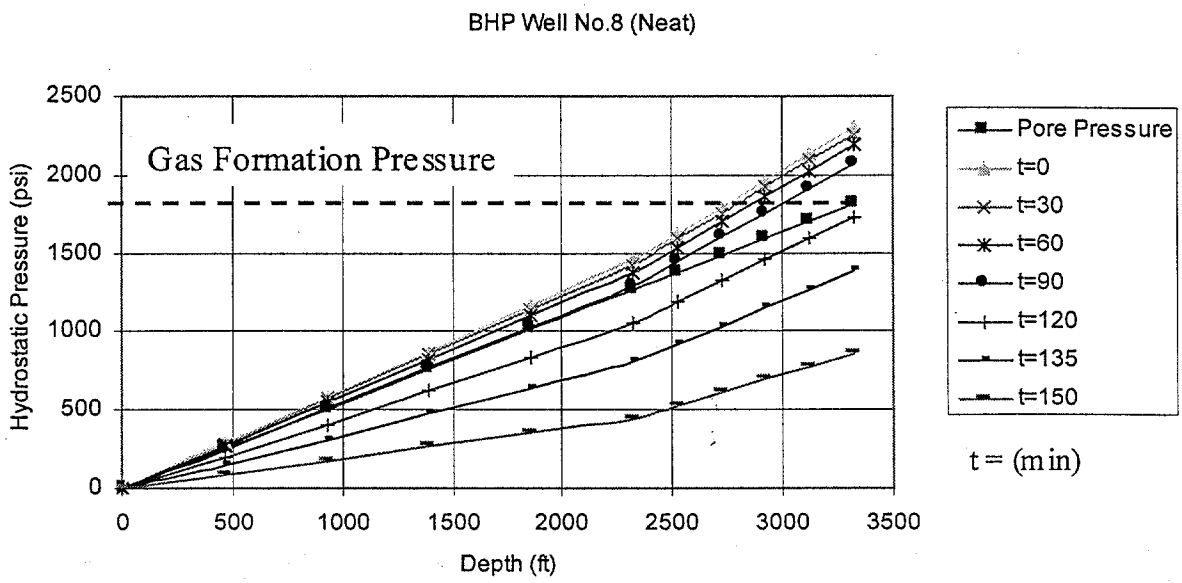
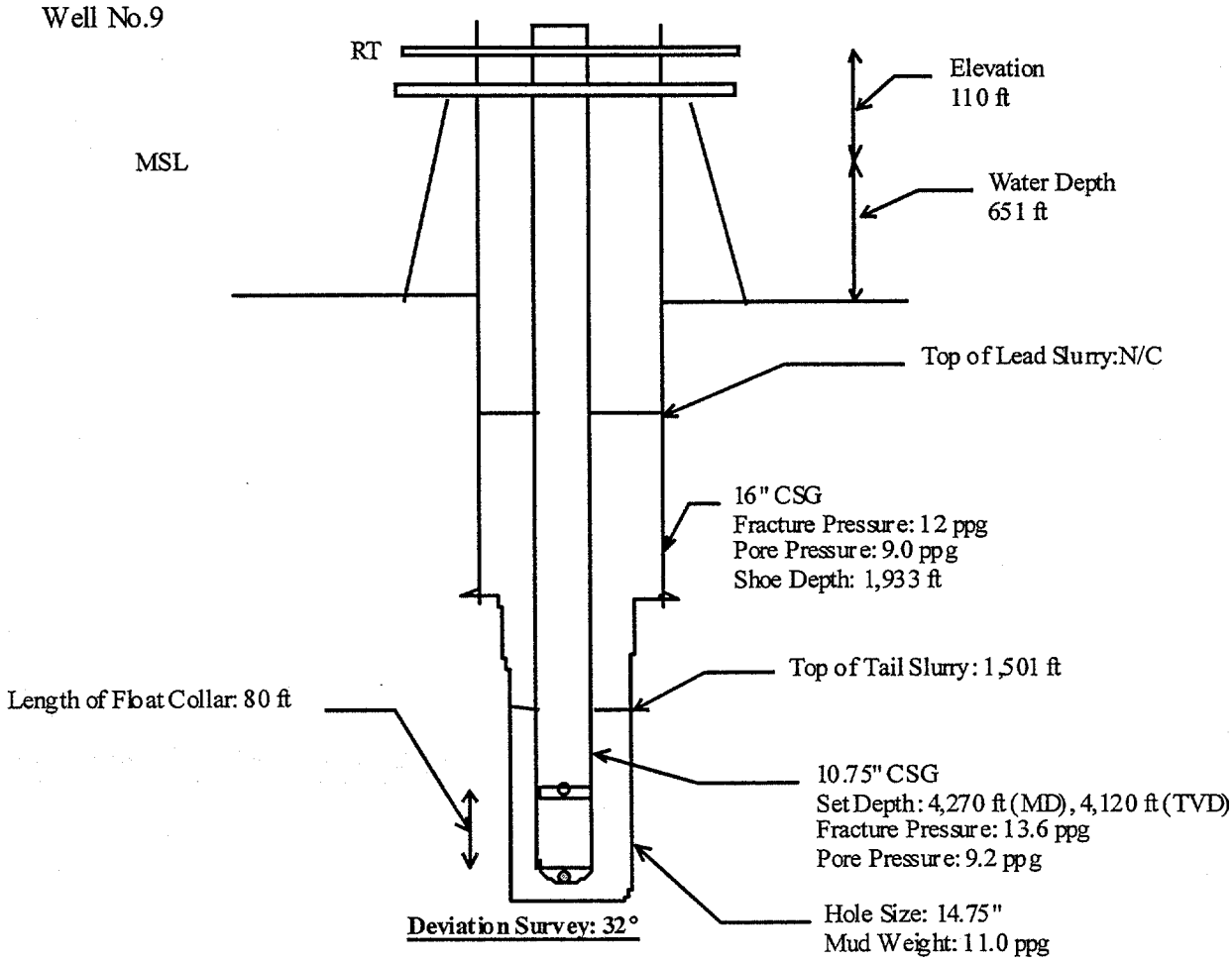


Figure 2.10

Well No.9



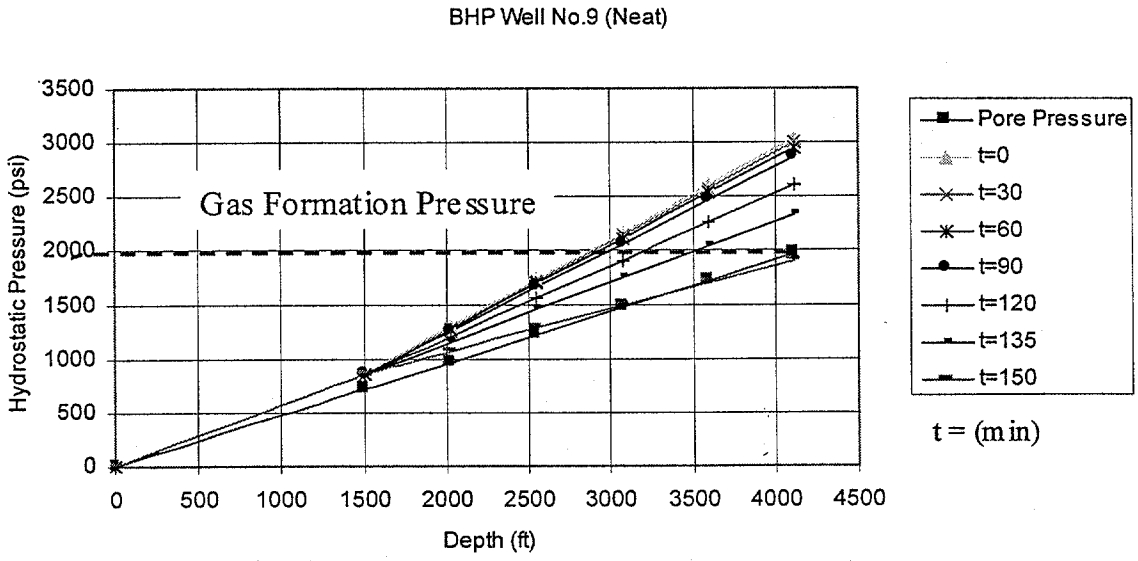
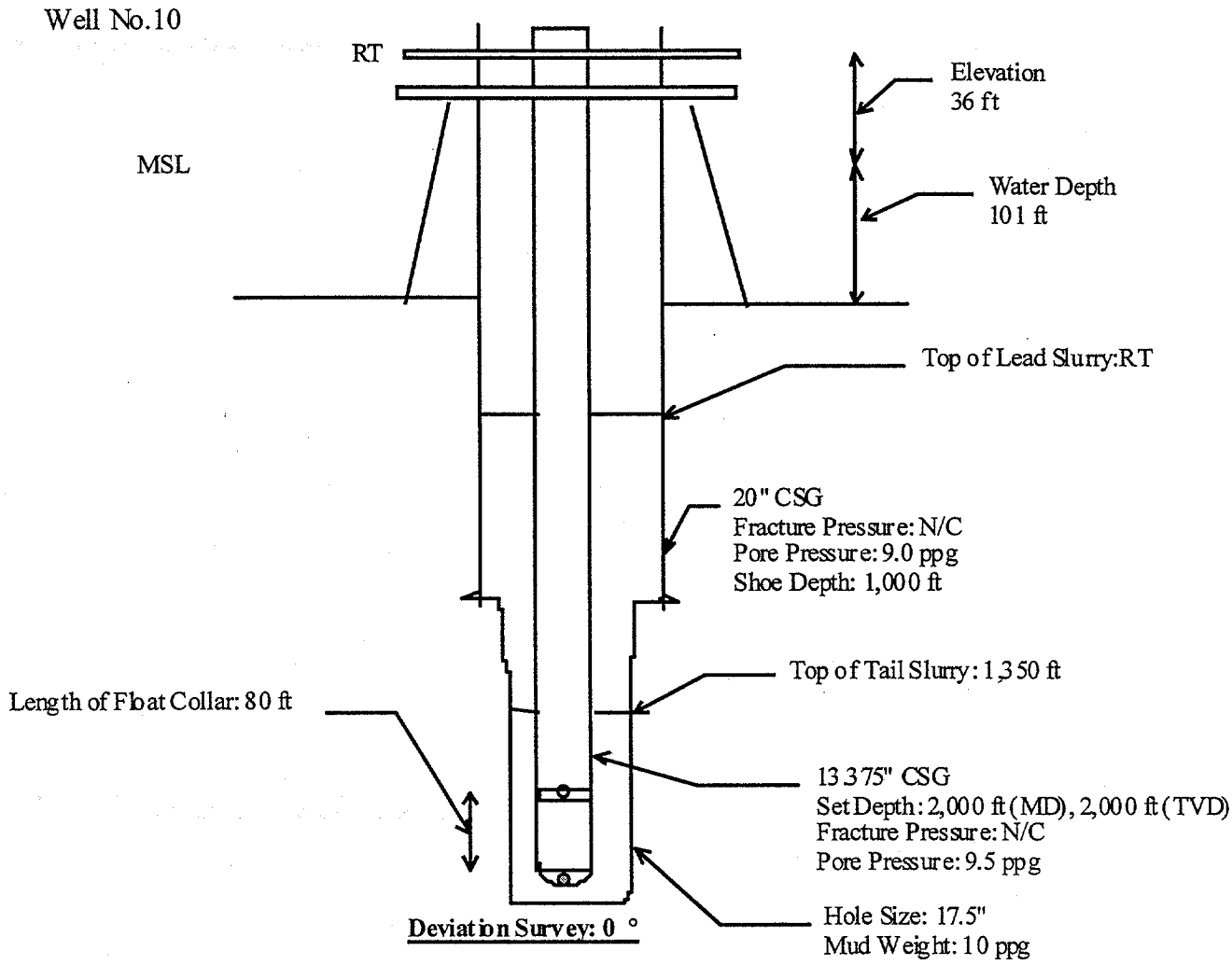


Figure 2.11


Well No.10
RT
MSL
Elevation
36 ft
Water Depth
101 ft
Top of Lead Slurry:RT
20" CSG
Fracture Pressure: N/C
Pore Pressure: 9.0 ppg
Shoe Depth: 1,000 ft
Top of Tail Slurry: 1,350 ft
Length of Float Collar: 80 ft
13 375" CSG
Set Depth: 2,000 ft (MD), 2,000 ft (TVD)
Fracture Pressure: N/C
Pore Pressure: 9.5 ppg
Deviation Survey: 0 °
Hole Size: 17.5"
Mud Weight: 10 ppg

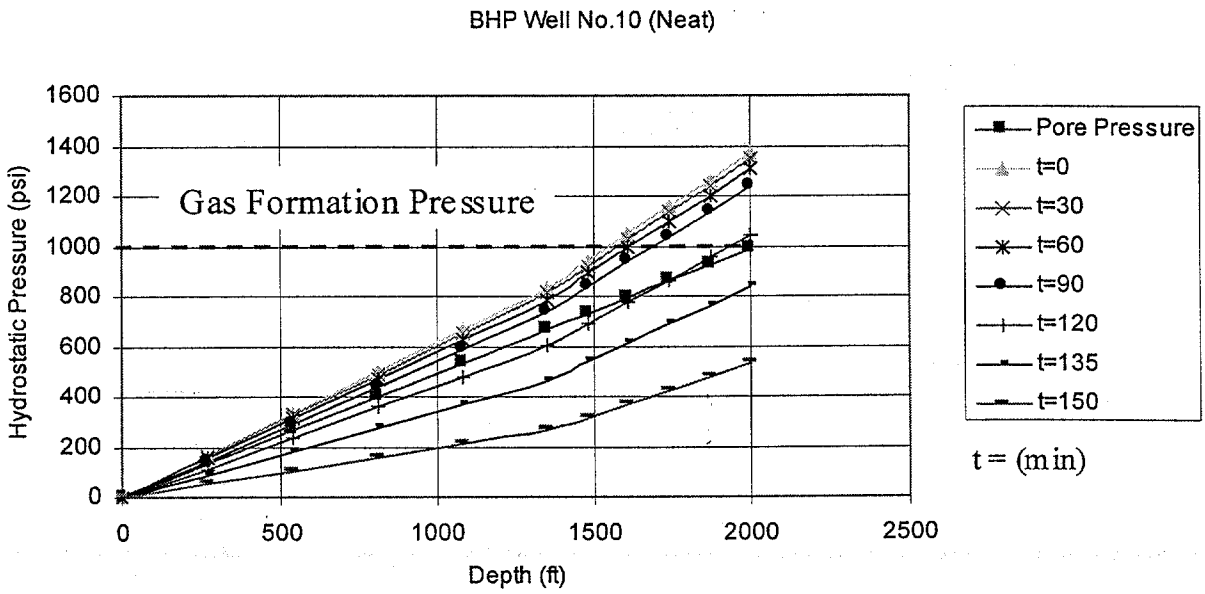
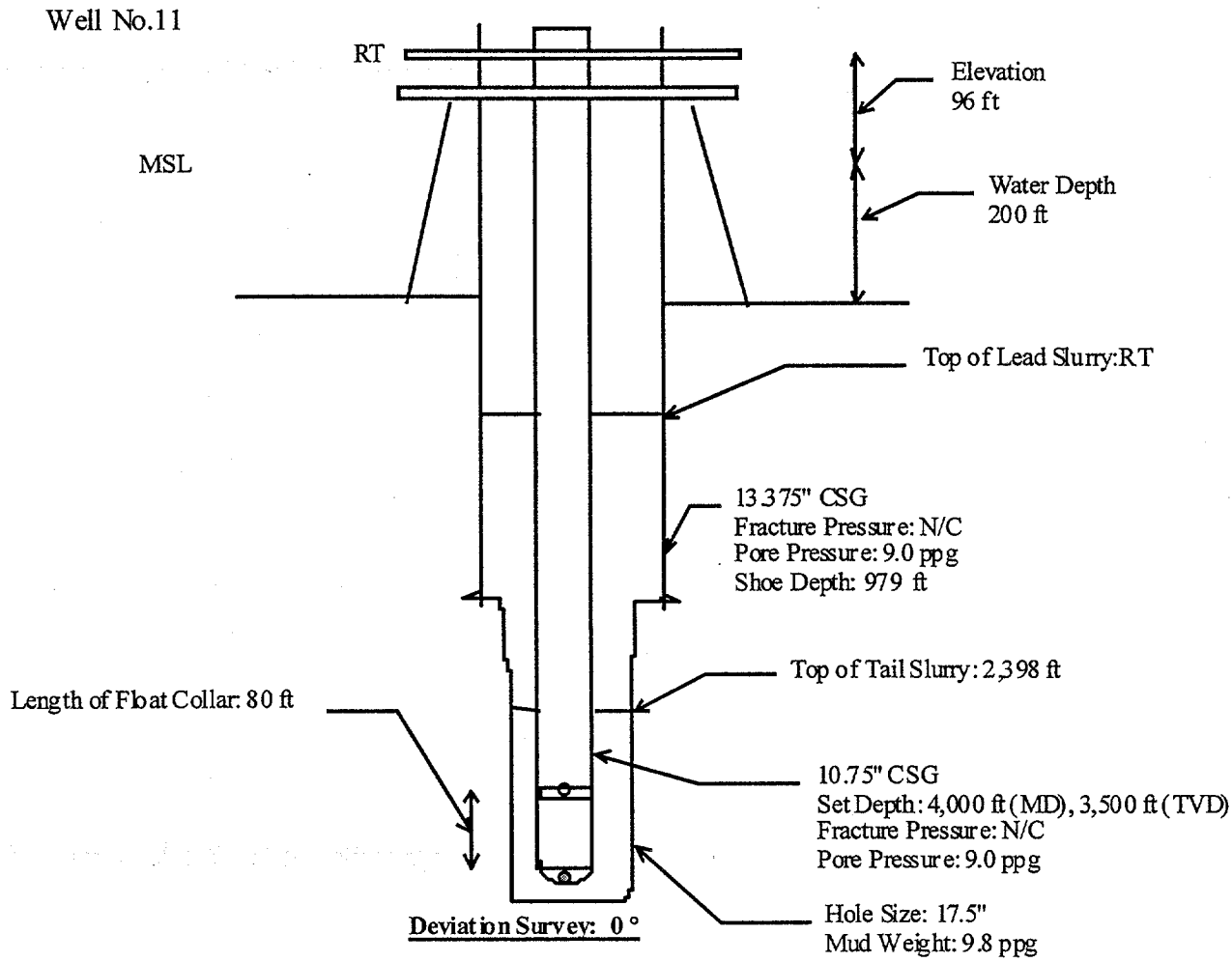

BHP Well No.10 (Neat)
Gas Formation Pressure
Hydrostatic Pressure (psi)
Depth (ft)
0
200
400
600
800
1000
1200
1400
1600
0
500
1000
1500
2000
2500
Pore Pressure
t=0
t=30
t=60
t=90
t=120
t=135
t=150
t = (min)

Figure 2.12


Well No.11
RT
MSL
Elevation
96 ft
Water Depth
200 ft
Top of Lead Slurry:RT
13.375" CSG
Fracture Pressure: N/C
Pore Pressure: 9.0 ppg
Shoe Depth: 979 ft
Top of Tail Slurry: 2,398 ft
Length of Float Collar: 80 ft
10.75" CSG
Set Depth: 4,000 ft (MD), 3,500 ft (TVD)
Fracture Pressure: N/C
Pore Pressure: 9.0 ppg
Deviation Survey: 0 °
Hole Size: 17.5"
Mud Weight: 9.8 ppg

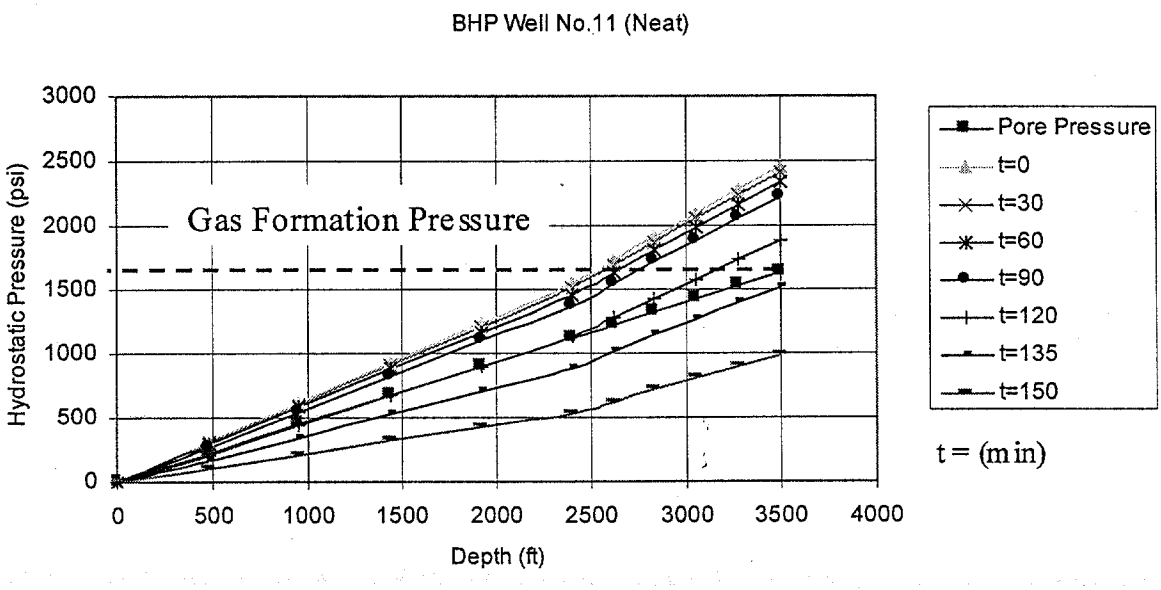
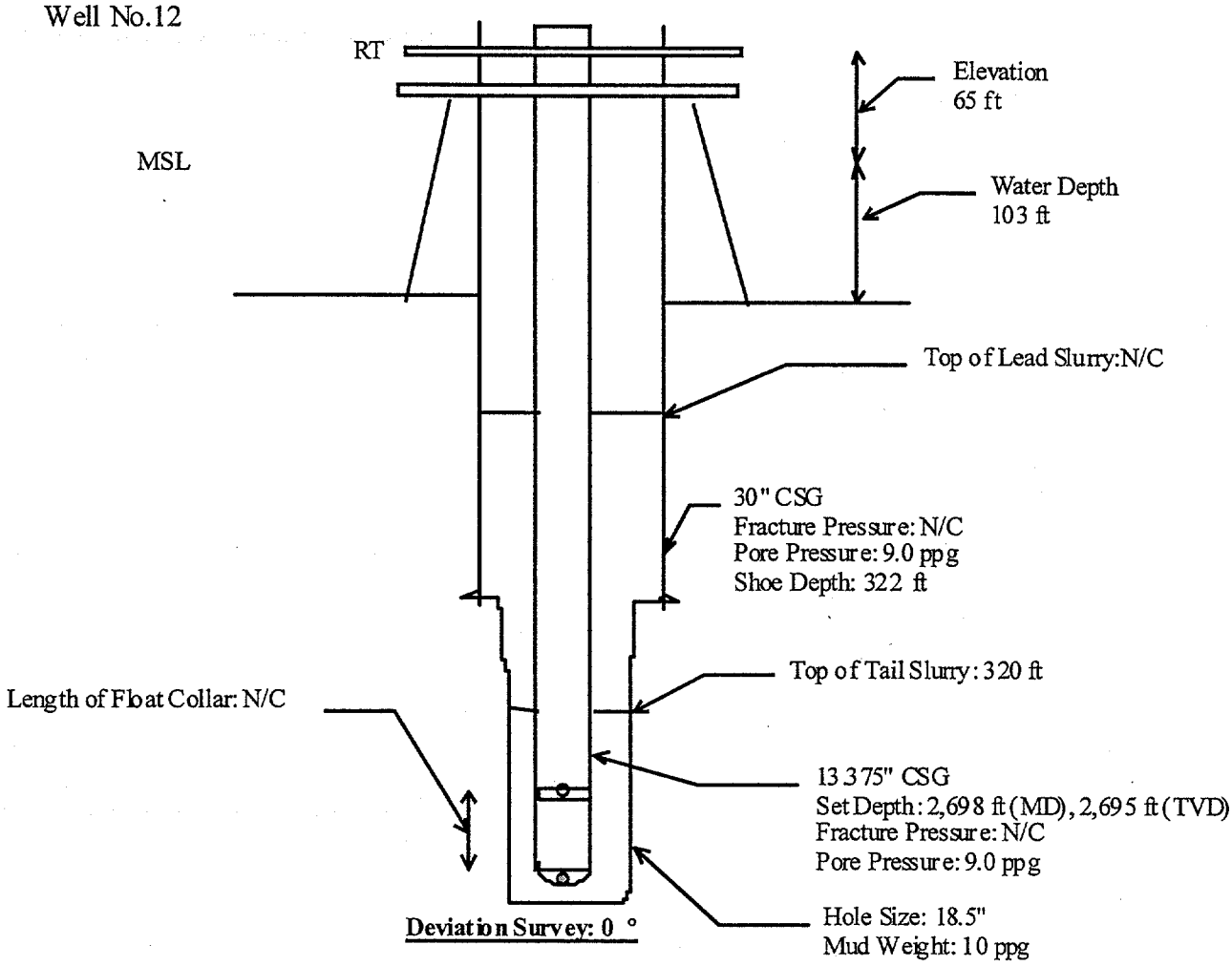

BHP Well No.11 (Neat)
Hydrostatic Pressure (psi)
Depth (ft)
Gas Formation Pressure
0
500
1000
1500
2000
2500
3000
3500
4000
Pore Pressure
t=0
t=30
t=60
t=90
t=120
t=135
t=150
t = (min)

Figure 2.13

Well No.12



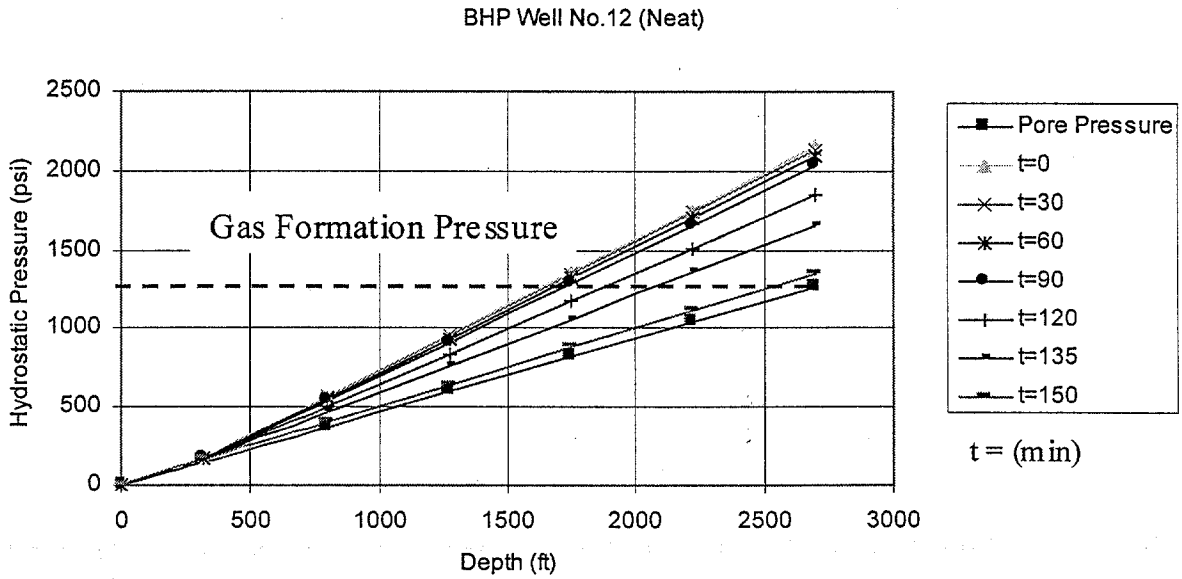
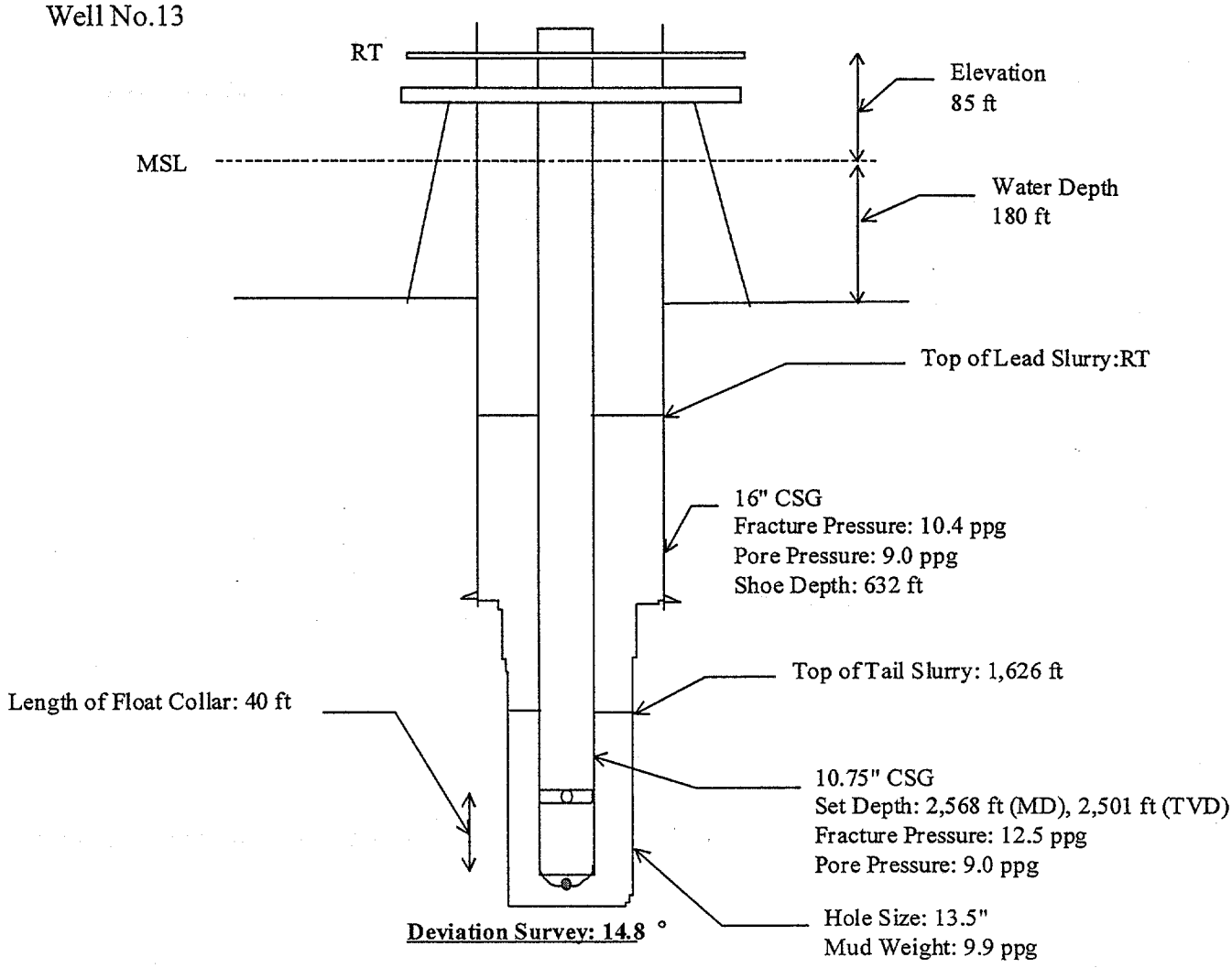


Figure 2.14

Well No.13



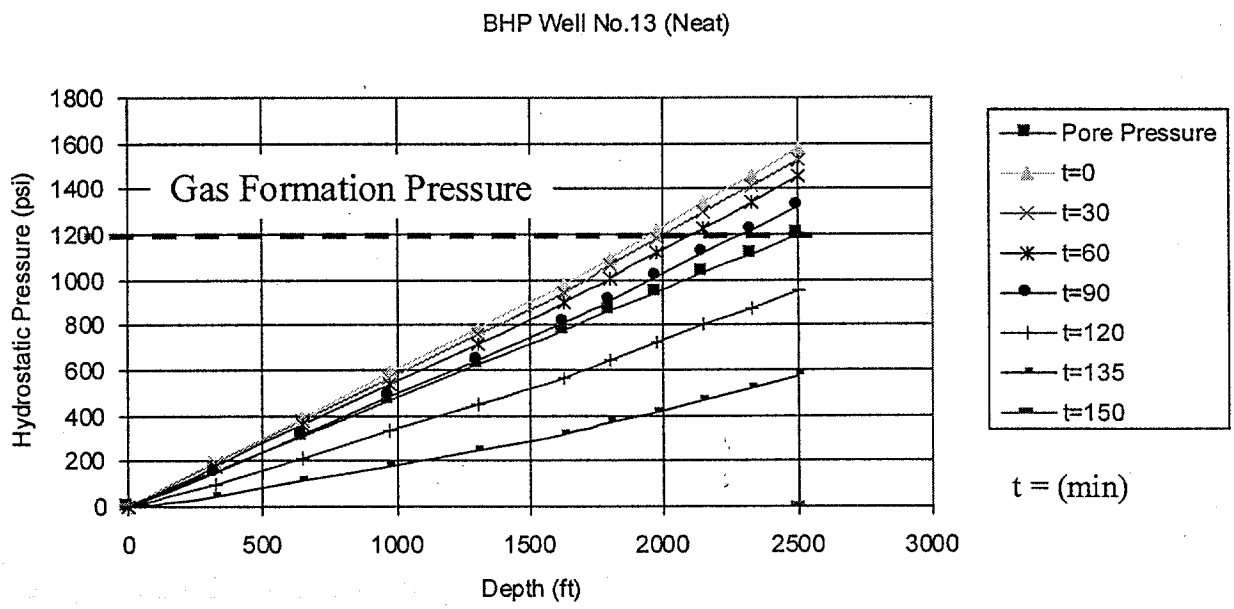
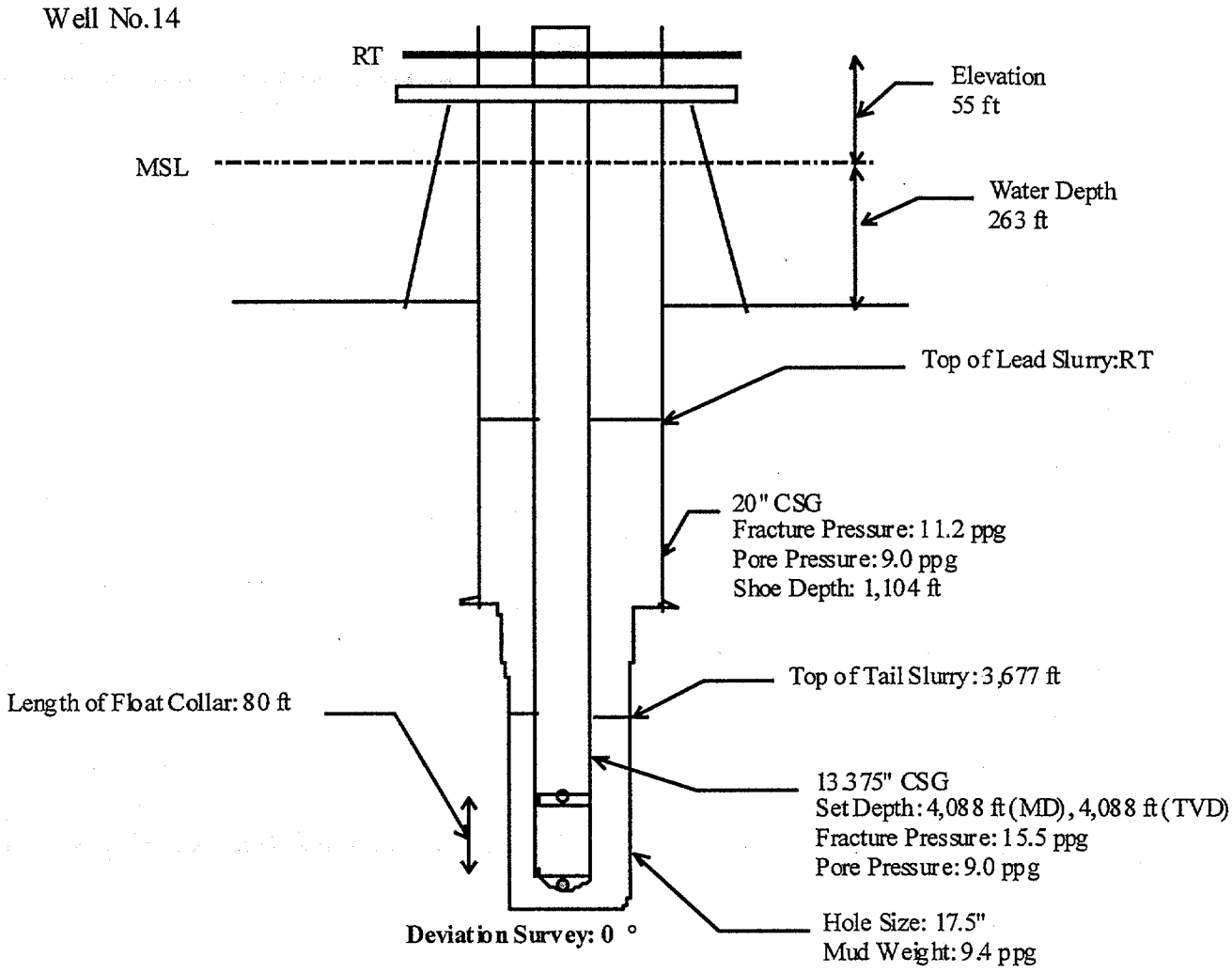


Figure 2.15

Well No.14



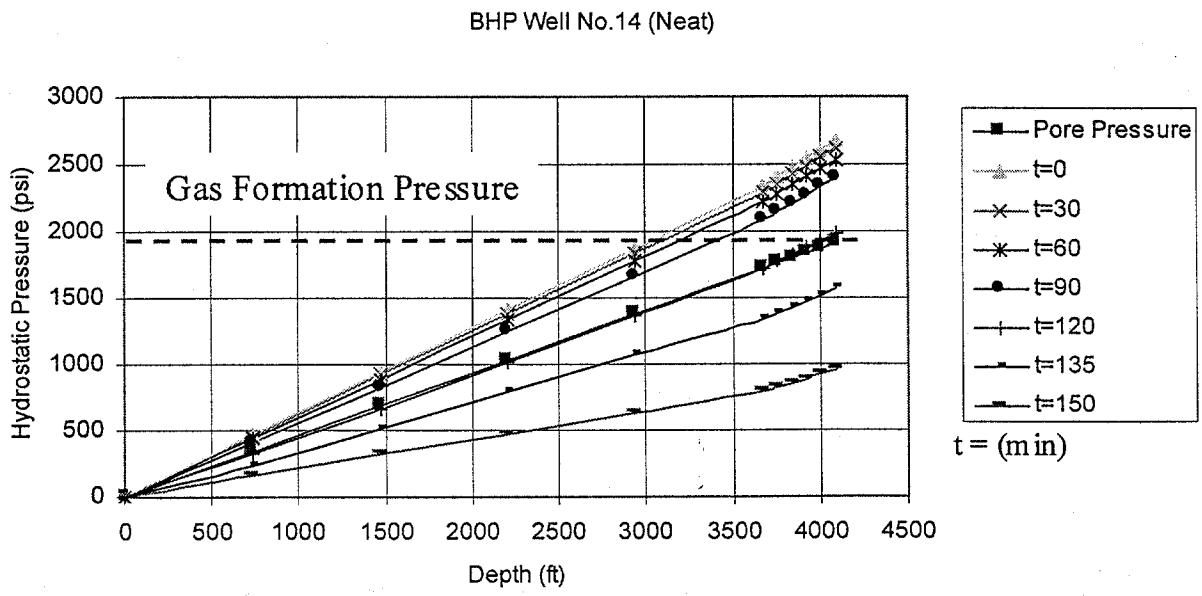
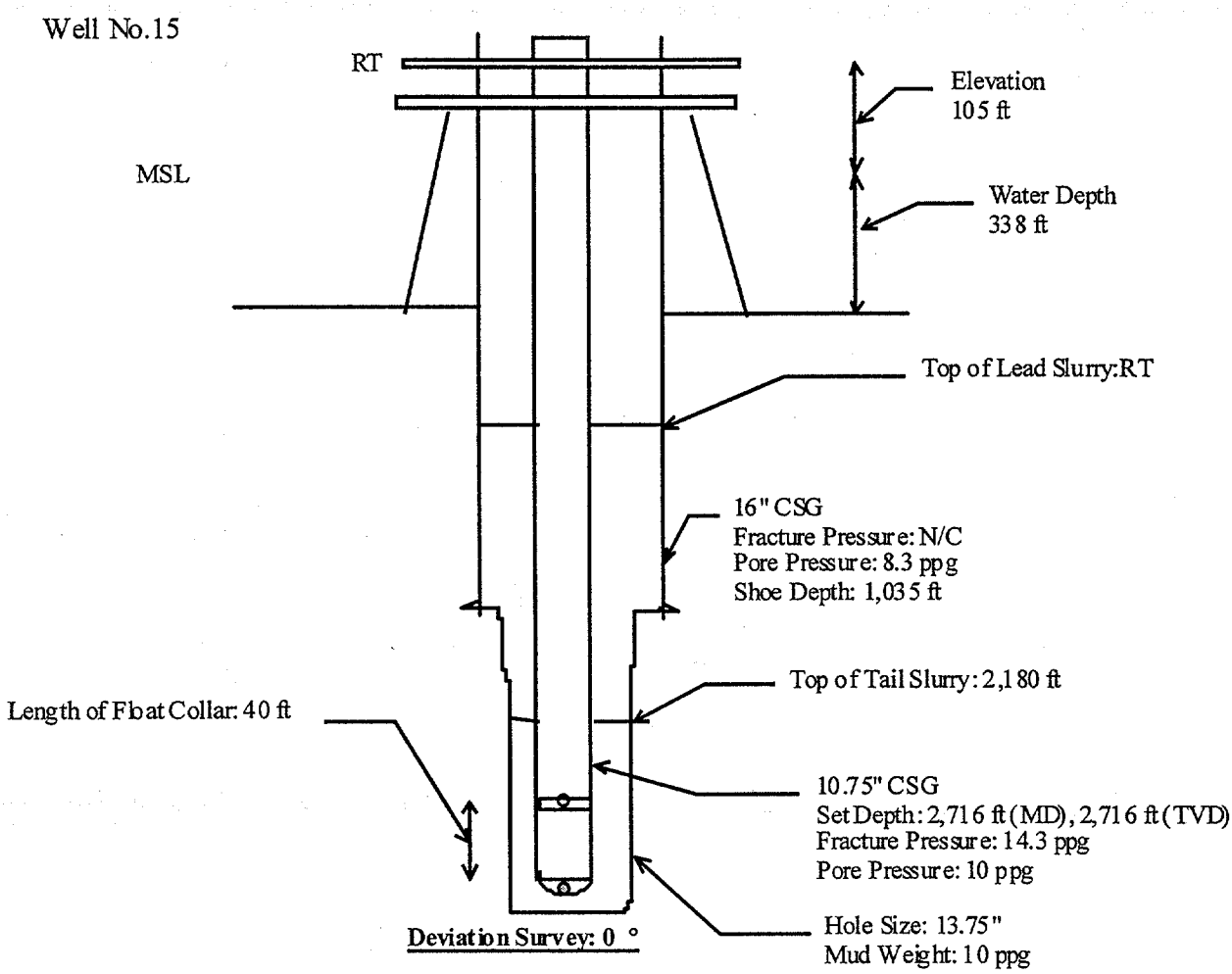


Figure 2.16

Well No.15



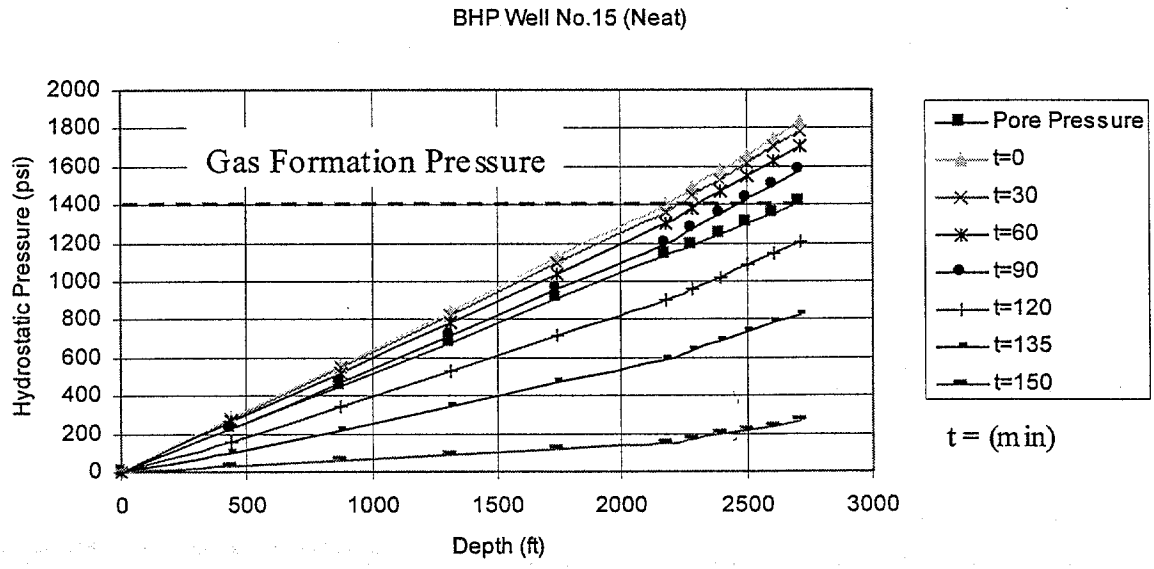
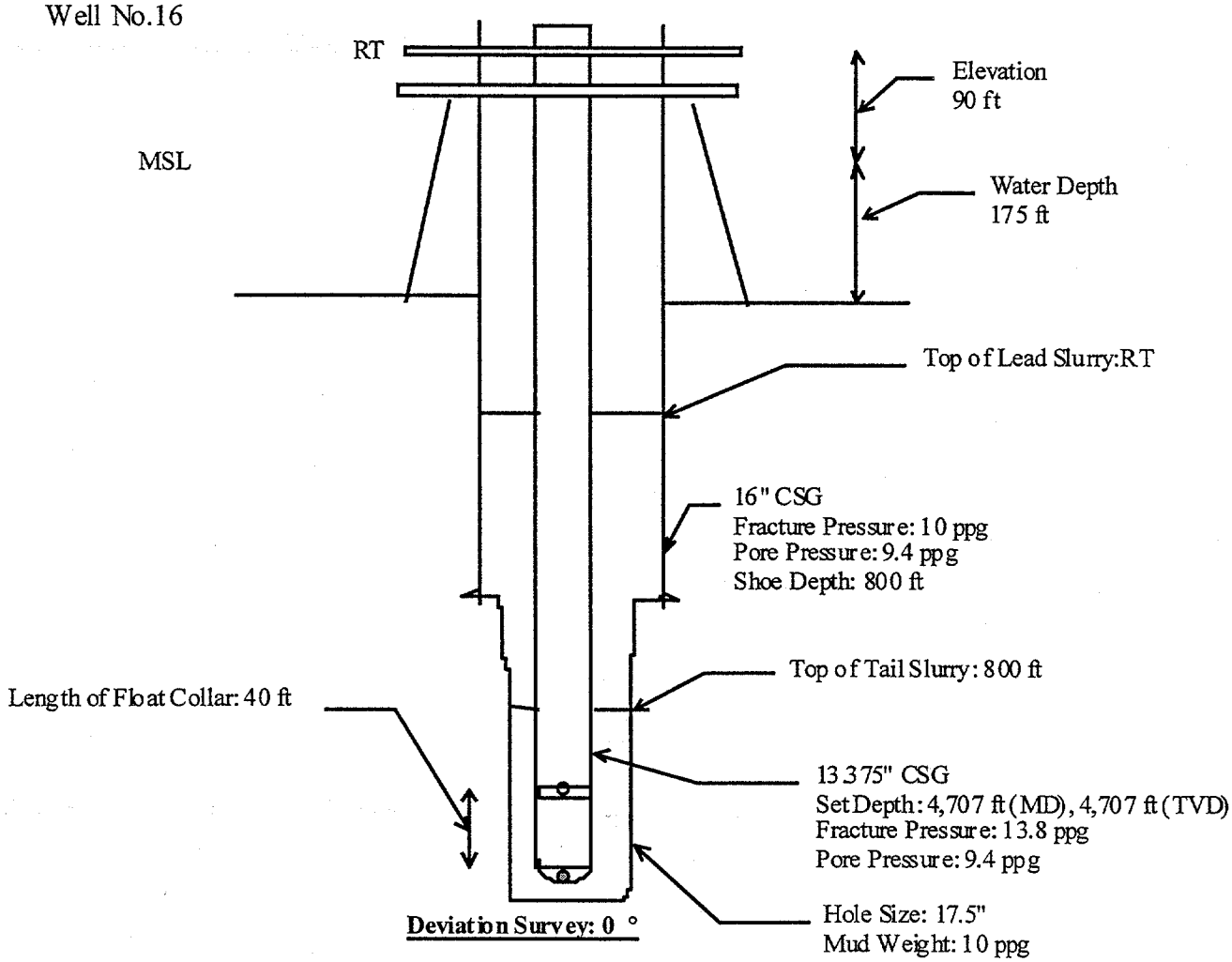
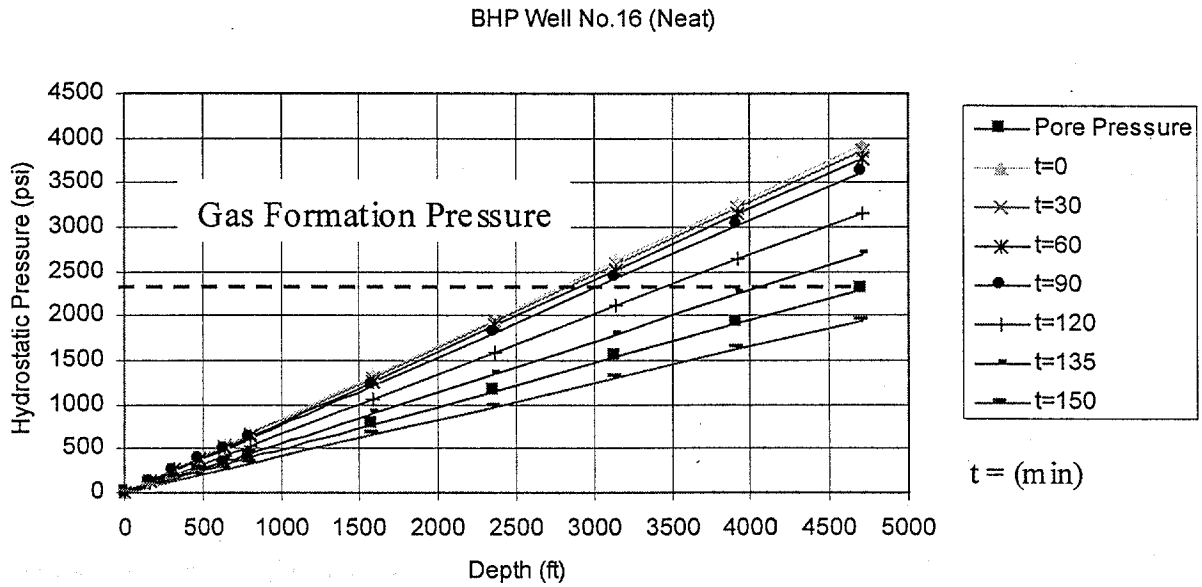


Figure 2.17

Well No.16





Attachment 1. Well Data (No.1 - No.16)

No.	Elevation Data		Last CSG					Hole Data			Running Casing							Cement Data			
	ED	WD	OD	ID	Shoe	Pressure Data		Bit	MW	DS	Size	Set Depth				Pressure Data		Lead		Tail	
						Frac.	Pore	Size			OD	ID	MD	TVD	LFC	Frac.	Pore	Volume	WT	Volume	WT
	(ft)	(ft)	(in)	(in)	(ft)	(ppg)	(ppg)	(in)	(ppg)	(dgr)	(in)	(in)	(ft)	(ft)	(ft)	(ppg)	(ppg)	(cf)	(ppg)	(cf)	(ppg)
1	100	70	16	*15.124*	1000	11.4	9	14.75	9.2	35	10.75	*9.85*	4045	3940	40	14.4	9	3509	11.7	603	16.4
2	190	90	20	*19*	1105	10.8	9	17.5	9.2	0	13.375	*12.515*	4780	4780	40	14.8	9	4211	11.9	2184	16.4
3	125	194	16	*15.124*	1013	12	9.5	14.75	11	0	10.75	*9.85*	4550	4550	60	15.1	9.5	2944	12	650	16.4
4	97	236	20	*19*	1243	12.8	9	20	11	0	16	*15.124*	3991	3991	40	14.9	9	3588	11.4	1387	16.2
5	161	209	24	*23.82*	530	11.7	8.4	22	9	23.7	16	*15.124*	829	826	40	12.2	8.4	1178	12	292	16.2
6	100	209	20	*19*	1000	11	9	17.5	9.5	0	13.375	*12.515*	5462	5462	40	15.3	9.2	5738	11.4	654	16.2
7	100	-	18.625	*17.755*	1335	11	9	17.5	10	45.5	13.375	*12.515*	1386	1386	80	14.1	9.5	3178	12.6	943	16.2
8	99	398	26	*24.6*	1414	12.3	9	24	11	0	20	*19*	3326	2236	40	15.5	10.5	3690	12.2	1044	16.4
9	110	651	16	*15.124*	1933	12	9	14.75	11	32	10.75	*9.85*	4270	4120	80	13.6	9.2	-	12.6	1575	16.2
10	36	101	20	*19*	1000	-	9	17.5	10	0	13.375	*12.515*	2000	2000	80	-	9.5	1950	12	520	16.2
11	96	200	20	*19*	979	-	9	17.5	9.8	0	13.375	*12.515*	4000	3500	80	-	9	3178	12.5	943	16.2
12	65	103	30	*28.05*	322	-	9	18.5	10	0	13.375	*12.515*	2698	2698	0	-	9	0	12.6	2124	15.6
13	85	180	16	*15.124*	632	10.4	9	13.5	9.9	14.8	10.75	*9.85*	2568	2501	40	12.5	9.2	1030	11.8	348	13.4
14	55	263	20	*19*	1104	11.2	9	17.5	9.4	0	13.375	*12.515*	4088	4088	80	15.5	9	4536	12.4	354	15.6
15	105	338	16	*15.124*	1035	-	8.3	13.75	10	0	10.75	*9.85*	2716	2716	40	14.3	10	2016	12.6	236	15.6
16	90	175	16	*15.124*	800	10	9.4	17.5	10	0	13.375	*12.515*	4707	4707	40	13.8	9.4	0	16.2	4461	16.2

OILWELL CEMENT PULSING TO MAINTAIN HYDROSTATIC PRESSURE- A DESIGN MODEL

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ABSTRACT

Presented are theoretical and experimental results from a project supporting development of a new method for cement vibration in well's annulus to prevent gas migration. In this method, cyclic pressure pulses are applied at the wellhead and transmitted down the annulus. These pulses cause reciprocation and shear within cement column- a process delaying the loss of hydrostatic pressure and preventing the inflow of gas into the well's annulus.

Field tests in real wells conducted to observe transmission of a single pressure pulse and to measure compressibility of setting cement showed that application of pressure pulses of 100 psi amplitude and 0.1 Hz frequency may be an effective and inexpensive way of preventing gas flow after cementing.

The paper presents development of a cement pulsation design method based upon the analytical model of pressure propagation in Bingham plastic fluid and experimental data on rheology of cement slurries subjected to continuous shear. The primary objective of the method is to minimize the likelihood of gas invasion into the cement-filled annulus.

INTRODUCTION

Top Cement Pulsation (TCP) is a new technique that can be an effective and inexpensive method of prevention of flow after cementing. It has been successfully field tested and is presently used to improve Cement Bond Log. In TCP, pressure pulses of frequency 0.1 Hz and amplitude 100 psi are applied to the sealed annulus. Because cement slurry is a slightly compressible fluid, it contracts a little upon the application of the 100 psi pressure. Cement columns can reach 10,000 ft and more, so the total displacement of cement top due to the 100 psi pressure applied at the top can be quite substantial. This reciprocal motion can be a source of cement shearing which may delay cement slurry gelation. A schematic of the equipment used in TCP is presented in Fig. 1.

Except for connectors and lines, all that is needed for TCP operation is a compressor and a pulse generator. TCP has the following advantages over other methods:

- simple and inexpensive to operate,
- designed to work with cements without expensive additives,
- promotes progressive cement setting from the bottom up.

The objective of this paper is twofold. Firstly, it is to show that TCP can effectively maintain hydrostatic pressure in the cemented annulus. Secondly, the paper shows that TCP can control rheology of cement slurry in such a way that the likelihood of invasion of formation fluids into the annulus is minimized.

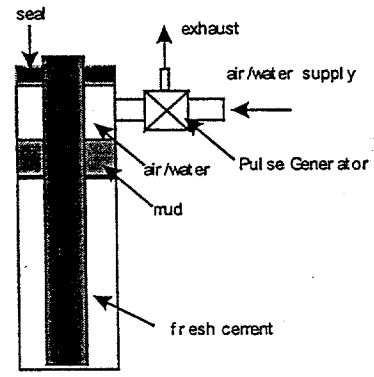

Figure 1 Schematic of the Equipment Used for Top Cement Pulsation, Haberman and Wolhart (1997).

MECHANISM OF HYDROSTATIC PRESSURE MAINTENANCE BY TOP CEMENT PULSATION

Casing vibration as well as reciprocation and rotation have been shown experimentally to delay the loss of hydrostatic pressure and thus minimize transition time of cement slurry (Sutton and Ravi 1991), (Cook et al., 1985). In these experiments a thin layer of fluidized cement slurry around the casing was observed. This layer was considered to provide a hydrostatic head and delay pressure loss. It is expected that reciprocation of cement by TCP will yield a similar effect. One disadvantage of the above methods is that they provide uniform shearing (deformation) along the casing string regardless of depth and do not facilitate cement slurry setting from the bottom up. It was shown that the highest temperature in a well typically is not at the bottom, but one third of the well's depth from the bottom, Raymond (1969). In such an instance, cement may start to set at the depth of maximum temperature and hydrostatic pressure

may not be transmitted below that point. It is, therefore, desirable for gas migration areas to force cement setting from the bottom up.

Laboratory experiments using both steady and oscillatory shearing have been proven as means of breaking gelled structures of static cements within several seconds, (Nonat, 1992), (Chow et al., 1988). A long-term effect of shearing on cement rheology in laboratory environment has not, however, been reported up to date. Since TCP is designed to be applied over a few hours' period, a number of experiments to measure the effect of shearing on cement rheology over a long time have been conducted.

EXPERIMENTAL MEASUREMENT OF OILWELL CEMENT RHEOLOGY

Neat class H oilwell cement slurry at room temperature as well as cement used in an actual TCP field operation were tested. The experiments were conducted in the following manner. Cement was first mixed according to the API Specification 10. Next, its density was measured using a pressurized mud balance. Then cement was poured into the cup and continuously sheared using a Fann 35 viscometer. Two sets of tests were performed. In the first set, rheology of cements used in an actual wellbore was evaluated. In the second, neat cement properties were measured. Since in the wellbore conditions cement is subjected to oscillatory shear and Fann 35 viscometer is capable of providing steady shear only, a procedure of converting oscillatory shear into an equivalent steady shear was used. The governing equation is, (Manowski, 1997):

$$\bar{v} = \frac{\pi}{T} \cdot y \qquad (1)$$

For the Bingham plastic fluid, shear rate at the wall is, (Bourgoyne et al., 1991, p. 144):

$$\dot{\gamma}_w = \frac{6 \cdot \bar{v}}{r_2 - r_1} + \frac{1}{2} \cdot \frac{\tau_y}{\mu_p} \qquad (2)$$

Combining eq.(1) with eq. (2), yields:

$$\dot{\gamma}_w = \frac{12.0}{T} \cdot \frac{\pi \cdot y}{r_2 - r_1} + 3.0 \cdot \frac{\tau_y}{\mu_p} \qquad (3)$$

Equation (3) relates displacement at any depth to constant shearing rate. A procedure of finding displacement amplitude for any depth will be presented later. Let us now focus on the results of the rheological tests. Fig. 2 shows yield point development for a sheared (dotted line) and unsheared (solid line) neat cement sample. It shows that up to about 4 hours, continuous shearing can be a method of maintaining high fluidity of neat cement class H in room temperature. Note that in unsheared cement Static Gel Strength starts to build up rapidly after about 90 minutes. The experiments also showed that continuous shearing at 3 rpm, the lowest speed available with Fann 35, was enough to maintain liquidity of cement sample. In this work shearing rate equivalent to 3 rpm was chosen as the minimum shearing rate to maintain liquidity of cement. This shearing rate did not appear to be a function of time and reached values between 57 and 116 s^{-1} depending on the plastic viscosity and yield point values of cement (Bourgoyne et al., 1991, p. 475).

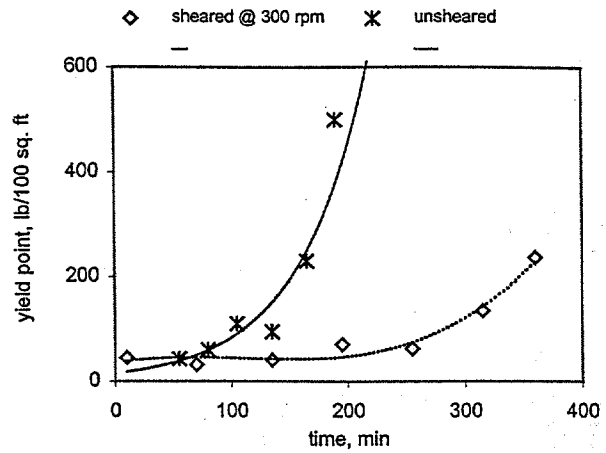

Figure 2 Effect of Shearing on the Development of Yield Point of Class H Oilwell Cement.

It was, then, concluded that as low a shearing rate as 116 s^{-1} may be enough to prevent gelation of setting cement and thus maintain high hydrostatic pressure of cement column.

Rheological tests that produce both yield point and plastic viscosity development in time can provide a basis for the design of TCP operation such that only the upper section of cement in annulus is liquefied while the bottom section remains unsheared and sets rapidly. However, the design of such a "selective" pulsation requires mathematical modeling.

PRESSURE WAVE PROPAGATION IN BINGHAM PLASTIC FLUID

There are a number of reasons why a mathematical model of pressure wave propagation was deemed necessary in this work. They can be summarized as:

- need for the determination of distribution of displacement amplitude with depth: this information is necessary for determination of the depth at which reciprocation does not lead to slurry liquification;
- need for the evaluation of compressibility of the annulus and cement and its effect on pressure pulse propagation: it is the cement compressibility and borehole wall expansion that provides movement of the column; since that movement is critical in this technology, it is desirable to estimate what and how borehole rock and cement properties affect pressure pulse transmission;
- need for the prediction of the displacement of the top of cement in time: it is important to see how pressure pulse needs to be adjusted to meet design objectives;

- need for the evaluation of adverse effects that TCP might have on borehole stability.

The mathematical model was based on a momentum equation for the borehole annulus filled with Bingham plastic fluid. The reason for using Bingham plastic rheological model was its simpicity together with reasonable accuracy for cement slurries. (Herschel-Bulkley model may be slightly more accurate but it leads to non-linear equations which are much more difficult to solve.) Other rheological models without yield point appeared to be inadequate. Bingham plastic model by itself is not a time-dependent model. Both plastic viscosity and yield point, however, can be expressed as functions of time, thus producing time dependence in this model.

The following assumptions were made in the derivation and solution of the momentum equation:

- cement moves as a plug,
- there is a sharp interface between cement and displacing fluid (gas or water),
- any effects of gas or water diluted or trapped or mixed with cement as a result of pulsations are ignored,
- cement density is constant

The momentum equation combined with the material balance equation for Bingham plastic fluid is:

$$\frac{\partial^2 y}{\partial t^2} - s^2 \cdot \frac{\partial^2 y}{\partial z^2} + \frac{12 \cdot \mu_p}{\rho \cdot (r_2 - r_1)^2} \cdot \frac{\partial y}{\partial t} + \frac{3 \cdot \tau_y}{\rho \cdot (r_2 - r_1)} - g = 0 \qquad (4)$$

Solution of this equation is in complex space. The real portion of the solution is, (Manowski, 1997):

$$y = y_o \cdot e^{-\beta z} \cdot \cos(\alpha \cdot z - \omega \cdot t) + \frac{1}{2} \cdot \frac{z^2}{s^2} \cdot \left(\frac{3 \cdot \tau_y}{\rho \cdot (r_2 - r_1)} - g \right) \qquad (5)$$

where:

$$\alpha = \sqrt{\frac{\omega}{s^2} \cdot \sqrt{\left(\frac{12 \cdot \mu_p}{\rho \cdot (r_2 - r_1)^2} \right)^2 + \omega^2}} \cdot \cos\left(\frac{\phi}{2}\right) \qquad (5a)$$

$$\beta = \sqrt{\frac{\omega}{s^2} \cdot \sqrt{\left(\frac{12 \cdot \mu_p}{\rho \cdot (r_2 - r_1)^2} \right)^2 + \omega^2}} \cdot \sin\left(\frac{\phi}{2}\right) \qquad (5b)$$

$$\phi = \arctan\left(\frac{12 \cdot \mu_p}{\rho \cdot \omega \cdot (r_2 - r_1)^2} \right) \qquad (5c)$$

Upon the examination of the first component of eq. (5), we can notice that for the depth z=0 and for time increasing from 0 to the half period of pulsations (5 sec), the value of the cosine will decrease from 1 to 0. It means that downward displacement is negative and upward displacement is positive, as measured from the initial position.

Equation (5) describes displacement y of cement particles whose initial position is z. Note that this equation is invalid when the wave is reflected from the bottom. Equation (5) implies that for the small value of the argument β and for increasing depth z, the effect of yield point on displacement amplitude is stronger than that of plastic viscosity. Also, small cross-sectional area of the annulus promotes stronger attenuation of the pulse.

DOWN HOLE PRESSURE PREDICTION

The ability of the theoretical model to predict downhole pressure is important for the application of TCP as it may offer an insight into the effectiveness of the technology. Pressure can be measured more conveniently and accurately than displacement. And monitoring pressure changes during the application of TCP is a way of assessing the efficiency of TCP.

Pressure at any depth can be combined with displacement y using the following formula (Binder, 1997):

$$\frac{\partial p}{\partial z} = -\rho_o \cdot s^2 \cdot \frac{\partial^2 y}{\partial z^2} \qquad (6)$$

Combing equation (5) with equation (6) and performing suitable differentiation results in:

$$\frac{\partial p}{\partial z} = \rho_o \cdot y_o \cdot e^{-\beta \cdot z} \cdot \omega \cdot \sqrt{\left[\frac{12 \cdot \mu_p}{\rho \cdot (r_2 - r_1)^2} \right]^2 + \omega^2} \cdot \left[\cos(\alpha \cdot z - \omega \cdot t) \cdot \cos\phi - \sin(\alpha \cdot z - \omega \cdot t) \cdot \sin\phi \right] - \rho_o \cdot \frac{3 \cdot \tau_y}{\rho \cdot (r_2 - r_1)} + \rho_o \cdot g \qquad (7)$$

Pressure at any depth can then be computed after integration of the equation (7) from the top of the cement (z=0) to a given depth z=Z:

$$P = \rho_o \cdot y_o \cdot s^2 \cdot \{ \cos\phi \cdot [e^{-\beta \cdot Z} \cdot \{ \alpha \cdot \sin(\alpha \cdot Z - \omega \cdot t) - \beta \cdot \cos(\alpha \cdot Z - \omega \cdot t) \} + \alpha \cdot \sin(\omega \cdot t) + \beta \cdot \cos(\omega \cdot t)] + \sin\phi \cdot [e^{-\beta Z} \cdot \{ \beta \cdot \sin(\alpha \cdot Z - \omega \cdot t) + \alpha \cdot \cos(\alpha \cdot Z - \omega \cdot t) \}$$

$$+\alpha\cdot\cos(\omega\cdot t)+\beta\cdot\sin(\omega\cdot t)]\}-\rho_o\cdot\frac{3\cdot\tau_y}{\rho\cdot(r_2-r_1)}\cdot Z$$

$$+\rho_o\cdot g\cdot Z \qquad (8)$$

CEMENT COMPRESSIBILITY MEASUREMENTS AND EFFECT OF CEMENT COMPRESSIBILITY ON PRESSURE WAVE PROPAGATION

Since cement compressibility controls both displacement amplitude and wave propagation characteristics, it is desirable to find how it changes in time. Specifically, what is the effect of chemical hydration on cement compressibility. The relationship between cement compressibility and wave propagation velocity is, (Streeter & Wylie, 1967):

$$s=\sqrt{\frac{E_{R/C}}{\rho\cdot c_c\cdot E_{R/C}+2\rho\cdot(1+\nu)}} \qquad (9)$$

Equation (9) is valid for an elastic wall forming a circular tunnel. Elastic modulus in this equation represents the effective elasticity of the borehole and casing. Measurements of cement compressibility were conducted using a high pressure stainless steel vessel. Mercury was injected at controlled volume and pressure. A schematic of the equipment used is presented in Fig. 3.

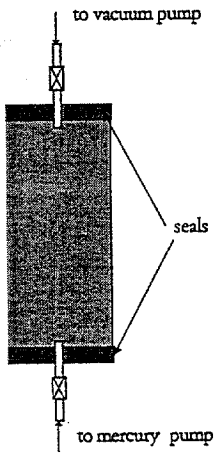

Figure 3 Cement Compressibility Test Cell.

The procedure used was as follows. Cement slurry was mixed according to API Specification 10 and de-aerated using a vacuum pump. Then it was poured into the vessel and a mercury line was attached to the bottom connector of the vessel. With the top valve open, mercury was slowly injected from the bottom in order to displace all air trapped at the top.

Once only cement slurry was flowing over the top valve, mercury pump was stopped and the top valve was closed. Then mercury was slowly injected into the vessel. Volume of the injected mercury as well as mercury pressure were recorded. Figure 4 presents combined results of cement compressibility measurements for the case of retarded class H cement slurry. Note high compressibility at low pressures. This is caused probably by air trapped within cement slurry despite the use of vacuum pump to de-aerate the slurry. This graph shows little variation of cement compressibility over the test period. The result implies that the compressibility of the products of chemical reactions is of the same magnitude as the compressibility of the components. Assuming that rock mechanical properties as well as cement density is constant, propagation velocity of traveling wave can be considered as independent of cement slurry properties. Note that this velocity will not be constant, however, in the whole annulus. In the cased portion of the annulus propagation velocity will be considerably greater than in the open hole annulus. Also, if the open hole section is built of different rocks having different mechanical properties, this acoustic velocity will vary.

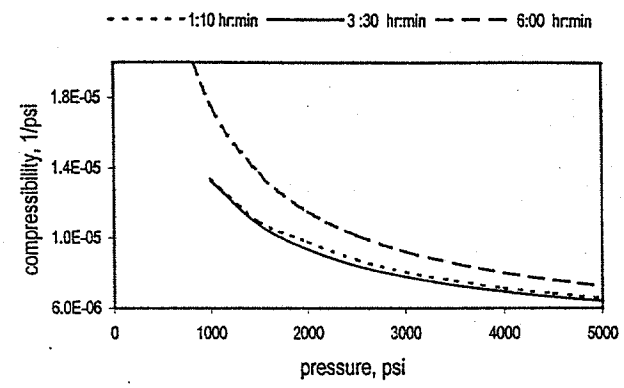

Figure 4 Variation of Compressibility of Cement Class H with Retarder.

VERIFICATION OF THE TOP CEMENT PULSATION MODEL WITH FIELD DATA

Utilizing eq. (5) as well as experimental data on cement rheology and compressibility, displacement of cement column from the known top displacement amplitude can be computed. Using either water or gas pulse generators, a procedure for monitoring top displacement was established, (Haberman and Wolhart, 1997). Figure 5 presents some results of top displacement monitoring. Two types of response can be observed. The first response of the well/cement system to TCP is almost constant displacement with respect to time over the monitoring period. According to the eq. (5) this would mean that cement liquidity is maintained over that period. The other curve shows constant decline of the amplitude of displacement. Apparently, TCP was unsuccessful here. This behavior was explained by the rapid dehydration of cement slurry occurred due to the lack to filtrate cake on the wall of the well (the well was drilled with brine) combined with the lack of fluid loss additive in the slurry, (Haberman and Wolhart, 1997).

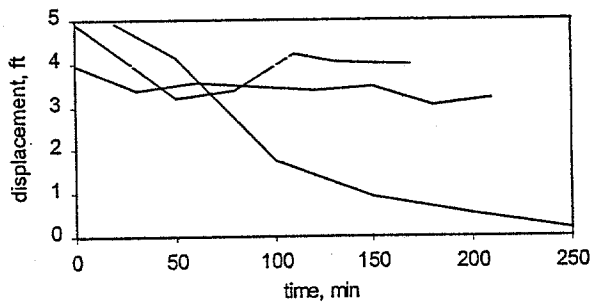

Figure 5 Magnitude of Cement Top Displacement as a Result of Pressure Pulses Applied, Shallow Permian Basin wells.

According to the mathematical model discussed above, there are two possible mechanisms by which the loss of displacement amplitude can be achieved: system compressibility decrease or the volume of cement compressed decrease, (Haberman and Wolhart, 1997). System compressibility is defined here as cement compressibility and borehole expansion. Since, according to the results of experiments, cement compressibility does not change much, only borehole wall expansion component can be responsible for the decline of displacement amplitude. The borehole wall expansion is a function of cement rheology, i.e. pressure pulse attenuation, rock elastic modulus and rock Poisson's ratio. While the rock mechanical properties can be assumed constant, both cement yield point and plastic viscosity increase in time as cement sets. Greater yield point and plastic viscosity will attenuate pressure wave more.

The other explanation implies that as the bottom portion of cement starts to set its compressibility becomes considerably smaller than liquid cement compressibility. In the light of the above experimental results of cement compressibility measurements, this is unlikely to happen during the first few hours of cement hydration. It appears, thus, that the first explanation is more likely to be true.

TOP CEMENT PULSATION DESIGN MODEL

The objective is to design TCP operation so as to selectively minimize transition time of cement and thus minimize the likelihood of gas or water intrusion into cemented column. At the same time, hydrostatic pressure exerted by the reciprocated cement column must exceed water or gas zone pore pressure. Thus, there are two design criteria for this method: selective minimization of cement transition time and bottomhole pressure maintenance.

The theoretical basis for this method is derived for the rapid hydration period of cement. This period is specific for a slurry at given pressure and temperature conditions.

Selective Minimization of Cement Transition Time

This technique can be used to minimize transition time of cement slurry for a given, minimum volume of cement in the wellbore at given time. For this technique to be feasible, we need an estimate of time at which tail cement starts to set at the bottom as well as when lead cement starts to thicken at the top. These estimates can be obtained from cement consistometer test as time to reach 70 units of consistency. This time, commonly referred to as cement "thickening time", is routinely evaluated in service companies' laboratories. Then the rate of cement thickening in the well computed as the ratio of the depth of the well divided by the difference between these two times can be computed. Beginning from the time when cement starts to set at the bottom, we decrease pressure pulse applied at the top in such a way that the depth to which this pressure wave can reach will decrease precisely at the rate equal to the cement setting rate computed earlier. All the cement that is below that depth is allowed to set while all the cement above is being reciprocated, thus it exerts high hydrostatic pressure. Let us assume that at a certain time pressure wave is allowed to reach top of the rectangle marked V_1 - see Fig. 6.

Volume V_1 is left undisturbed and sets freely at the $time_1$. If there is a gas or water zone opposite the volume V_1, it will not be allowed to flow into the setting cement during the transition time of volume V_1 because high hydrostatic pressure Similarily, by the time the subsequent volumes V_2 and V_3 advance into the transition phase and hinder the transmission of hydrostatic pressure, volume V_1 will have already developed enough mechanical resistance to seal the zone hydraulically.

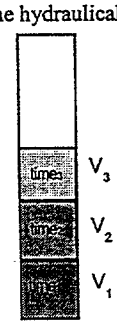

Figure 6 Selective Minimization of Cement Slurry Transition Time, $time_1<time_2<time_3$.

It is therefore important that this cement volume which is stopped being reciprocated sets quickly. The only way it can be ensured is to stop reciprocation during the accelerated hydration period after the dormant period. The aforementioned API thickening time test should give us an estimate of this critical time. It is important to stress here that cement reciprocation cannot proceed into the accelerated hydration period because of the set cement compressive strength decline occurring when cement is sheared for too long in that period, (Hartog et al., 1983). Reciprocation must be ceased during the shaded period shown in Fig. 7.

Bottomhole Pressure Maintenance

The first criterion while minimizing transition time, does not guarantee that pressure exerted by cement column will not decrease below the pore pressure of a porous formation at any time. There is a need, thus, to monitor hydrostatic pressure in cement column.

For this criterion to be achievable practically, an estimated depth of the offending zone with its pore pressure should be known.

If at any time hydrostatic pressure exerted by cement column next that zone comes near the pore pressure in the zone, then pressure pulse strength cannot be decreased further as per the 1st criterion, but it needs to be maintained or even increased so that the zone is not allowed to flow into the annulus.

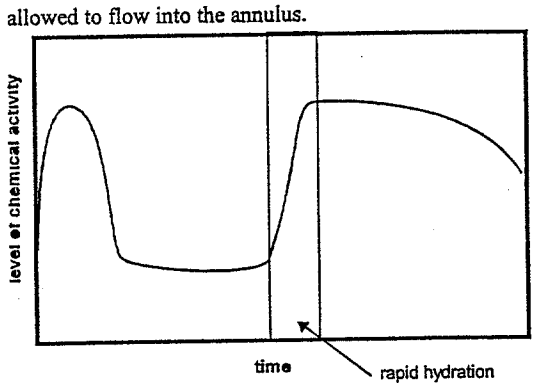

Figure 7 Level of Chemical Activity in Cement as Evidenced by Temperature Changes.

These conditions must be maintained long enough to enable cement next to the formation to set and seal the annulus. The time necessary for cement to set and seal the annulus will depend on specific conditions such as the type of cement used, depth and temperature of the well, etc.

Finally, it should be stressed that there are some cement systems that do not exhibit rapid hydration as shown in Figure 7. Additives used in these systems (not necessarily retarders) slow down hydration, i.e. strength development after the dormant period. Similarly, there are cement systems which hydration period is even more rapid than that of neat cement. Care will have to be exercised with each cement system designed to work with TCP.

CONCLUSIONS

1. Continuous cement shearing can be a means of maintaining low yield point of the slurry and thus preventing hydrostatic pressure loss in reciprocated cement columns.
2. The model of pressure wave propagation in Bingham plastic fluid was developed to assist in design and implementation of Top Cement Pulsation technique.
3. The model shows that the wave is attenuated the most in conditions of small annular clearance and high yield point.
4. Compressibility of cement slurry is high at low pressures probably due to air trapped in the slurry. It does not change, however, during the transition time of the slurry.
5. Decline of top cement displacement amplitude over time should be attributed to the changing rheological and mechanical properties of setting cement slurry.
6. The design of Top Cement Pulsation comprises the selective minimization of transition time criterion and bottomhole pressure maintenance criterion.
7. The design model shows that reciprocation of setting cement slurry can be a powerful technique leading to prevention of flow after cementing.

ACKNOWLEDGMENTS

The authors would like to express their gratitude to John P. Haberman of Texaco Inc. E & P Technology Center and Steve L. Wolhart of the Gas Research Institute for preparation and submission of experimental data and cement samples used in this work. Appreciation is also extended to the Minerals Management Service for funding of this research project.

NOMENCLATURE:

E- modulus of elasticity
c-compressibility
g- acceleration of gravity
p, P- pressure
r-radius
s- acoustic wave velocity
t- time
T- wave period
$\bar{v}$ - average velocity
y-displacement amplitude
z, Z- depth

Greek:
α- parameter
β-parameter
$\dot{\gamma}$ -shear rate
ϕ-parameter
μ-viscosity
ν- Poisson's ratio
ρ- density
τ- shear stress
ω- angular frequency
Subscripts:
1- inner
2- outer
C-casing
R-rock
b- bottom
c-cement
o- initial
p-plastic
y-yield (point)
w-wall

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Flow After Cementing- A New Prevention Method

LSU/MMS

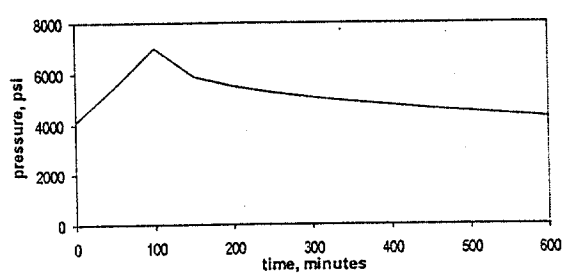
ROTAC Meeting and Well Control Research Status

Wojciech Manowski
Schlumberger Dowell

Andrew K. Wojtanowicz
LSU

Causes of Gas Invasion

- cement column hydrostatic pressure decline:
  - volumetric losses



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

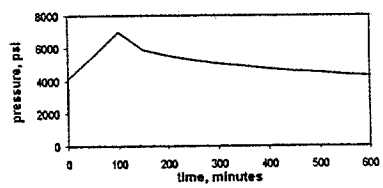
Causes of Gas Invasion

- external volume reduction
- internal volume reduction (chemical shrinkage)
  - cannot be controlled

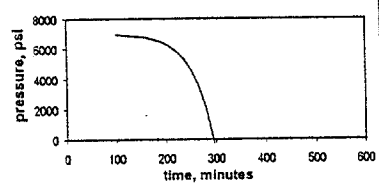
Cement Bottomhole Pressure Models

$$P_z(z,t) = P_{zi} - P_{SGS}$$

- no agreement with field data
- improvements:
  - shear stress formulation, Chenevert & Jin (1989)
  - experimental evaluation of SGS and material balance, Daccord (1992)



Pressure decline, after Cooke (field data)

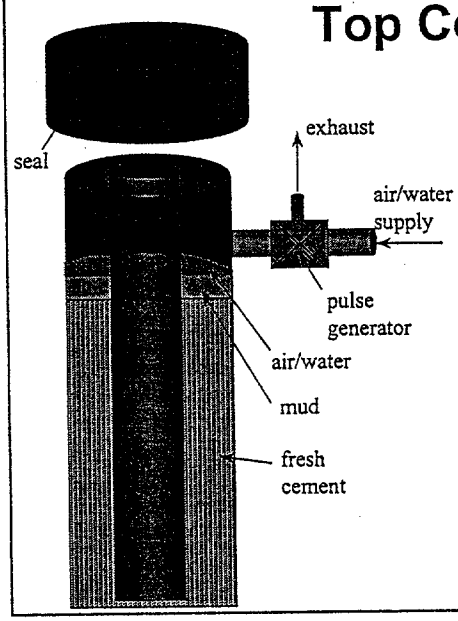


Pressure decline, computed using SGS model

Current Techniques to Prevent Flow after Cementing

- gas migration testing, Cheung & Beirute (1982)
- mechanical and physical techniques:
  - casing vibration, reciprocation and rotation
  - Top Cement Pulsation (TCP)
  - annular back pressure – doesn't work at all
  - external casing packers
- special cements
- technical requirements, good procedures
  - proper density, rheology, flow rate, thickening time, stability, free water, sequence of operations

Top Cement Pulsation



100 psi applied periodically to sealed annulus to prevent loss of hydrostatic pressure and improve the quality of bond

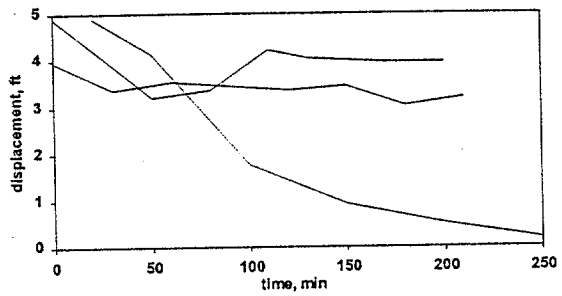
(Haberman & Wolhart, 1997)

Top Cement Pulsation

- improves CBL
- may prevent migration:
  - thin, fluidized layer
  - cement slurry setting progressing from the bottom up
- advantages:
  - simple, inexpensive and easy operation
  - elimination of anti-migration cement additives

Current Status

- operated by monitoring slurry Top Displacement Amplitude in test wells



Cement Top Displacement Amplitude, shallow Permian Basin wells, after Haberman & Wolhart (1997)

Current Status

- hydrostatic pressure response
- "side effects":
  - compressive strength
  - borehole stability
- interpretation of downhole pressure measurement test

⇓

→ need for theoretical study

Top Cement Pulsation Model

- objectives:
  - develop design and execution procedure
- assumptions:
  - cement moves as a plug
  - cement density is constant
  - air diluted in cement neglected

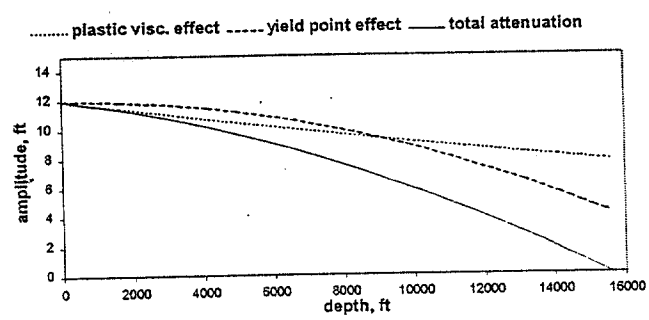
Top Cement Pulsation Model

➢ solution:

displacement= f(top displ., depth, time, cmt properties, wave frequency and acoustic velocity)

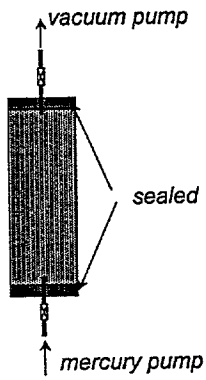
Top Cement Pulsation Model

➔ theoretical effect of cement rheology on pressure pulse propagation:



Theoretical Effect of Plastic Viscosity and Yield Point on Pressure Wave Attenuation in Cement Column

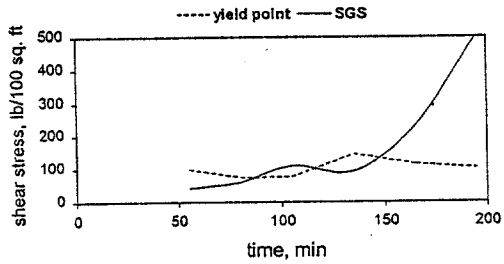
Experimental Measurements of Cement Slurry Compressibility



- cement compressibility affects Top Displacement Amplitude
- cement compressibility responsible for decreasing TDA?
- results:
  - little variation of cement compressibility during cement setting
  - high compressibility at low pressures due to trapped air?

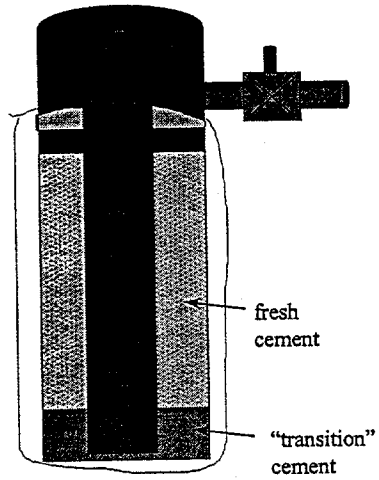
Experimental Measurements of Cement Slurry Rheology

- equipment used:
  - Fann 35 viscometer with F2 spring and custom-coated bob to prevent wall slippage
- results:



Static yield point (SGS) and dynamic yield point vs. time for neat class H cement

TCP Design Model

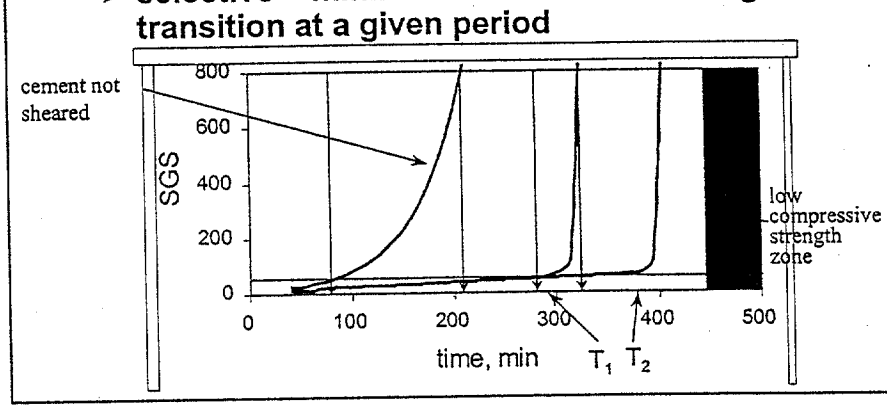


- selective minimization of cement transition time
- bottomhole hydrostatic pressure maintenance

TCP Design Model

Selective Minimization of Cement Transition Time

- cement transition time controlled by pulsations
- transition time minimized
- selective = minimize volume that undergoes transition at a given period

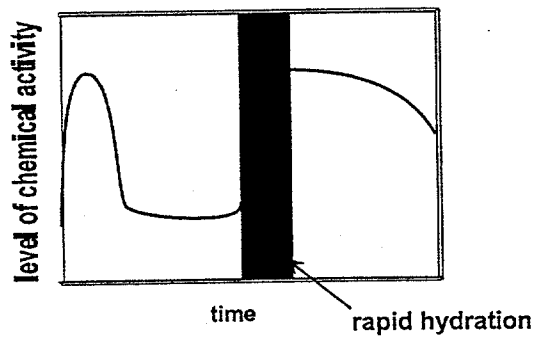


TCP Design Model

Selective Minimization of Cement Transition Time

→ API thickening time (consistometer):

- time to 70 B_c at bottomhole conditions (T_1)
- time to 70 B_c at the top (T_2)



TCP Design Model

Selective Minimization of Cement Transition Time

Procedure:

- TDA such that borehole is not destabilized up to time T_1
- from time T_1 to T_2 rate of top pressure withdrawal to match thickening pattern of cement
- total depth to which pressure pulse can reach should decrease in a rate:

$$\text{rate of pressure withdrawal} = \frac{\text{total depth}}{T_2 - T_1}$$

TCP Design Model

Bottomhole Hydrostatic Pressure Maintenance

- always maintain cement pore pressure greater than formation pore pressure
  - pressure pulses may not be decreased to let fluid invasion

Conclusions

- volume reduction is responsible for pressure loss in setting cement
- cement slurry shearing maintains low yield point of the slurry
- yield point attenuates pressure pulse the most

Conclusions

- TDA declines due to the changing rheological and mechanical properties of setting cement slurry
- TCP design model selectively minimizes cement transition time while maintaining high hydrostatic pressure

DRILL STRING SAFETY VALVE RELIABILITY:

EXPERIMENTAL MEASUREMENTS OF ACTUATING TORQUE

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ABSTRACT

Drill String Safety Valves (DSSV's) are used to prevent blowouts through the drill pipe during underground events in drilling. Several case history reviews of well control events have recently shown evidence of poor reliability with DSSV's. Of the problems reported, valve lock up was most significant, resulting in failure to open or close due to high actuation torque. This paper describes an experimental apparatus and experimental procedures used to quantify the actuating torque of DSSV's under a variety of common operating conditions. Experimentally obtained torque curves are presented for both commercially available and prototype DSSV's, and the results are discussed. Results show the benefit of using special low torque DSSV designs under certain operating conditions.

INTRODUCTION

Drill string safety valves are manually operated ball valves used by the petroleum industry during oil and gas drilling operations. If unexpected subsurface pressures are encountered during drilling, there is a possibility for pressurized flow up the drill string. In a case such as this, the high pressure flow, or blowout, is controlled by manually closing the DSSV. If the pressure is too high, the amount of torque required to close the valve can be very large due to increased frictional forces between internal components in the valve. At some critical pressure the valve fails to close and is said to have suffered *lock-up*, thus increasing the likelihood of a blowout.

A study of blowout preventer (BOP) pressure test results by the Minerals Management Service 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, 1994). Figure 1 details these results.

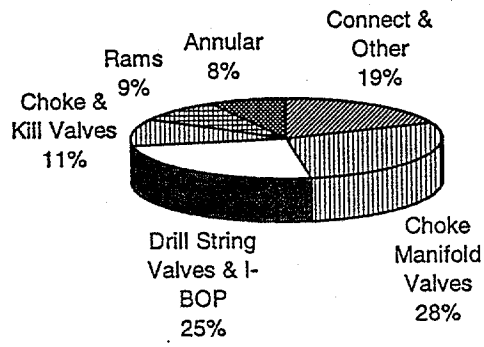

Figure 1: Failure Rates of Well Control Components (Hauser, 1994)

Note that the pressure test failure rate for drill string valves is 25%. This is especially troublesome since there is a low level of redundant protection for blowouts through the inside of the drill string. The other components with high failure rates generally have high redundancy and therefore would not lead to a blowout.

In 1994, an industry survey was conducted (Tarr, 1996a) which identified 29 safety valve failures during well control operations over an unspecified period. The survey was conducted after a number of problems were experienced by industry in 1993 with safety valves leaking in a threatened blowout situation. The survey findings identify common failure modes related to high amounts of torque for DSSV's, including: (1) failure to close due to high torque; (2) failure to open due to high torque; and (3) failure to close due to flow. The focus of this research is to understand the causes of high torque in different valve designs for these different operating conditions. This is viewed as the first step in addressing reliability in DSSV's.

fitted to the socket, and a large wrench is fitted to the torque sensor. The position indicator is a single turn, 500 kilo-ohm potentiometer. It is fitted with a linkage to the hex socket in such a way that turning the socket to open or close the valve causes the potentiometer to turn.

Equalized Pressure Test

The procedure followed for the equalized pressure test continues with the choke and HT 400 pump being connected to the test stand in the configuration shown in Figure 4. With the valve in the closed position, the pump is started and the test fluid (water) is made to flow through the system. The choke is closed until it reaches the desired pressure and the valve experiences the same pressures both above and below the ball. The valve is then opened and the torque versus position data is recorded. This process is repeated for each desired pressure.

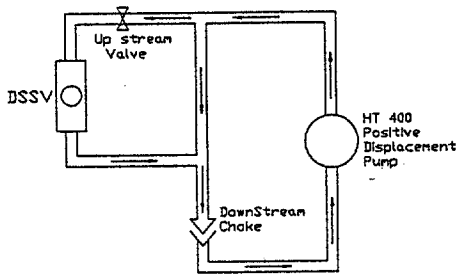

Figure 4: Equalized Pressure Test Set-Up

Differential Pressure Test

The procedure used to test the valves under differential pressure requires that a high pressure diaphragm pump be connected to the test stand as illustrated in Figure 5. With the valve in the open position, the valve and test stand are completely filled with water. The pump is started and the valve and test stand are pressurized to a desired equalized pressure (also referred to as a bias pressure). Once this equalized pressure is reached, the valve is closed. The pump is then started and the bottom of the valve is pressurized to the higher differential pressure. When the proper differential pressure is reached, the valve is then opened and the torque versus position data is recorded. This process is repeated for each desired pressure.

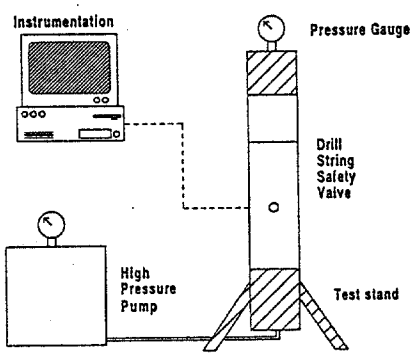

Figure 5: Differential Pressure Test Set-Up

Closing Under Flow Test

The procedure followed for the closing under flow test is also performed with the HT 400 pump and two automatic chokes configured with the test stand as shown in Figure 6 below.

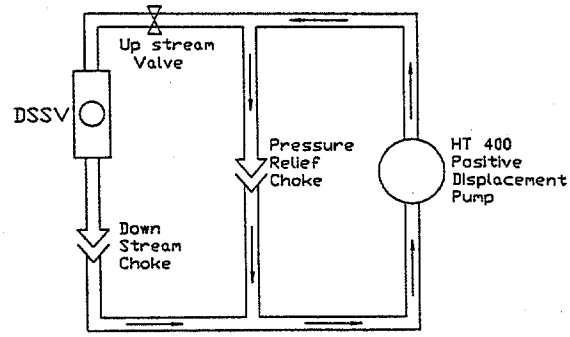

Figure 6: Flow Test Set-Up

With the valve in the open position, the pump is started and the test fluid is made to flow through the system at the desired rate. The pressure relief choke is set to a pressure that is higher than the test pressure. The downstream choke is set to the desired back pressure. This back pressure is essentially an equalized pressure (differential across the valve body) for the valve. When the proper pressure and flow rate have been reached, the valve is closed and the torque versus position data is recorded, processed and saved. This process is repeated for each desired pressure. Tale 1 below summarizes the capabilities of the test stand and the various testing procedures.

Table 1: Summary of Testing Capabilities

Testing Parameter	Capability
Valve Sizes	All sizes via adapters
Test Pressure Ranges for Tests #1 and #3 (psi)	6100 static 3500 flow
Test Pressure Ranges for Test #2 (psi)	10,000 static
Range of Flowrates for Test #3 (GPM)	0-350
Maximum Torque (ft lb)	1000
Sampling Rate of Data Acquisition System (Hz)	10
Pressure Gage Ranges (psi)	Variable up to 10,000

DESCRIPTION OF TEST VALVES

Three valves were tested during the first phase of the testing program, and the results are presented in this paper. Two of the valves are commercially available from manufacturers and the third is a prototype valve developed by the project team earlier in the testing program (Boudreaux, 1996). Of the commercially available valves, one is a standard floating ball design and the other is a special low torque design. These valves will be identified as Valve "A" and Valve "B", respectively. The prototype valve will be designated Valve "C". Each of these valves is described in more detail below.

Figure 2, shown above illustrates the construction of Valve A, which is a typical 2 5/8" ID floating ball design drill string safety valve with a 10,000 psi working pressure rating. As this valve is closed, the ball moves relative to the stem and is forced into the seat (either upper or lower depending upon the direction of flow) to create the seal. This valve represents the industry standard for many years and remains so due to its simple construction and low cost. The apparent disadvantages of this construction are the high amount of friction between the seats and the ball in high differential pressure situations, and the high friction which occurs between the ball and valve body in high equalized pressure situations.

Figure 7 illustrates the construction of Valve B, which is a commercially available 2 3/8" ID, 10,000 psi "low torque" design drill string safety valve. In this design, the ball is free to float in an inner cage that also contains the upper and lower seats. The side slot on the ball allows the ball to move relative to the stem when the valve is in the closed position. Again, as seen in the floating ball design, the pressure forcing the ball into the seats creates the seal. Finally, a set of thrust bearings reside between the ball stem link and the valve body. The apparent advantage of this design is the reduction in friction by use of the thrust bearings and by caging the ball which provides added stability and less binding. This advantage should be apparent during the equalized pressure tests.

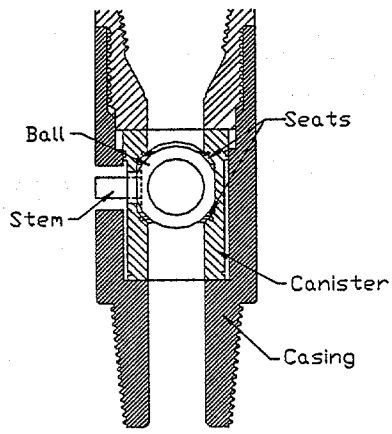

Figure 7: Schematic of Valve B, Special Low Torque Design

Figure 8 illustrates the construction of Valve "C", which is a 2 ¼" ID, 10,000 psi prototype valve design. This valve is similar to Valve B in construction, using a ball located within a cage that also contains the seats. The key difference is that the ball is pseudo-trunnion mounted using two stems, therefore it does not move relative to the stems when the valve is in the closed position. Further, the seats are constrained relative to the ball (i.e.-not floating). Because of this mounting, the pressure of the fluid does not create the seal. Instead, Valve C uses an upper seat loaded with a large spring force to create the sealing force. This allows the seal to be active, regardless of the pressure seen by the ball. With the ball captured on the stems (when in the closed position), large frictional forces can occur between the stems and the valve casing. This is because the stems transfer the differential pressure loads to the valve body via semi-rigid connections. These loads are then accommodated using a radial bearing system. Valve C also takes advantage of the thrust bearing design found in Valve B. Any side forces that are generated during the operation of this valve are accommodated by the thrust bearing. Of course, the primary disadvantage of this design is its complexity and cost relative to the standard valve designs.

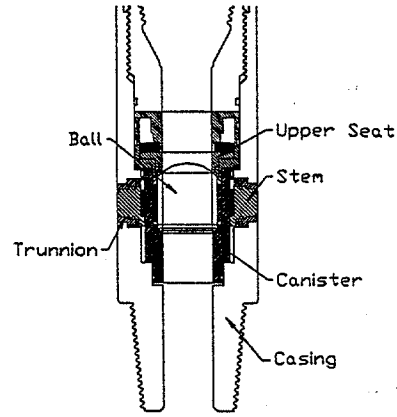

Figure 8: Schematic of Valve C, Low Torque Prototype

RESULTS

Due to the availability of certain testing equipment and of the test valves, different sets of tests were conducted on each of the valves. Specifically, Valves A, B, and C were tested for both equalized pressure and pressurized flow, and only Valve C was tested for differential pressure. In addition, each of the valves were tested in different conditions (new, refurbished, etc.). Valve A was tested in a refurbished condition after the ball, seats, seals and o-rings were replaced. Valve B was used for approximately six months during the process of designing and modifying the experimental test apparatus. As such, the valve's internal components were subject to many opening and closing cycles when it was finally tested after the six month period. Finally, Valve C was tested in the new condition. Table 2 below summarizes the valve sizes and pressure ratings as well as the tests performed on each valve. For the basis of evaluating a valves overall performance, valve lock-up is taken to occur at 400 ft lb of required actuation torque. This is consistent with the proposed API Spec 7 value.

Table 2: Summary of Test Valves and Procedures

Valve	Description	Size Ball ID (in)	Pressure Rating (psi)	Test Procedures
A	Floating Ball	2 5/8	10,000	1,3,4
B	Canister Floating Ball	2 3/8	10,000	1,3,4
C	Prototype Trunnion Mount	2 1/4	10,000	1,2,3,4

Figure 9 gives the results for the equalized pressure tests of Valves A, B and C. These results consist of maximum required actuation torque versus equalized pressure across the ball (differential

pressure across the valve body). The results are as expected for each of the valves. Valve A, the floating ball design, requires the most actuation torque for a given pressure, reaching the lock-up condition at about 2500 psi equalized pressure (2500 differential across the valve body). The two low torque designs, Valve B and Valve C, require less than 200 ft lb of actuation torque up to 5000 psi equalized pressure. Further, Valve C requires slightly more actuation torque than Valve B which is expected due to the preloading springs used to load the ball in Valve C. Figure 9 clearly indicates the advantages of special low torque designs over the standard designs at moderate to high equalized pressures when considering valve lock up.

Figure 10 gives the results for opening the valve under differential pressure for Valve C. Due to the availability of the high pressure pump used in this test, Valves A and B could not be tested under differential pressure. The data is presented for Valve C for the purpose of dissemination, and certain useful results may be implied using this data and the results from the flow tests presented later.

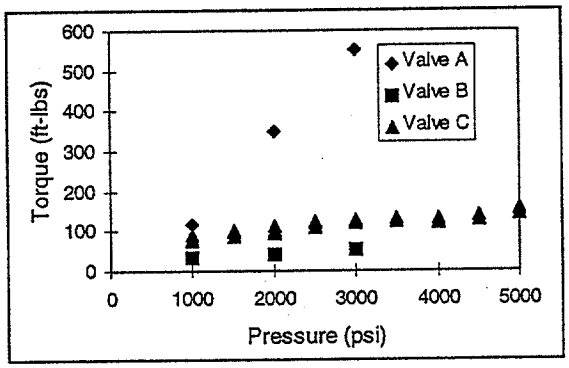

Figure 9: Test Results for Closing Under Equalized Pressure

The differential pressure results in Figure 10 give the maximum required actuation torque versus the differential pressure across the ball, for a variety of equalized pressures. The equalized pressures are essentially bias pressures within the valve (differential across the body, equalized across the ball), and are indicated in Figure 10 by the labels on each data point in the figure. For example, at 2000 psi differential pressure, the required actuation torque varied between 110 ft lb and 380 ft lb for equalized pressures of 1000 psi and 3000 psi, respectively. Figure 10 indicates that valve lock up occurred for Valve C at 4000 psi differential pressure with 1000 equalized pressure.

Figure 11 gives the results for closing the valve under different flowrates for Valves A, B and C. These results consist of maximum actuating torque versus flowrate. The equalized pressure in the valve when it is initially open is 500 psi as set by the choke. When the valve is closed the line pressure increases up to 2000 psi maximum before the safety choke relieves this pressure. In addition, due to the quick closing of the valve under flow, a water hammer pressure may occur. This pressure depends upon the flowrate and is also given in Figure 11. It should be noted that this value is an upper bound as it is based upon instantaneous closing of the valve.

The flowrate results of Figure 11 indicate that for the range of flowrates tested, Valve A (the floating ball valve) required the least actuation torque to close the valve. Further, Figure 11 clearly indicates that once the static friction due to equalized pressure is overcome (stiction), the floating ball valve is less sensitive to differential pressure that occurs as the valve is closed. Static friction exists between the ball and the valve body just before the valve begins to move.

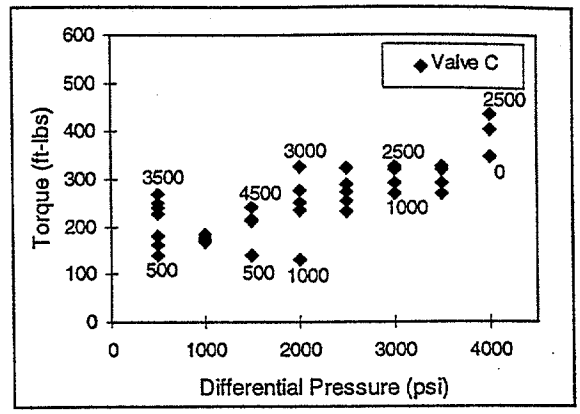

Figure 10: Test Results for Opening Under Differential Pressure

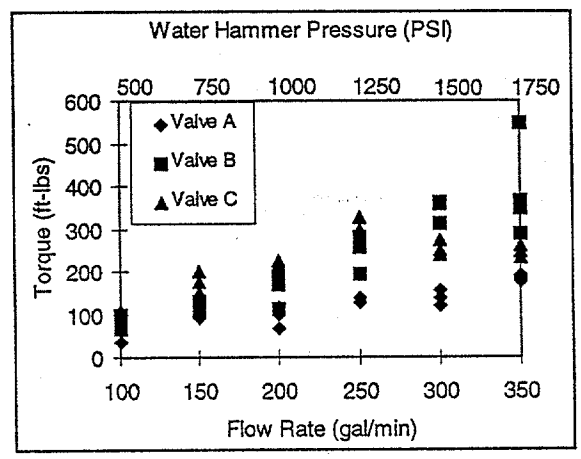

Figure 11: Test Results for Closing Under Flow

The difficulty in interpreting this result is in quantifying the equalized and differential pressures that occur during the flowrate test. Since instantaneous pressure readings are not available from the test data, one must rely on the ranges indicated by the steady state pressure gage readings, and the resulting water hammer pressures. Using these data, the minimum equalized and/or differential pressure that may occur during any flowrate test is 500 psi and the maximum is 2000 psi from the flow choke and the safety choke settings. Furthermore, for each flowrate the water hammer pressures in Figure 11 can be added to the steady state values once the valve is almost fully closed. The second factor which must be considered when interpreting this result is the testing procedure. For every data point of Figure 11, the test valves were initially open and an equalized pressure of 500 psi existed across the valve body. Comparing the results of the equalized pressure tests (Figure 9) to those of the flow test for 500 psi equalized pressure,

it is seen that Valve A requires the least amount of actuation torque. Therefore, the results in Figures 9 and 11 are consistent. These results further suggest that the flowrate tests should be performed for a range of initial equalized pressures beyond the 500 psi capability of the present test set-up. On the basis of Figure 9 it is expected that in such tests it is expected that Valve A would experience lock up before Valves B and C due to the larger equalized pressures.

The flowrate results can be explained by considering the relationship between static and dynamic friction which governs that once the ball begins to turn (close in this case) the coefficient of friction decreases. Therefore the required actuation torque decreases just after the ball begins to move. Whether or not the required actuation torque increases to a level larger than that required to overcome static friction over its closing stroke depends upon the differential pressure seen when the valve is almost fully closed. This effect is better understood by considering the torque versus angular position curve over the valve stroke. Such a curve is illustrated in Figure 12 below for the case of opening under differential pressure. Figure 12 clearly demonstrates the effect of stiction at the point where the ball is beginning to rotate (open in this case). This curve is typical of those taken during testing.

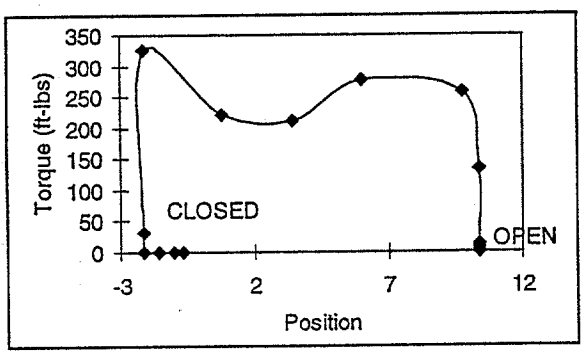

Figure 12: Torque vs. Position of Ball

Finally, Figure 11 also indicates that as the differential pressure increases with each flowrate test, Valve C requires less actuation torque than Valve B. This is to be expected because Valve C is constructed with a special low friction radial bearing which is used to handle loads due to differential pressure, and Valve B was tested after many cycles where Valve C was in the like new condition.

CONCLUSIONS

The results in this paper show that the key to understanding the required actuating torque in drill string safety valves under different operating conditions is proper quantification of both break away torque (stiction) as a function of equalized and/or differential pressure, and dynamic torque over the full valve stroke as a function of equalized and differential pressures. In general, and particularly under flow test conditions, this requires measurement of both torque and internal valve pressures as a function of angular position of the ball during a closing or opening cycle. Therefore, in future work the DSSV test stand will be modified to include pressure sensors above and below the valve. The signals from these sensors can then be read using the data acquisition system. Using the present test stand several conclusions can be drawn from the test data presented in this paper. These are:

1) the floating ball type valve design (Valve A) performs very well (requires low actuation torque) when closing under initially low equalized pressure;

2) the floating ball valve (Valve A) is less sensitive to high differential pressure once it has overcome stiction due to equalized pressure;

3) the low torque designs (Valve B and C) show a significant advantage over the floating ball type design when a moderately high equalized pressure exists (differential across the valve body) and,

4) the prototype Valve C requires less actuation torque than Valve B for the same differential pressure across the ball. This is expected since Valve C is pseudo-trunnion mounted with a low friction radial bearing, but may also be due to the number of cycles on each valve.

Future work will build upon the results presented in this paper. This work will include modifications to measure pressure above and below the valve versus angular position. Further, sensitivity analyses will be conducted to understand the affects of valve age, fluid properties and other properties on DSSV torque performance.

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Drill String Safety Valve Reliability: Experimental Measurements of Actuating Torque

Drill string safety valves (DSSVs) are used to prevent blowouts up the drillpipe when unexpected subsurface pressures are encountered in oil and gas drilling. Several case history reviews of well control events have recently shown evidence of poor reliability with DSSVs. Of the problems reported, valve lock-up was most significant, resulting in failure to open or close due to high actuation torque. This paper describes an experimental apparatus and experimental procedures used to quantify the actuating torque of DSSVs under a variety of common operating conditions. Experimentally obtained torque curves are presented for both commercially available and prototype DSSVs, and the results are discussed. Results show the benefit of using special low-torque DSSV designs under certain operating conditions.

Introduction

Drill string safety valves are manually operated ball valves used by the petroleum industry during oil and gas drilling operations. If unexpected subsurface pressures are encountered during drilling, there is a possibility for pressurized flow up the drill string. In a case such as this, the high-pressure flow, or blowout, is controlled by manually closing the DSSV. If the pressure is too high, the amount of torque required to close the valve can be very large due to increased frictional forces between internal components in the valve. At some critical pressure the valve fails to close and is said to have suffered lock-up, thus increasing the likelihood of a blowout.

A study of blowout preventer (BOP) pressure test results by the Minerals Management Service for the U.S. Outer Continental Shelf during 1993 and 1994 identified drill string safety valves (DSSVs) as one of the least reliable components of the well control system (Hauser, 1994). Figure 1 details these results. Note that the pressure test failure rate for drill string valves is 25 percent. This is especially troublesome since there is a low level of redundant protection for blowouts through the inside of the drill string. The other components with high failure rates generally have high redundancy, and therefore would not lead to a blowout.

In 1994, an industry survey was conducted (Tarr, 1996a) which identified 29 safety valve failures during well control operations over an unspecified period. The survey was conducted after a number of problems were experienced by industry in 1993 with safety valves leaking in a threatened blowout situation. The survey findings identify common failure modes related to high amounts of torque for DSSVs, including: 1) failure to close due to high torque; 2) failure to open due to high torque; and 3) failure to close due to flow. The focus of this research is to understand the causes of high torque in different valve designs for these different operating conditions. This is viewed as the first step in addressing reliability in DSSVs.

This research compliments several efforts that are now underway to address drill string safety valve reliability issues. Specifically, an API task group has been formed to consider revised industry specifications (Tarr, 1996a), and several low-torque prototype valves have been designed and testing programs implemented (Tarr, 1996b; Boudreaux, 1996; Bourgoyne, 1996). This paper describes a testing program for quantifying the torque required to actuate DSSVs under the three aforementioned conditions. The experimental apparatus and procedures are discussed and testing results for three different valves are presented. The results of this testing program will provide a better understanding of valve design issues which affect the torque performance of DSSVs.

Objectives

The primary causes of high actuation torque in DSSVs are due to increased frictional forces between internal components as pressure in the valve builds. Figure 2 illustrates the most common DSSV construction which consists of a floating ball between two seats and a stem which provides manual actuation via a recessed hex fitting. Alternatively, the ball can be trunnion mounted and the seats may float. In either case, the simplest causes of high actuation torque and lock-up occur due to:

- friction between the ball (or ball components) and the valve body when a differential pressure, P, exists between the inside and the outside of the valve casing (body);
- friction between the ball and the seat when a differential pressure, P, exists across the ball resulting in seat loads, F.

The first condition arises when *equalized* pressure exists across the ball (but differential pressure exists across the body). The second condition arises due to the large *differential* pressure across the ball when either sealing from below, or when closing the valve under flow conditions. Closing under flow creates high hydraulic pressures, which in turn increase the torque required for actuation. The objective of the testing program is to evaluate different valve designs under these conditions. To meet this objective, the required actuating torque is measured for each test valve as follows:

1. maximum torque to close/open the test valve for equalized pressure above and below the ball;
2. maximum torque when opening the valve under differential pressure above and below the ball;

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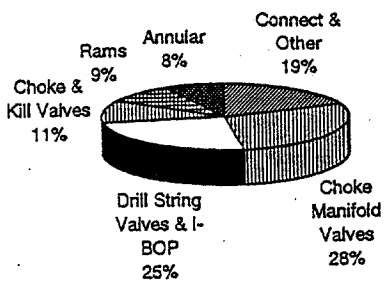

Fig. 1 Failure rates of well control components (Hauser, 1994)

3 maximum torque when closing the valve under flow conditions;
4 torque versus angular position for cases 1–3.

For each test, the valve is evaluated for adequate sealing both across the ball and across the valve body. Also, under all conditions, water is used as the test fluid instead of drilling mud. Tests will be conducted in the future with drilling mud and the results compared to those using water. Proceeding in this fashion allows one to separate those valve design issues related specifically to the difficulties of passing drilling mud through the valve from those that are basic to the design and independent of the fluid used.

Experimental Setup and Procedures

Independent of which test is being performed, the valve is placed into a test stand designed specifically to measure and record the actuating torque versus angular position. The test stand is shown in Fig. 3 and has a bottom and a top section which attach to the test valve. The bottom of the test stand is a box end NC50 5-in. drill pipe connection fitted with a 2-in. 15,000 psi flow line connection. There are three legs welded to the test stand to keep the valves in a vertical position during testing. The top of the test stand is a pin end NC50 5-in. drill pipe connection fitted with a 2-in. 15,000 psi flow line connection. The test valve is screwed into the bottom of the test stand and the top of the test stand is screwed into the test valve. The flow lines are then connected to place the valve in parallel with the pump flow.

The data acquisition system is a Dell computer running National Instruments' "LabView" software using a National Instruments SCXI 1200 analog to digital circuit board. All of the signals sent from the pressure and torque sensors and the position indicator are processed, recorded and stored using this system. The torque sensor is a Teledyne Brown Engineering Model

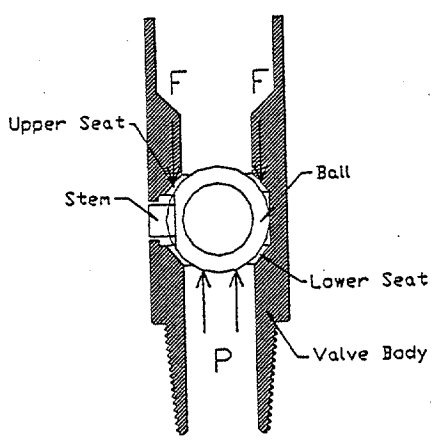

Fig. 2 Basic components of typical DSSV construction

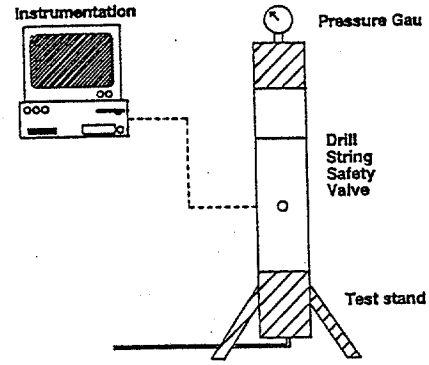

Fig. 3 Test stand common to all tests

17430-100 Socket Wrench Torque Sensor. It has a 1-in. standard female socket wrench fitting on one end and a 1-in. standard male socket wrench fitting on the other. A hex socket is inserted into the test valve stem. The torque sensor is fitted to the socket, and a large wrench is fitted to the torque sensor. The position indicator is a single turn, 500 kilo-ohm potentiometer. It is fitted with a linkage to the hex socket in such a way that turning the socket to open or close the valve causes the potentiometer to turn.

Equalized Pressure Test. The procedure followed for the equalized pressure test continues with the choke and HT 400 pump being connected to the test stand in the configuration shown in Fig. 4. With the valve in the closed position, the pump is started and the test fluid (water) is made to flow through the system. The choke is closed until it reaches the desired pressure and the valve experiences the same pressures both above and below the stem. The valve is then opened and the torque versus position data is recorded. This process is repeated for each desired pressure.

Differential Pressure Test. The procedure used to test the valves under differential pressure requires that a high-pressure diaphragm pump be connected to the test stand as illustrated in Fig. 5. With the valve in the open position, the valve and test stand are completely filled with water. The pump is started and the valve and test stand are pressurized to a desired equalized pressure (also referred to as a bias pressure). Once this equalized pressure is reached, the valve is closed. The pump is then started and the bottom of the valve is pressurized to the higher differential pressure. When the proper differential pressure is reached, the valve is then opened and the torque versus position data is recorded. This process is repeated for each desired pressure.

Closing Under Flow Test. The procedure followed for the closing under flow test is also performed with the HT 400 pump and two automatic chokes configured with the test stand as shown in Fig. 6.

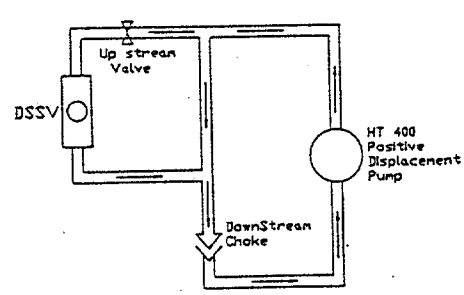

Fig. 4 Equalized pressure test setup

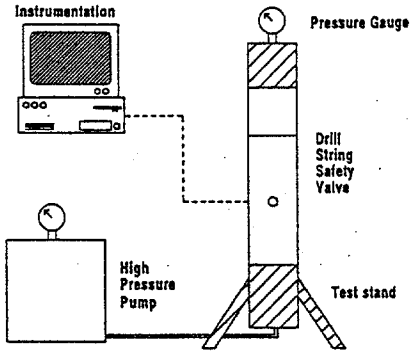

Fig. 5 Differential pressure test setup

With the valve in the open position, the pump is started and the test fluid is made to flow through the system at the desired rate. The pressure relief choke is set to a pressure that is higher than the test pressure. The downstream choke is set to the desired back pressure. This back pressure is essentially an equalized pressure (differential across the valve body) for the valve. When the proper pressure and flow rate have been reached, the valve is closed and the torque versus position data is recorded, processed, and saved. This process is repeated for each desired pressure. Table 1 summarizes the capabilities of the test stand and the various testing procedures.

Description of Test Valves

Three valves were tested during the first phase of the testing program, and the results are presented in this paper. Two of the valves are commercially available from manufacturers and the third is a prototype valve developed by the project team earlier in the testing program (Boudreaux, 1996). Of the commercially available valves, one is a standard floating ball design and the other is a special low-torque design. These valves will be identified as valve A and valve B, respectively. The prototype valve will be designated valve C. Each of these valves will be described in more detail.

Figure 2 illustrates the construction of valve A, which is a typical 2 $\frac{5}{8}$-in. i.d. floating ball design drill string safety valve with a 10,000 psi working pressure rating. As this valve is closed, the ball moves relative to the stem and is forced into the seat (either upper or lower depending upon the direction of flow) to create the seal. This valve represents the industry standard for many years and remains so due to its simple construction and low cost. The apparent disadvantages of this construction are the high amount of friction between the seats and the ball in high differential pressure situations, and the high friction which occurs between the ball and valve body in high equalized pressure situations.

Table 1 Summary of testing capabilities

Testing Parameter	Capability
Valve Sizes	All sizes via adapters
Test Pressure Ranges for Tests #1 and #3 (psi)	6100 static 3500 flow
Test Pressure Ranges for Test #2 (psi)	10,000 static
Range of Flowrates for Test #3 (GPM)	0-350
Maximum Torque (ft lb)	1000
Sampling Rate of Data Acquisition System (Hz)	10
Pressure Gage Ranges (psi)	Variable up to 10,000

Figure 7 illustrates the construction of valve B, which is a commercially available 2 $\frac{3}{8}$-in. i.d., 10,000 psi "low-torque" design drill string safety valve. In this design, the ball is free to float in an inner cage that also contains the upper and lower seats. The side slot on the ball allows the ball to move relative to the stem when the valve is in the closed position. Again, as seen in the floating ball design, the pressure forcing the ball into the seats creates the seal. Finally, a set of thrust bearings reside between the ball stem link and the valve body. The apparent advantage of this design is the reduction in friction by use of the thrust bearings and by caging the ball which provides added stability and less binding. This advantage should be apparent during the equalized pressure tests.

Figure 8 illustrates the construction of valve C, which is a 2 $\frac{1}{4}$-in. i.d., 10,000 psi prototype valve design. This valve is similar to valve B in construction, using a ball located within a cage that also contains the seats. The key difference is that the ball is "pseudo-trunnion mounted" (trunnion mounted with a small tolerance to allow movement at certain positions) using two stems; therefore, it does not move relative to the stems when the valve is in the closed position. Further, the seats are constrained relative to the ball (i.e., not floating). Because of this mounting, the pressure of the fluid does not create the seal. Instead, valve C uses an upper seat loaded with a large spring force to create the sealing force. This allows the seal to be active, regardless of the pressure seen by the ball. With the ball captured on the stems (when in the closed position), large frictional forces can occur between the stems and the valve

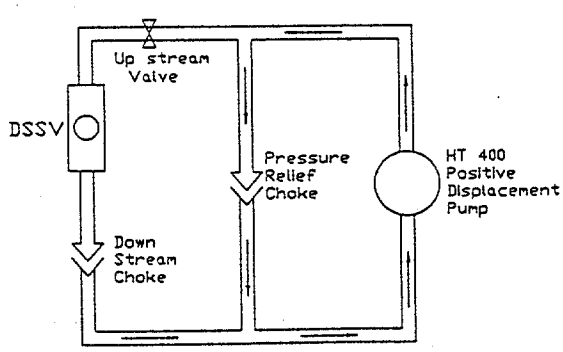

Fig. 6 Flow test setup

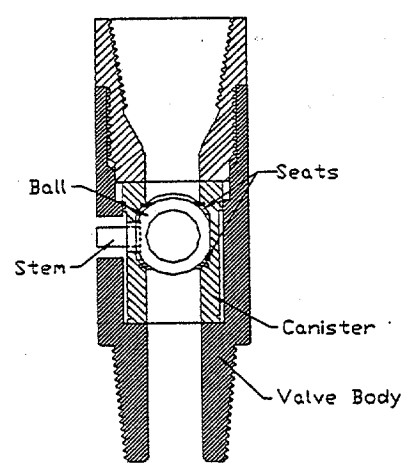

Fig. 7 Schematic of valve B, special low-torque design

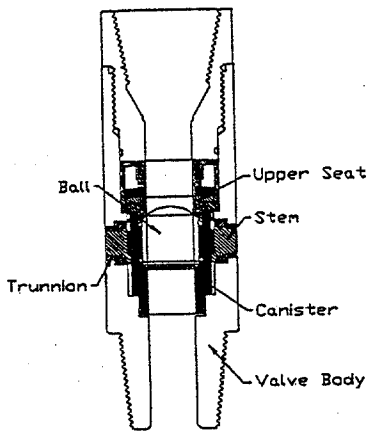

Fig. 8 Schematic of valve C, low-torque prototype

casing. This is because the stems transfer the differential pressure loads to the valve body via semi-rigid connections. These loads are then accommodated using a radial bearing system. Valve C also takes advantage of the thrust bearing design found in valve B. Any side forces that are generated during the operation of this valve are accommodated by the thrust bearing. Of course, the primary disadvantage of this design is its complexity and cost relative to the standard valve designs.

Results

Due to the availability of certain testing equipment and of the test valves, different sets of tests were conducted on each of the valves. Specifically, valves A, B, and C were tested for both equalized pressure and pressurized flow, and only valve C was tested for differential pressure. In addition, each of the valves were tested in different conditions (new, refurbished, etc.). Valve A was tested in a refurbished condition after the ball, seats, seals, and O-rings were replaced. Valve B was used for approximately 6 mo during the process of designing and modifying the experimental test apparatus. As such, the valve's internal components were subject to many opening and closing cycles when it was finally tested after the six month period. Finally, valve C was tested in the new condition. Table 2 summarizes the valve sizes and pressure ratings as well as the tests performed on each valve. For the basis of evaluating a valve's overall performance, valve lock-up is taken to occur at 400 ft-lb of required actuation torque. This is consistent with the proposed API Spec 7 value.

Figure 9 gives the results for the equalized pressure tests of valves A, B, and C. These results consist of maximum required actuation torque versus equalized pressure across the ball (differential actuation torque) versus equalized pressure across the ball (differential pressure across the valve body). The results

Table 2 Summary of test valves and procedures

Valve	Description	Size Ball ID (in)	Pressure Rating (psi)	Test Procedures
A	Floating Ball	2 5/8	10,000	1,3,4
B	Canister Floating Ball	2 3/8	10,000	1,3,4
C	Prototype Trunnion Mount	2 1/4	10,000	1,2,3,4

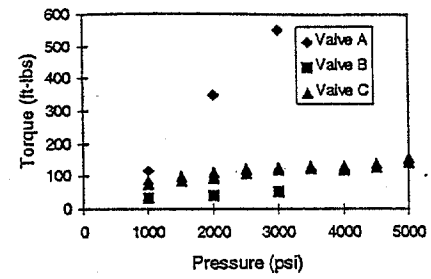

Fig. 9 Test results for closing under equalized pressure

are as expected for each of the valves. Valve A, the floating ball design, requires the most actuation torque for a given pressure, reaching the lock-up condition at about 2500 psi equalized pressure (2500 differential across the valve body). The two low-torque designs, valves B and C, require less than 200 ft-lb of actuation torque up to 5000 psi equalized pressure. Further, valve C requires slightly more actuation torque than valve B, which is expected due to the preloading springs used to load the ball in valve C. Figure 9 clearly indicates the advantages of special low-torque designs over the standard designs at moderate to high equalized pressures when considering valve lock-up.

Figure 10 gives the results for opening the valve under differential pressure for valve C. Due to the availability of the high pressure pump used in this test, valves A and B could not be tested under differential pressure. The data is presented for valve C for the purpose of dissemination, and certain useful results may be implied using this data and the results from the flow tests presented later.

The differential pressure results in Fig. 10 give the maximum required actuation torque versus the differential pressure across the ball, for a variety of equalized pressures. The equalized pressures are essentially bias pressures within the valve (differential across the body, equalized across the ball), and are indicated in Fig. 10 by the labels on each data point in the figure. For example, at 2000 psi differential pressure, the required actuation torque varied between 110 ft-lb and 380 ft-lb for equalized pressures of 1000 and 3000 psi, respectively. Figure 10 indicates that valve lock-up occurred for valve C at 4000 psi differential pressure with 1000 equalized pressure.

Figure 11 gives the results for closing the valve under different flow rates for valves A, B, and C. These results consist of maximum actuating torque versus flow rate. The equalized pressure in the valve when it is initially open is 500 psi as set by the choke. When the valve is closed, the line pressure increases up to 2000 psi maximum before the safety choke relieves this pressure. In addition, due to the quick closing of the

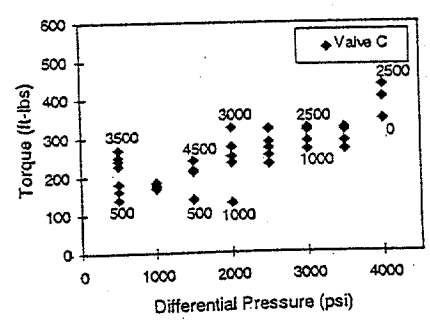

Fig. 10 Test results for opening under differential pressure

valve under flow, a water hammer pressure may occur. This pressure depends upon the flow rate and is also given in Fig. 11. It should be noted that this value is an upper bound as it is based upon instantaneous closing of the valve.

The flow rate results of Fig. 11 indicate that for the range of flow rates tested, valve A (the floating ball valve) required the least actuation torque to close the valve. Further, Fig. 11 clearly indicates that once the static friction due to equalized pressure is overcome (stiction), the floating ball valve is less sensitive to differential pressure that occurs as the valve is closed. Static friction exists between the ball and the valve body just before the valve begins to move.

The difficulty in interpreting this result is in quantifying the equalized and differential pressures that occur during the flow rate test. Since instantaneous pressure readings are not available from the test data, one must rely on the ranges indicated by the steady-state pressure gage readings, and the resulting water hammer pressures. Using these data, the minimum equalized and/or differential pressure that may occur during any flow rate test is 500 psi and the maximum is 2000 psi from the flow choke and the safety choke settings. Furthermore, for each flow rate, the water hammer pressures in Fig. 11 can be added to the steady-state values once the valve is almost fully closed. The second factor which must be considered when interpreting this result is the testing procedure. For every data point of Fig. 11, the test valves were initially open and an equalized pressure of 500 psi existed across the valve body. Comparing the results of the equalized pressure tests (Fig. 9) to those of the flow test for 500 psi equalized pressure, it is seen that valve A requires the least amount of actuation torque. Therefore, the results in Figs. 9 and 11 are consistent. These results further suggest that the flow rate tests should be performed for a range of initial equalized pressures beyond the 500-psi capability of the present test setup. On the basis of Fig. 9, it is expected that in such tests, valve A would experience lock-up before valves B and C due to the larger equalized pressures.

The flow rate results can be explained by considering the relationship between static and dynamic friction which governs that once the ball begins to turn (close in this case), the coefficient of friction decreases. Therefore the required actuation torque decreases just after the ball begins to move. Whether or not the required actuation torque increases to a level larger than that required to overcome static friction over its closing stroke depends upon the differential pressure seen when the valve is almost fully closed. This effect is better understood by considering the torque versus angular position curve over the valve stroke. Such a curve is illustrated in Fig. 12 for the case of opening under differential pressure. Figure 12 clearly demonstrates the effect of stiction at the point where the ball is beginning to rotate (open in this case). This curve is typical of those taken during testing.

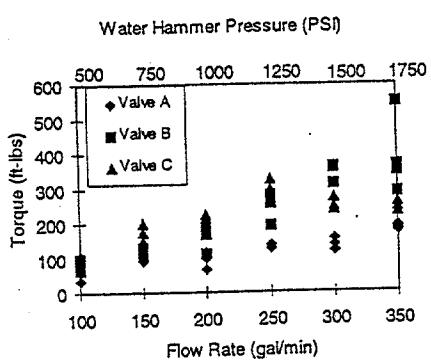

Fig. 11 Test results for closing under flow

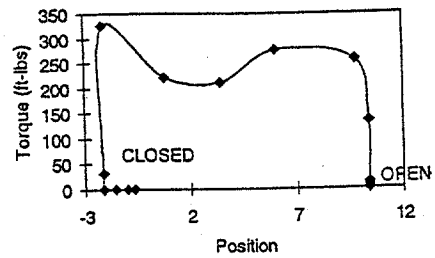

Fig. 12 Torque versus position of ball

Finally, Fig. 11 also indicates that as the differential pressure increases with each flow rate test, valve C requires less actuation torque than valve B. This is to be expected because valve C is constructed with a special low-friction radial bearing which is used to handle loads due to differential pressure, and valve B was tested after many cycles where valve C was in the "like new" condition.

Conclusions

The results in this paper show that the key to understanding the required actuating torque in drill string safety valves under different operating conditions is proper quantification of both break away torque (stiction) as a function of equalized and/or differential pressure, and dynamic torque over the full valve stroke as a function of equalized and differential pressures. In general, and particularly under flow test conditions, this requires measurement of both torque and internal valve pressures as a function of angular position of the ball during a closing or opening cycle. Therefore, in future work the DSSV test stand will be modified to include pressure sensors above and below the valve. Using the present test stand, several conclusions can be drawn from the test data presented in this paper. These are:

1. The floating ball-type valve design (valve A) performs very well (requires low actuation torque) when closing under initially low equalized pressure.
2. The floating ball valve (valve A) is less sensitive to high differential pressure once it has overcome stiction due to equalized pressures.
3. The low-torque designs (valves B and C) show a significant advantage over the floating ball-type design when a moderately high equalized pressure exists (differential across the valve body).
4. The prototype valve C requires less actuation torque than valve B for the same differential pressure across the ball. This is expected since valve C is pseudo-trunnion mounted with a low-friction radial bearing, but may also be due to the number of cycles on each valve.
5. The large closing torques measured for all three valves can prevent the valves from being closed to serve their intended function of stopping blowouts up the drill string.

Future work will build upon the results presented in this paper. Of interest are sensitivity analyses to quantify the affects of valve age, fluid properties, and other properties on DSSV torque performance.

Acknowledgments

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oratory (PERTTL) under support from the United States Department of Interior Minerals Management Service.

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DSSV Reliability Project

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  - L.S. Stephens
  - A.T. Bourgoyne, Jr.
- Present and Past Students (ME & PetE)
  - E.D. Coleman
  - M.A. Casemore
  - J. Micas
  - B. Puls
  - D. Reed
  - L. Fish
  - K. Eubanks
  - T.T. Core, Jr.
  - B.W. Smith
  - J. Francis
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  - J. Boudreaux
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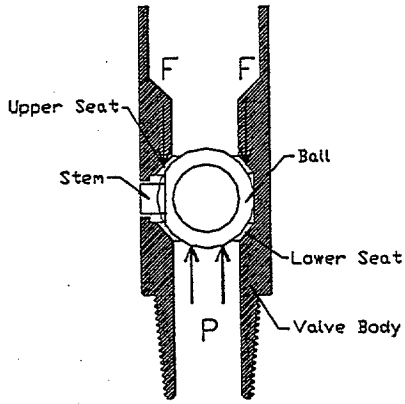
  - B. Bourgeois
- Sponsor: US Dept. of Interior, MMS

Outline

- Problem Statement
- Objectives
- Program Overview
- Valve Testing Program
  - Description of Test Valves
  - Results
  - Conclusions
- Future & Continuing Work
  - Test Stand Upgrade
  - Valve Storage Container

Problem Statement

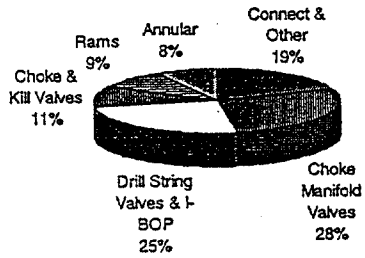
- Manually Operated Ball Valve
- Primary Flow Control Device for Pressure Kicks up the Drill String
- *High* Pressure Kicks lead to Valve Lock-up and Loss of Well Control



Typical DSSV

Problem Statement

- Low Reliability
- No Redundancy
- Mobile Survey (Tarr, 1996):
  - Failure To Close/Open Due to High Torque
  - Failure to Close Under Flow
  - Others



Failure Rates of Well Control Components (Hauser, 1994)

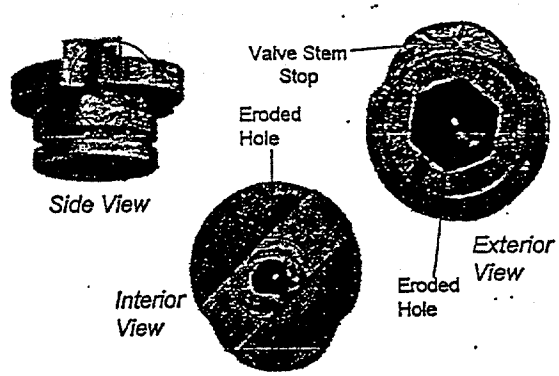


Figure 5 - Valve Stem Failure

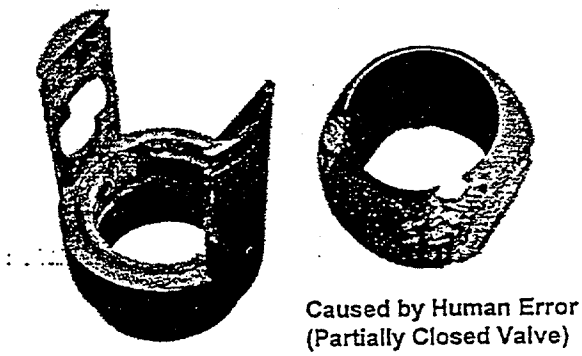


Figure 6 - Erosion of Ball and Seat

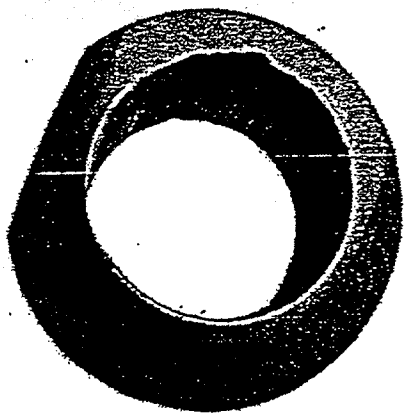


Figure 7 - Wireline-Cut Ball

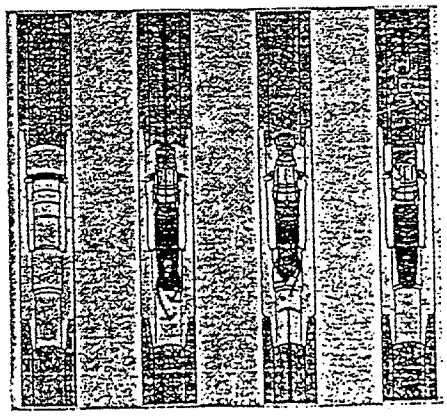


Figure 8 - Drop-In Check Valve

Objectives

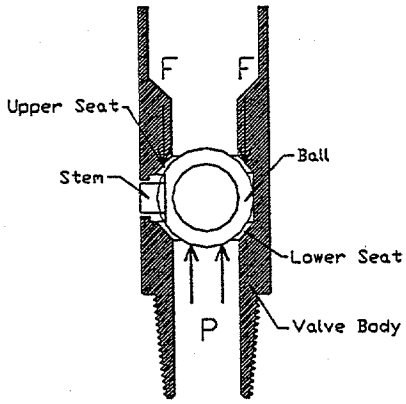
- to quantify *how* DSSV design and/or operating procedures impact the overall valve reliability
  - DSSV Testing Program
    - Actuation Torque vs. Position
    - Equalized Pressure, Differential Pressure, Flow
  - New DSSV Design Program
    - Radial and Thrust Bearings
    - Spring Loaded Seats
  - Storage Vessel Design and Testing
    - DSSV in "Like-New" Condition

Valve Testing Program

- Focuses on causes of high closing/opening torque
  - Three designs tested
    - Valve A - Standard Floating Ball Valve
    - Valve B - Low Torque Design
    - Valve C - LSU Prototype Low Torque Design
  - Three tests available
    - Equalized Pressure
    - Differential Pressure
    - Closing Under Flow
  - All tests done with water

Experimental Procedures

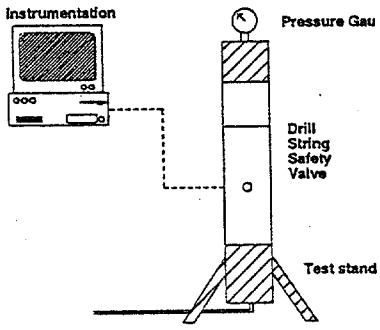
- Conditions Under which Lock-up (400 ft*lb) Reported to Occur
  - High Equalized Pressure
  - High Differential Pressure
  - Closing under high flowrates



Shows Differential Pressure Condition

Experimental Procedures

- Experimental Apparatus Designed to Measure:
  - Maximum Torque required to Close/Open under **Equalized Pressure**
  - Maximum Torque required to Open under **Differential Pressure**
  - Maximum Torque required to close under different **flowrates**
  - Torque vs. Angular Position for each of the above tests



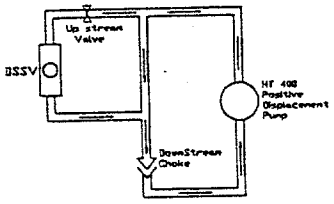
Experimental Procedures

Summary of Testing Capabilities

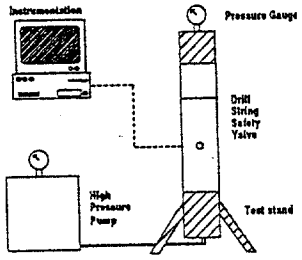
Testing Parameter	Capability
Valve Sizes	All sizes via adapters
Test Pressure Ranges for Tests #1 and #3 (psi)	6100 static 3500 flow
Test Pressure Ranges for Test #2 (psi)	10,000 static
Range of Flowrates for Test #3 (GPM)	0-350
Maximum Torque (ft lb)	1000
Sampling Rate of Data Acquisition System (Hz)	10
Pressure Gage Ranges (psi)	Variable up to 10,000

Experimental Procedures

Equalized Pressure Test

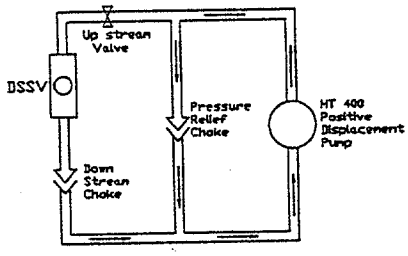


Differential Pressure Test



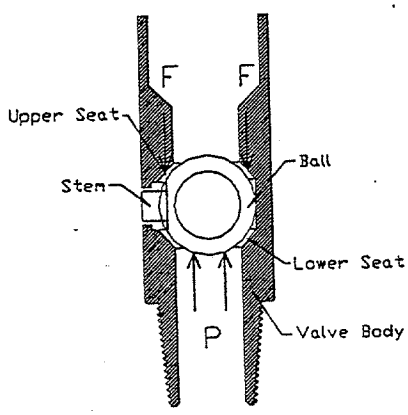
Experimental Procedures

Closing Under Flow Test



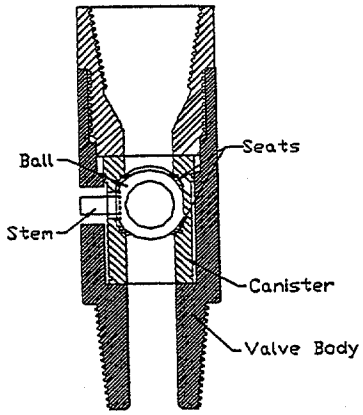
Description of Valves Tested

- Valve "A"
  - Commercially Available
  - Standard Floating Ball Desig
  - 2-5/8" ID
  - 10,000 psi pressure rating



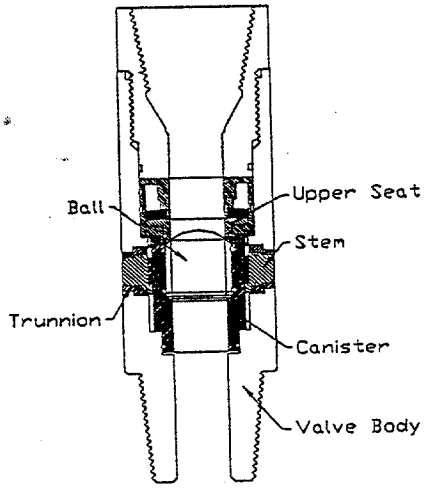
Description of Valves Tested

- Valve "B"
  - Commercially Available
  - Low Torque -- Canister Design
  - 2-3/8" ID
  - 10,000 psi pressure rating



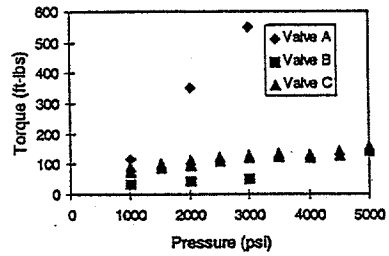
Description of Valves Tested

- Valve "C"
  - LSU Prototype
  - Pseudo-Trunnion Mounted
  - Canister Design
  - 2-1/4" ID
  - 10,000 psi pressure rating



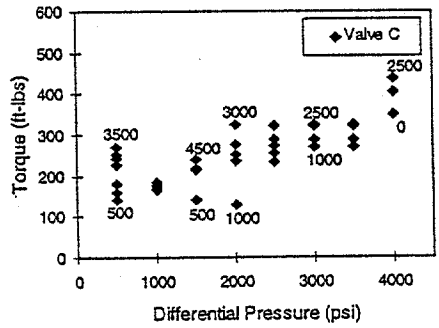
Results

- Equalized Pressure Tests
  - Valve A – Floating Ball
  - Valve B – Low Torque Design with Small Preload Torque
  - Valve C – Low Torque Design with Large Preload Torque



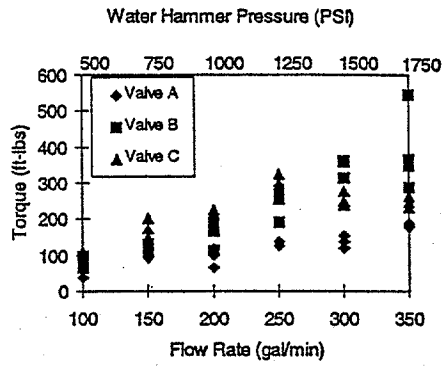
Results

- Differential Pressure Tests
  - Not Available for Valve "A" or "C"
  - Torque shown for various equalized pressures at each differential pressure
  - Lock-up occurs for valve C at 4000 psi differential and 1000 psi equalized pressure



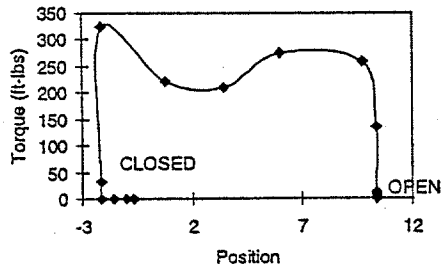
Results

- Closing Under Flow Test
  - Valve "A", floating ball valve gives best results
  - Not surprising
    - Consistent with initially low equalized pressure results
  - This test embodies both the equalized pressure and the differential pressure tests



Results

- Torque Vs. Angular Position for closing under flow
  - Stiction due to equalized pressure at open position
  - Torque decreases after stiction is overcome
  - As differential pressure builds, closing torque increases
- Better Results can be obtained by:
  - increasing sampling rate
  - measuring pressure above and below the stem vs. position



Conclusions

- The floating ball type valve design (Valve A) requires very low actuation torque when closing under initially low equalized pressure.

- The low torque designs (Valves B and C) show a significant advantage over the floating ball design (Valve A) in overcoming stiction (high equalized pressure).

Conclusions (cont'd)

- The prototype valve ("C") requires less actuation torque than Valve B for the same differential pressure.
  - Design ? or Number of Cycles ?

- The large closing torques measured for all three valves can prevent the valves from being closed to serve their intended function of stopping blowouts up the drillstring.

On-going and Future Work

- Improve testing procedures (Dec 97-Mar 98)
  - Install pressure taps above and below valve in stand
  - Increase sampling rate on DAQ (better torque/pressure vs. angle)
- Test Valves in a variety of Operating Conditions (Spr-Summ 98)
  - Sensitivity to age, condition, etc.
  - Sensitivity to DSSV design parameters
  - Quantify the effect of using a "storage vessel"
- Make recommendations for DSSV design and handling on rig floor to improve reliability in blowout situations

BOREHOLE FAILURE RESULTING FROM FORMATION INTEGRITY (LEAK-OFF) TESTING IN UPPER MARINE SEDIMENTS OFFSHORE

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ABSTRACT

This paper presents the results of a theoretical study, supported with the final element analysis into potential loss of external integrity around a casing shoe resulting from leak-off testing (LOT) in upper marine sediments (UMS). Three types of possible failures from LOTs were considered: vertical fracture, horizontal fracture, and a channel outside cemented annulus. It is proved in the paper that vertical fracture is the most unlikely failure of the three. The other two types of failure can be distinguished by different values of propagation pressures. Although horizontal fractures are initiated at low pressure in the plastic zone around the wellbore, they cannot propagate beyond the plastic zone until wellbore pressures exceed overburden pressures. Annular channels, on the other hand, may propagate upwards at pressures lower than overburden pressure. The paper shows that these channels are initiated at pressures equal to the contact stress between cement and rock and their propagation pressures are on average 3.5 - fold greater than contact stress. It is also explained how to identify the UMS with high risk of annular channeling during LOTs.

NOMENCLATURE

D = depth of sediment, ft;
D_T = total vertical depth, ft;
E = Young's modulus, psi;
E_{cc} = Young's modulus of casing and cement, psi;
N = rock property constant, $(1+\sin\varphi)/(1-\sin\varphi)$;
p_f = fracture pressure, psi;
p_{max} = maximum pressure of LOT curve, psi;
p_w = effective wellbore pressure before LOT (the difference of wellbore pressure and formation pressure), psi;
p'_w, p''_w = critical effective pressures, psi;
d_{cc} = casing internal diameter, in.;
r = radial distance from the wellbore center line, in;
r_w = radius of the wall of a wellbore, in;
γ = submerged unit weight of sediment, lb/gal;
Δp_w = increase of wellbore pressure, psi;
σ_0 = unconfined axial compressive strength, psi;
σ_1, σ_3 = the largest and smallest principle stresses, psi;
σ_{over} = overburden pressure, psi;
σ_c = contact stress between well cement and rock, psi;
σ_h, σ_{z0} = far-field effective horizontal and vertical stress, psi;
$\sigma_r, \sigma_\theta, \sigma_z$ = radial, tangential, and vertical effective stresses around a wellbore, psi;
$\Delta\sigma_r, \Delta\sigma_\theta, \Delta\sigma_z$ = increment of radial, tangential, and vertical effective stresses, respectively, psi;
$\sigma_{rw}, \sigma_{\theta w}, \sigma_{zw}$ = radial, tangential and vertical stresses at the wall of a wellbore, psi;
τ_0, φ = cohesive strength and internal friction angle, psi, deg.;
μ = Poisson's Ratio.

INTRODUCTION

Leak-off testing (LOT) in shallow (upper) marine sediments (UMS) is performed for the same reason as deeper formations; to estimate how much pressure can be applied to the rock just below the casing shoe before the shoe/rock system fails. Also, the LOT procedures for both situations are conceptually the same; to stress out

the shoe/rock system until the first sign of failure appears. The problem is that in deep rocks the beginning of failure, i.e. initiation of vertical fracture is well supported by elastic theory and relatively easy to recognize. This is not the case, however, for UMS - soft and weak deposits within 1000 - 3000 feet below the sea bottom.

Typically, LOTs recorded in UMS give nonlinear plots of pressure versus volume injected with no clear indication of the beginning of failure. Since the elastic theory cannot explain the non-linearity of these plots, other phenomena such as mud filtration, micro-fracturing or "plastic deformation" have been used to explain hypothetically this non-linearity. Besides, operators have long feared that without clear indication of the offset of rock failure a permanent damage to the annular seal may be underway during the test. To avoid the damage, many operators do not perform LOTs in UMS while others put limits (with safety margin) on the maximum pressure during the test. During these tests, formation is pressurized only slightly above that used in the well design testing to failure. Also, other operators perform LOTs as a series of slow pumping periods intermittent with the stop-pump/hold-pressure periods. Typically, these tests are terminated when the instantaneous shut-in pressure (ISIP) stops increasing after subsequent periods of pumping. The measurement of ISIP values is more commonly done in conjunction with hydraulic fracturing operations than with drilling operations.

Numerous LOT field results in UMS have shown high values of fracture pressure gradients ranging from 0.75 psi/ft to over 1.0 psi/ft. Typical values are shown in Table 1 (Wojtanowicz and Zhou, 1996); thus, UMS appeared to be much stronger than it had been previously believed. It was even reported that for some shallow sediments, fracturing gradients can become two-fold greater than those for deeper sediments (Arifun and Sumpennpo, 1994).

One way of predicting the high strength of shallow sediments is to use equations from the theory of fracturing deep sediments, and make an 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 has no physical meaning because it uses formulas for vertical fractures and assumes that the sediments follow a "pseudo" elastic behavior.

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, incidents of shallow gas or water flow behind casing would result from a lack of external borehole integrity. Once the integrity is lost, small migration behind cement would eventually develop into a continuous and massive upward flow of these fluids through the sediment outside the wellbore. This phenomenon, known as cratering, has been recently explained using several conceptual mechanisms such as wellbore erosion liquefaction, piping or caving (Rocha and Bourgoyne, 1993). In this study, we assumed that all these mechanisms would originate from a channel or fracture outside the well which provided a flow conduit for pressurized fluids from deeper strata. It is believed that this conduit results from imperfect cementing. There is a possibility, however, that faulty LOT might initialize such a conduit.

Objectives and Method of This Work

The objective of this work is to examine the potential loss of external integrity of surface holes in UMS resulting from LOT. Our presumption is that, prior to LOT in UMS, the formation around the casing shoe is in a plastic state, which would determine stresses and deformations induced by LOT. Also, we consider three hypothetical mechanisms of mechanical failure at the casing shoe: vertical fracture, horizontal fracture and annular channel. The channel may develop outside the well's cement in the result of radial plastic deformation around the shoe. If the deformation is large enough, the channel will open to mud invasion and propagate upwards.

The methodology used in this research involved a theoretical analysis based upon analytical modeling of the three-dimensional stresses distribution at the mid-point of the open hole below the shoe before and during LOT. In addition, a numerical analysis was performed using the finite element software package ABAQUS. The numerical approach was needed to determine distribution of stresses and strains at and below the casing shoe in the open hole section of the well. Complexity of stress concentration in this area precluded the use of analytical analysis methods.

ANALYTICAL ANALYSIS OF LOT - INDUCED VERTICAL FRACTURE IN UMS

Two major factors control the distribution of stresses around the casing shoe in UMS: the effect of vertical stress and the presence of a plastic zone around the well. In this section we will quantify these effects. In our analysis, we will consider only effective stresses (i.e., wellbore pressure is the difference between the actual wellbore pressure and formation pore pressure, or drilling mud is a non-penetrating fluid). Also, we make two additional assumptions: (1) UMS is isotropic and homogeneous; and, (2) the sign convention considers compressive and tensile stress as positive and negative respectively.

State of Stress Prior to LOT

Conventional analytical models used for LOT analysis and prediction of fracture gradients are based upon a two-dimensional elastic distribution of stresses around a hollow cylinder on the plane strain (Harrison et al., 1954, Hubbert and Willis, 1957, Mathews and Kelly, 1967, Christman, 1973, Constant and Bourgoyne, 1988, Warpinski and Smith, 1989, Bourgoyne et al., 1991, Eaton and Eaton, 1997). The stress distribution is:

$$\begin{aligned} \sigma_r &= \sigma_h - (\sigma_h - p_w)\frac{r_w^2}{r^2} \\ \sigma_\theta &= \sigma_h + (\sigma_h - p_w)\frac{r_w^2}{r^2} \\ \sigma_z &= \sigma_{z0} \end{aligned} \tag{1}$$

Unlike for deep wells with boreholes in elastic state, drilling in UMS engenders two concentric zones of stress distribution: plastic - next to the well, and elastic - outside the plastic zone. In the plastic zone, the smallest value of vertical stress is at the wellbore wall and increases away from the well to its constant value in-situ. This pattern has been determined for various types of plastic sediments (Gnirk, 1972, Risnes et al., 1982, Wang and Dusseault, 1991). Obert and Duvall (1967) modeled the distribution of stresses in these two zones and proved that size of the plastic zone depends on the compressive strength of the sediment. Similarly to these authors (who used the Tresca criterion sediment with no friction), we derive stress distribution formulas by applying the Mohr - Coulomb yield criterion:

$$\sigma_1 - N\sigma_3 = \sigma_0$$
$$\sigma_0 = 2\tau_0 \cos\varphi / (1-\sin\varphi)$$
$$N = (1+\sin\varphi)/(1-\sin\varphi) \qquad (2)$$

and combining Eqs. (1) and (2) with the stress equilibrium formula, which gives the following expressions for tangential (largest), σ_θ, and radial (smallest), σ_r, compressive stresses in the plastic zone as

$$\sigma_r = (p_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1}$$
$$\sigma_\theta = N(p_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1} \qquad (3a)$$

Equation (3a) implies that an intermediate stress in the plastic zone is vertical stress. Many authors made this simplification (Gnirk, 1972, Wang and Dusseault, 1991). Although vertical stress is likely to become the largest of the three stresses away from the well, its value at the wellbore is close to the tangential stress value. This simplification is supported by the results of Risnes et al. (1982). These authors assumed no vertical displacement and showed that vertical stress is equal to tangential stress in an inner plastic zone next to the wellbore. (The inner plastic zone is determined by the radius corresponding to the maximum value of tangential stress away from the wellbore.) Also, our recent results of finite element analysis showed very close values of these two stresses near the well (Wojtanowicz and Zhou, 1996). Therefore, we conclude that vertical stress in the inner plastic zone can be approximated by the expression,

$$\sigma_z = N(p_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1} \qquad (3b)$$

Conditions for Plastic Failure Around Wellbores

Let us consider a wellbore initially in elastic state with well pressure being reduced. When pressure in the wellbore drops below a critical value, i.e. $p_w < p'_w$, and the wellbore wall yields and a plastic zone is created around the wellbore. A formula for critical pressure can be derived by substituting the larger of the two stresses at the wellbore wall, $\sigma_{\theta w}$ or σ_{zw}, from Eq. (1) into the Mohr-Coulomb yield criterion - Eq. (2), which gives

$$p'_w = \frac{2\sigma_h - \sigma_0}{1+N} \qquad (4a)$$

for: $\sigma_{\theta w} > \sigma_{zw}$ or, $p_w < \frac{3\mu - 1}{\mu}\sigma_h$

and,

$$p'_w = (\sigma_{z0} - \sigma_0)/N \qquad (4b)$$

for: $\sigma_{\theta w} < \sigma_{zw}$ or, $p_w > \frac{3\mu - 1}{\mu}\sigma_h$

The above conditions for using either formula (4a), or (4b) can be derived from Eq. (1), by considering tangential stress at the wall:

$$\sigma_{\theta w} = 2\sigma_h - p_w$$

and the stress ratio relation:

$$\sigma_h / \sigma_{z0} = \mu / (1-\mu).$$

LOT - Induced Vertical Fracture in UMS

During LOT, an additional pressure, Δp_W, is added to the wellbore pressure. This pressure change reduces elastic deformation corresponding to the change of elastic stresses determined from Eq. (1) as

$$\Delta\sigma_r = \Delta p_w \frac{r_w^2}{r^2}$$
$$\Delta\sigma_\theta = -\Delta p_w \frac{r_w^2}{r^2} \qquad (5a)$$
$$\Delta\sigma_z = 0$$

The resulting stress is calculated by adding this incremental elastic stress due to LOT to the initial plastic stress - before LOT, in Eq. (3), as

$$\sigma_r = (p_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1} + \Delta p_w \frac{r_w^2}{r^2}$$
$$\sigma_\theta = N(p_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1} - \Delta p_w \frac{r_w^2}{r^2} \qquad (5b)$$
$$\sigma_z = N(p_w + \frac{\sigma_0}{N-1})(\frac{r}{r_w})^{N-1} - \frac{\sigma_0}{N-1}$$

Equation (5b) implies that LOT reduces tangential compressive stress, increases radial compressive stress, and leaves vertical compressive stress unaffected by Δp_W. The insensitivity of vertical stress to Δp_W results from our assumption that borehole fluid does not penetrate the rock so it cannot work in vertical direction.

At a certain value of LOT pressure, tangential stress becomes equal to radial stress and total elastic deformation at the wall is eliminated. As Δp_W continues to increase, the wall deforms elastically in a radial direction until its differential stress reaches the plastic limit or tangential stress converts to tension, whichever comes first. Our calculations indicate that for UMS the plastic limit comes first (i.e. two principal stresses meet again the Mohr-Coulomb criterion) and the second plastic failure (re-yielding) occurs before the wall goes to tension. The re-yielding occurs when tangential stress is reduced to initial wellbore pressure, $\sigma_\theta = p_w$, and the wellbore pressure is:

$$p_w + \Delta p_w = N p_w + \sigma_0 \tag{6}$$

The expression (6) can be derived by substituting $\sigma_r = \sigma_1$ and $\sigma_\theta = \sigma_3$ at the borehole wall from Eq. (5b) into Eq. (2) that gives: $\Delta p_w = (N-1)p_w + \sigma_0$.

After re-yielding, tangential compressive stress at (and close to) the wall starts to increase with increasing LOT pressure according to Eq. (2). Analysis of the condition, $\sigma_\theta = p_w$, shows that wellbores in UMS cannot be in tension during LOT unless the well pressure is negative. Therefore, we conclude that except for underbalance drilling, LOT cannot induce vertical fractures in wells that are in a plastic state of stress prior to LOT, which is the case for UMS.

Similar reasoning can be applied to UMS well in the elastic state prior to LOT, i.e. when $p_w > p'_w$. An increase of well pressure to the critical value, p_W'', induces plastic yield in the initially elastic wellbore. Also, tangential stress at the wall reduces to $\sigma_\theta = p'_w$ when $\sigma_r = p''_w$. (Further increase of well pressure would result in the increasing tangential stress.) The critical pressure, p''_w, is determined from combining Eqs. (1), (2) and (5a), as

$$p''_w = \frac{2N\sigma_h + \sigma_0}{1+N} \tag{7a}$$

for, $\sigma_{\theta w} > \sigma_{zw}$; or, $p_W < \frac{3\mu - 1}{\mu}\sigma_h$

$$p''_w = 2\sigma_h - \frac{\sigma_{z0} - \sigma_0}{N} \tag{7b}$$

for, $\sigma_{\theta w} < \sigma_{zw}$; or, $p_W > \frac{3\mu - 1}{\mu}\sigma_h$

Since the minimum value of tangential stress is p'_w, an initiation of vertical fracture requires that $p'_w < 0$. It follows from equation (4) that, $p'_w < 0$; only if, $2\sigma_h < \sigma_0$; or, $\sigma_{z0} < \sigma_0$. However, the values of $2\sigma_h$ and σ_{z0} are generally greater than σ_0 below the depth of two hundred feet in UMS due to its low strength. Hence, unlike for deep wells, an UMS well can not be fractured vertically even if its wall is in elastic state prior to LOT!

The above conclusions have also been supported by results from our analysis with the finite element method described below.

VERIFICATION WITH THE FINITE ELEMENT METHOD

The above analysis is based on the analytical plane strain calculations and, as such, does not describe precisely actual open hole geometry at the casing shoe, shown in Fig. 1. As the open hole section is constrained by the well's bottom and the casing shoe, plain strain considerations seem better applicable in the middle of the open hole section than at its ends. Therefore, our first approach was to replicate results from the analytical modeling using the finite element model at the mid-point of the open hole section.

The model's schematic is shown in Fig.1. We assume no contact stress at the inner boundary, i.e. the surface between the well's cement and rock. Also, we define a cylindrical outer boundary of the rock-well system having an 11-foot radius around the 26- inch well. Deformations at the outer boundary are laterally constrained. (Our preliminary finite element calculations indicated that at the radial distance from a well exceeding five well diameters stresses were almost equal to in-situ stress).

An example calculations, presented here, considered the following UMS properties: Young's modulus = 1.1×10^5 psi; Poisson's ratio = 0.3; cohesion strength = 31.6 psi; and angle of internal friction = 25.4 degrees. The yield criterion is Drucker-Prager criterion with non-associated flow. It has already been proved that this kind of yield criterion is appropriate for modeling yielding of shale (Steiger and Leung, 1988). Also, in this example we consider a 600-psi vertical stress and initial wellbore pressure (prior to LOT) equal to zero.

The plots in Figures 2 and 3 show lateral distributions of three principal stresses at the mid-point of the open hole before (p_W = 0 psi) and during (p_W = 600 psi) LOT, respectively. It is evident from the plot in Fig. 2 that a plastic zone has formed around the wellbore prior to LOT. This plastic failure caused reduction of vertical and tangential stresses near the well. It can also be noticed that both stresses are almost identical within the inner plastic zone, as discussed above. (The interface between the inner and outer plastic zones is marked by the maximum value of tangential stress. Outwards from the outer plastic zone lies elastic zone where vertical stress is constant and equal to vertical stress in-situ.)

The plot of tangential stress in Fig. 3 demonstrates stress conditions resulting from the second plastic failure (re-yielding). This wellbore failed before the decreasing tangential stress became negative, which means that the wellbore wall had never been in tension during this LOT. Consequently, no LOT - induced vertical fracture is possible in this well which agrees entirely with conclusion from the analytical study above.

We also checked values of tangential stresses at the top and bottom of the open hole section where complex geometry precluded an analytical analysis. In spite of stress concentration at these points - shown in Fig. 4 - tangential stress remains positive for p_W = 700 psi thus indicating that no tension exists around the casing shoe. This result further supported our conclusion.

We also checked a possibility of vertical fracture for the elastic borehole when the wellbore pressure before LOT was 150 psi. Again, the finite element simulation showed that the increasing LOT pressure would inflict plastic yield without bringing the wellbore wall to tension.

LOT - INDUCED HORIZONTAL FRACTURE IN UMS

Mechanism of horizontal fracture involves fracture initiation and propagation. The latter is well described by balancing effective wellbore pressure with overburden matrix pressure (or actual well pressure with overburden pressure). On the other hand, mechanism of horizontal fracture initiation is typically addressed by assuming that wellbore liquid somehow invades the rock through pre-existing fractures or discontinuities and without addressing the invasion mechanism. Our assumption regarding non-penetrating fluid precludes such hypothetical speculations and requires some quantitative description of the mechanism of fluid invasion into the rock at the casing shoe.

One such mechanism would be an uplift of the wellhead at sea bottom caused by LOT pressure increase. During LOT the well is shut-in around the drill pipe and pressure pushes the wellhead upwards. As the casing is attached to the wellhead the uplifting of the wellhead may reduce vertical compression at the casing shoe which, in turn, may be transferred to the rock. If the reduction of compressive stress was large enough it would reduce vertical stress at the wellbore wall from compression to tension which would cause horizontal fracture.

Unfortunately, our finite element analysis showed that this uplifting mechanism could only reduce part of vertical compressive stress at the shoe even for a rigid column of casing and cement. Moreover, our numerical calculations showed that vertical compressive stress at the borehole wall would not be reduced to tension even for bottomhole pressure several-fold greater than overburden pressure!

The mechanism that actually initiates horizontal fracture involves uplifting of casing and cement at the shoe. There, drilling fluid can easily go under the cement and casing shoe and push them upwards, as shown in Fig. 5. This uplifting would cause elastic deformation of the bottom portion of cemented casing. The resulting strain is transferred to the rock and may reduce vertical compressive stress at the wall to tension and initiate horizontal fracture. The above mechanism has been confirmed theoretically.

The wellbore configuration used in our finite element studies is shown in Fig. 5. The example well has a casing diameter of 30" and wellbore diameter of 26". The rock properties are: Young's modulus = 1.1×10^4 psi; Poisson's ratio = 0.35; cohesion strength = 9.2 psi; and, internal friction angle = 23 degrees. The cemented casing has Young's modulus = 30×10^6 psi, and Poisson's ratio of 0.3. The value of contact stress is assumed zero. Effective overburden pressure was calculated using average submerged unit weight, 8.345 lb/gal, which represents UMS having a porosity of 61% and wet bulk density, 13.9 lb/gal. During LOT, bottomhole pressure increases from its initial zero value to 145 psi, which roughly corresponds to drilling at 415 feet below the sea bottom.

Shown in Fig. 6 is an effective vertical stress distribution at the borehole wall below the mud line (sea bottom) down to the bottom of open hole. There is a linear increase of vertical stress with depth in the upper section of the well indicating that the well's wall is in elastic state from surface to the depth at which plastic failure occurs. Below this depth vertical stress steadily decreases indicating an expansion of the plastic zone with increasing depth. At the casing shoe there is a dramatic change of vertical stress going from compression to tension caused by LOT pressure (points A-B-C). This change represents conditions for initiating a horizontal fracture at the shoe. This mechanism has been verified with ABAQUS in several simulation runs for varying UMS properties and wellbore conditions, shown in Table 2. All these calculations showed initiation of tensional horizontal fractures during LOTs in UMS.

Once a horizontal fracture is formed at the wall of a well, the drilling fluid will penetrate into it and try to propagate the fracture. As shown above, however, the vertical stress increases in the plastic zone around wellbore with increasing distance from the well to the plastic - elastic boundary where it becomes stress in-situ. Hence, horizontal fracture will not propagate beyond the plastic zone until the actual wellbore pressure is greater than in-situ overburden pressure.

LOT-INDUCED ANNULAR CHANNEL IN UMS

Formation of a vertically upward propagating annular channel around the cemented casing is another potential failure resulting from LOT in UMS. In our recent study, we investigated plastic deformations of the open hole during LOT and concluded that drilling fluid may invade the contact surface between cement and rock at the casing shoe (Wojtanowicz and Zhou, 1996). We also found that the opening gap size might be of the order of 0.01 in. which was within the critical range (0.01-0.015 in.) for drilling fluid's inflow, as determined by other researchers (Morita, 1990). We reached these conclusions from the finite element simulations assuming no bond and no contact pressure existed between cement and rock. We did not, however, address the issue of critical pressure for initiation of the annular channel.

Critical pressure for annular channeling is the minimum bottomhole pressure required to change contact stress at the casing shoe from compression to tension (In order to determine critical pressure one must assume that mechanical continuum exists between cemented casing and rock, which means assuming both a bonding and contact stress.). As critical pressure for channeling may be smaller than the one for horizontal fracture, both critical conditions should be included in the LOT analyses.

Our study of annular channeling involved a finite element analysis of the mechanical model of wellbore shown in Fig. 1. Conceptually, the model is identical to the one for vertical fracture except for a constant non-zero value of contact stress between the cemented casing and rock. Also, geometry of the wellbore is different to that in Fig. 1 with wellbore diameter - 26 in., height (CB) - 60 ft, and radius (DC) - 17.5 ft. Rock properties are the same as those in Fig. 1. The initial value of the bottomhole effective pressure before LOT is assumed zero. Shown in Fig. 7 is the effect of LOT bottomhole pressure on contact stress at the casing shoe. As bottomhole pressure increases from zero to 350 psi, contact stress reduces from 100 psi to zero. Thus at 350 psi annular channeling begins, which means that the critical value of bottomhole pressure is 3.5 - fold greater than the initial contact pressure.

Critical pressure for annular channeling strongly depends on contact stress. Intuitively, the larger the contact stress is, the higher the wellbore pressure is needed to create a channel. We believe that the value of the contact stress depends upon time, formation properties, and to some extent properties of the cement slurry. Although determination of the contact pressure is beyond the scope

of this study, we can estimate its range from zero (for compacted sediments) to horizontal stress in-situ - for very weak sediments. Thus, the maximum value of contact stress is,

$$\delta_c = \sigma_h = \frac{\mu}{1-\mu}\sigma_{z0} \tag{8}$$

where the value of Poison ratio in UMS can be evaluated using recent empirical correlation (Eaton, and Eaton, 1997).

The relationship between the contact stress and the critical pressure for annular channeling is shown in Table 3. As shown in Table 3, in all cases considered in the study, critical channeling pressure was about 3.5 - fold greater than the contact stress. Moreover, with this 3.5 value, the pressure ratio was not affected by varying rock properties such as Young's modulus, Poisson's ratio, internal friction angle and cohesive strength. In addition, vertical stress and wellbore diameter did not affect the ratio, either.

DISCUSSION: APPLICATION TO LOTs IN UMS

Findings of this study are being used in our continuing research project aimed at an improvement in procedures and analyses of LOTs in UMS. There are two potential applications of these results; prediction and diagnosis. Prediction of the type of formation failure; i.e. annular channeling or horizontal fracturing, requires prior knowledge of rock properties, contact pressure, and vertical stress. From this data one can decide if LOT may result in channeling which would potentially lead to the loss of the well's integrity or merely horizontal fracturing which brings about no serious environmental or technical risk.

If the only data available are LOT results, a diagnostic analysis can be performed to decide which type of damage resulted from the test. The analysis would require an estimation of overburden and pore pressure gradients, first. A simple method was proposed for calculating overburden pressure in UMS at depth using a constant representing exponential trend of sediment compaction trend with depth (Bourgoyne, et all, 1991). Also, another proposed method would use data from geotechnical borings offshore to estimate the change of the sediment's bulk density with depth subsea (Bender and Bourgoyne, 1995).

Secondly, a recorded LOT should be analyzed. According to this study we believe that the LOT plots for horizontal fracture and annular channel may have similar shapes showing a pressure increase until a maximum value, $p_{\max}$, is reached and it stays constant. From this plot a failure pressure, p_f, is calculated as

$$p_f = 0.052\rho D_T + p_{\max} \tag{9}$$

Where: D_T (ft) = TVD; and, ρ = mud density.

If the value of overburden pressure, σ_{over}, is known, the decision whether or not a channeling occurs could be based on comparing P_f with σ_{over}. For: $P_f < \sigma_{over}$; a channel might be formed, otherwise - a horizontal fracturing occurs.

For example, there is a LOT for a 24" casing shoe at 803 ft TVD and TMD, mud weight is 9.0 lb/gal, RKB is 118 ft above sea level, mud line is 102-ft below sea level, LOT pressure is 155 psi. The fracture pressure is P_f =(0.052)(9)(803)+155=530 psi. Typical range of UMS bulk density is 11.7 lb/gal -16.7 lb/gal. Thus, the possible range of the overburden pressure values is from the minimum value of [(102)(.44)+(0.052)(803-102-108)(11.7)=] 405 psi, to the maximum value of [(102)(.44)+(0.052)(803-102-108)(16.7)=] 560 psi. The average overburden pressure is (102)(.44)+(0.052)(803-102-108)(14.2)=483 psi. Because the fracture pressure is greater than the average overburden pressure, we can conclude that the maximum strength at the shoe represents an overburden pressure in this area and there is no risk of an upward migration of fluids along the well.

If LOT results indicate annular channeling, preventive or remedial action can be considered. For prevention, a key point is to increase the contact stress between cement and rock by using non-shrinking or expanding cements, for example. Using results from this study an increase of contact stress above 29 percent of overburden pressure should prevent annular channeling. (This safe value of contact stress is smaller than horizontal stress in-situ.)

For this example, to prevent annular channeling, the contact stress should be greater than 153 psi (using 3.5 value of the stress ratio) at the casing shoe with overburden pressure 1000 psi and pore pressure 465 psi. That gives the required value of hydrostatic pressure of cement slurry at the casing shoe greater than 618 psi.

CONCLUSIONS

1. Analysis based on elasto-plastic properties of UMS shows that vertical fractures cannot be induced by LOTs in these type of sediments. Therefore, LOT analysis in UMS cannot be extrapolated from the theory developed for conventional LOTs in deep wells.
2. Of the two types of casing shoe failures during LOT in UMS - initiation of a horizontal fracture or an annular channel, the latter brings about considerable environmental and technical risk of loosing the well's integrity.
3. This study provides conditions necessary to identify the type of casing shoe failure resulting from LOT; If LOT bottomhole pressure stabilized close or above overburden pressure, the casing shoe breaks by horizontal fracture. If the pressure is smaller than overburden pressure the most likely failure is harmful annular channeling.
4. Using the results from this study, an increase of contact pressure above 29 percent of overburden stress should prevent annular channeling, because, as shown here, the average ratio of channeling pressure to contact stress is 3.5 and is little sensitive to other parameters.
5. The determination of contact stress at the casing shoe is critical for predicting type of failure resulting from LOT in UMS. Although the contact stress is usually unknown its maximum value can be estimated from correlation for the in-situ horizontal stress. Wells having the maximum contact stress values slightly above 30 percent of overburden pressure are sensitive to annular channeling and should not be tested to failure.

ACKNOWLEDGMENTS

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SI Metric Conversion Factors

ft	× 3.048	E-01	= m
gal	× 3.785412	E-03	= m^3
psi	× 6.894757	E+00	= kPa

TABLE 1 Values of Yield Pressure Gradients from LOTs in UMS

Property	Unit	LOT1	LOT2	LOT3	LOT4	LOT5
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	psi/ft	1.49	0.84	1.02	0.83	0.94

TABLE 2 Data for horizontal fracture simulation study

CASE	$2r_w$ (in)	E (psi)	μ	φ (deg)	τ_0 (psi)	γ (lb/gal)	E_{cc} (psi)	D (ft)	d_{cc} (in)
1	26	1.1E4	0.4	12.5	11.6	8.35	3E7	400	30
2	26	1.1E4	0.4	12.5	11.6	8.35	3E7	564	30
3	20	1.1E4	0.4	12.5	11.6	8.35	3E7	400	24
4	26	1.1E4	0.4	12.5	11.6	16.7	3E7	400	30
5	26	1.1E6	0.4	12.5	11.6	8.35	3E7	400	30
6	26	1.1E4	0.4	12.5	11.6	8.35	3E8	400	30
7	26	1.1E4	0.4	15.3	11.6	8.35	3E7	400	30
8	26	1.1E4	0.4	12.5	16.6	8.35	3E7	400	30
9	26	1.1E4	0.35	12.5	11.6	8.35	3E7	400	30

TABLE 3 Data for annular channeling simulation study

CASE	E (psi)	μ	φ (deg)	τ_0 (psi)	LOAD (psi)	D (ft)	$2r_w$ (in)	RATIO
1	1.1E5	0.3	25.4	31.6	600	1100	26	3.6
2	1.1E5	0.3	21.6	34	600	1100	26	3.5
3	1.1E5	0.3	25.4	78	600	1100	26	4.3
4	1.1E3	0.3	25.4	31.6	600	1100	26	3.5
5	1.1E5	0.2	25.4	31.6	600	1100	26	3.5
6	1.1E5	0.3	25.4	31.6	600	1100	20	3.5
7	1.1E5	0.3	25.4	31.6	700	1300	26	3.4

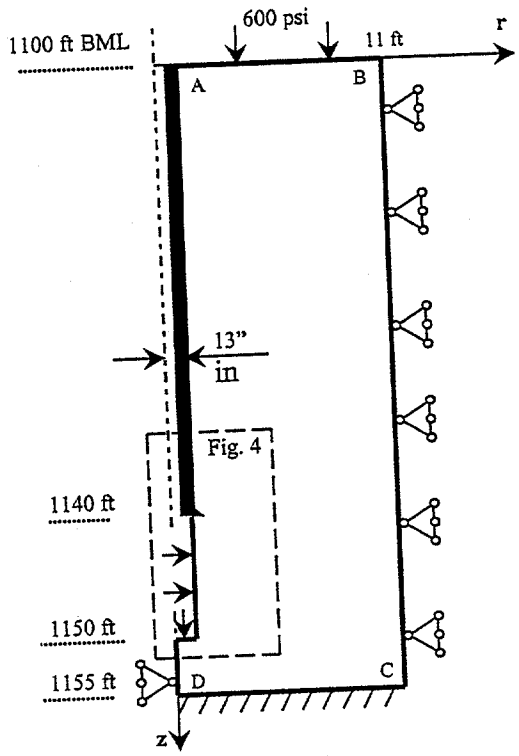

Fig. 1 Model of vertical fracture initiation during LOT

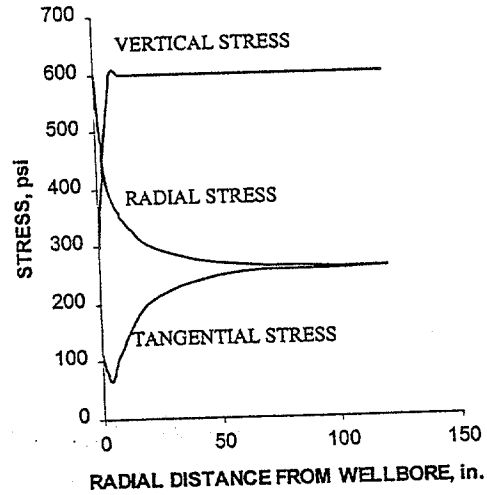

Fig. 3 Plot of tangential stress shows second yield for (600 psi) LOT pressure

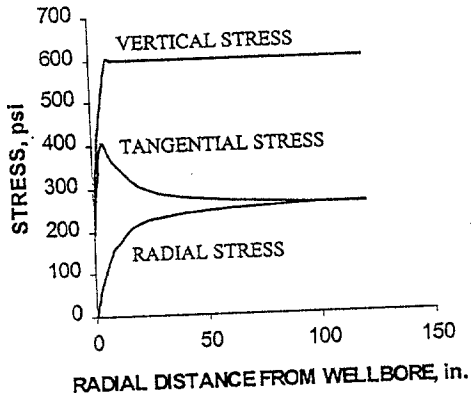

Fig. 2 Distribution of stresses at mid-point of open hole before LOT

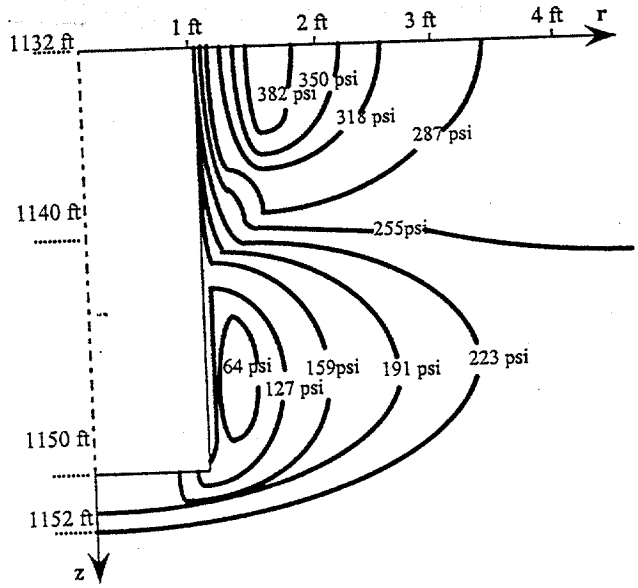

Fig. 4 Concentration of tangential stress at top/bottom of open hole shows no tension during LOT

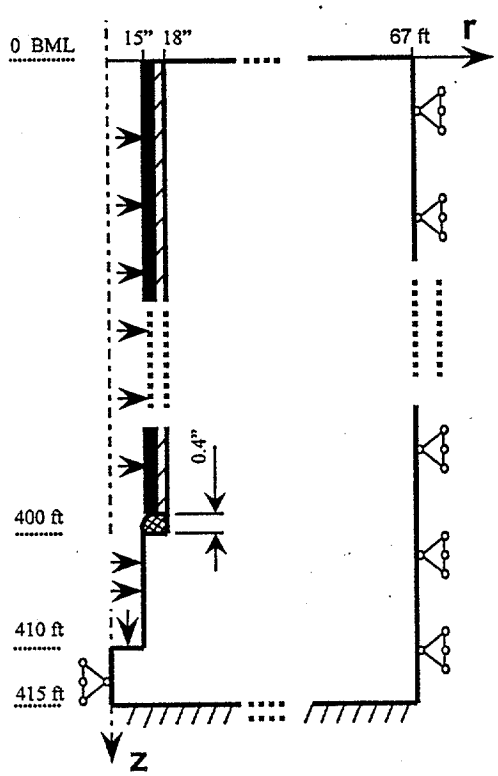

Fig. 5 Model of horizontal fracture initiation during LOT

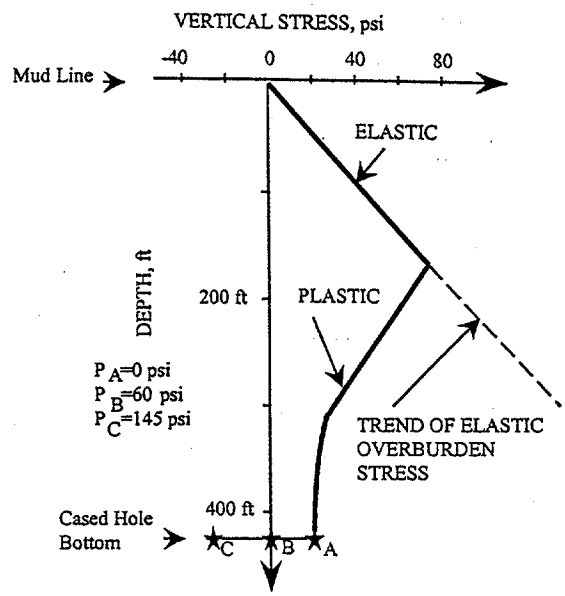

Fig. 6 Vertical stress change shows initiation of horizontal fracture at casing shoe during LOT

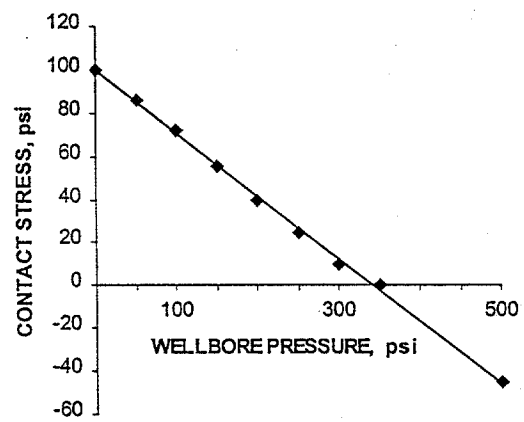

Fig. 7 Contact stress change shows initiation of channel at bottom of cemented casing during LOT

1

BOREHOLE FAILURE RESULTING FROM LEAK-OFF TESTING IN UPPER MARINE SEDIMENTS OFFSHORE

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and
Desheng Zhou

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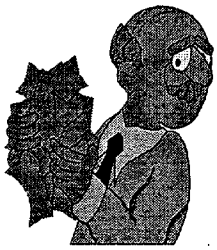
Petroleum Engineering Department

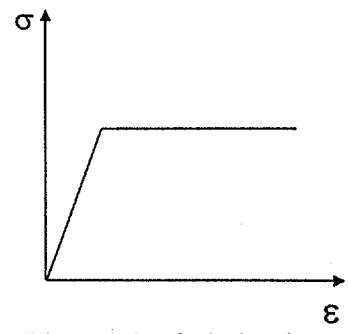
OBJECTIVE



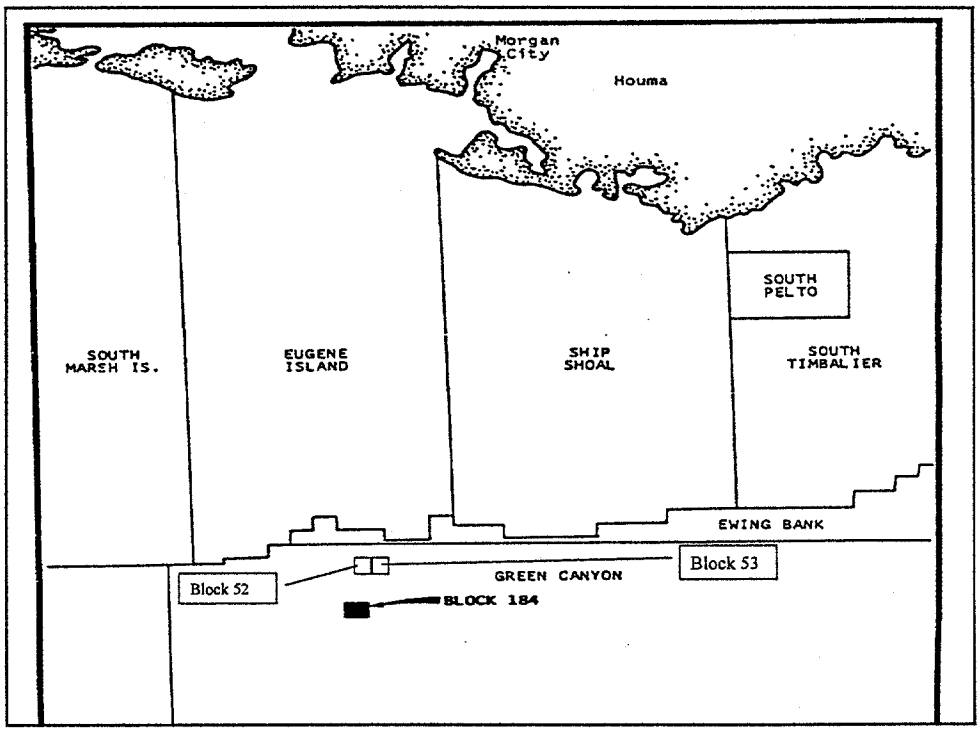
- Theoretically examine leak-off tests (LOT) as a potential source of permanent damage to wellbore external integrity in the upper marine sediment (UMS)

UMS DEFINED

- Water depth: ≅ 10'+
- Sediment depth: ≅ 100-3,000 ft
- Young's model: ≅ 200-200,000 psi
- Poison ratio: ≅ 0.2–0.48
- Angle of friction: ≅ 10–30 degree
- Cohesive strength: ≅ 1–100 psi



Elasto-plastic behavior



ANALYSIS OF GEOTECHNICAL DATA

Previous analysis (Bender et all): Weight/density, Atterberg limits, and shear strength.

This analysis : Young's Modulus, Poisson's Ratio, Cohesion Strength, Friction Angle, and Effective Vertical Stress for 3 Blocks.

METHODS

E, Young' Modulus: from Shear Modulus G. E=2G(1+v). Where G is 1/3 of the slope of consolidated undrained triaxial test curve.

v, Poisson' Ratio: from confined test data; v=k/(1+k), where k is the confined-vertical stress ratio.

Cohesive Strength: equals the unconsolidated undrained shear strength.

Friction Angle: equals Arcsin (maximum shear stress/effective normal stress) from the stress path curves.

Effective vertical stress: is provided directly in geotechnical data.

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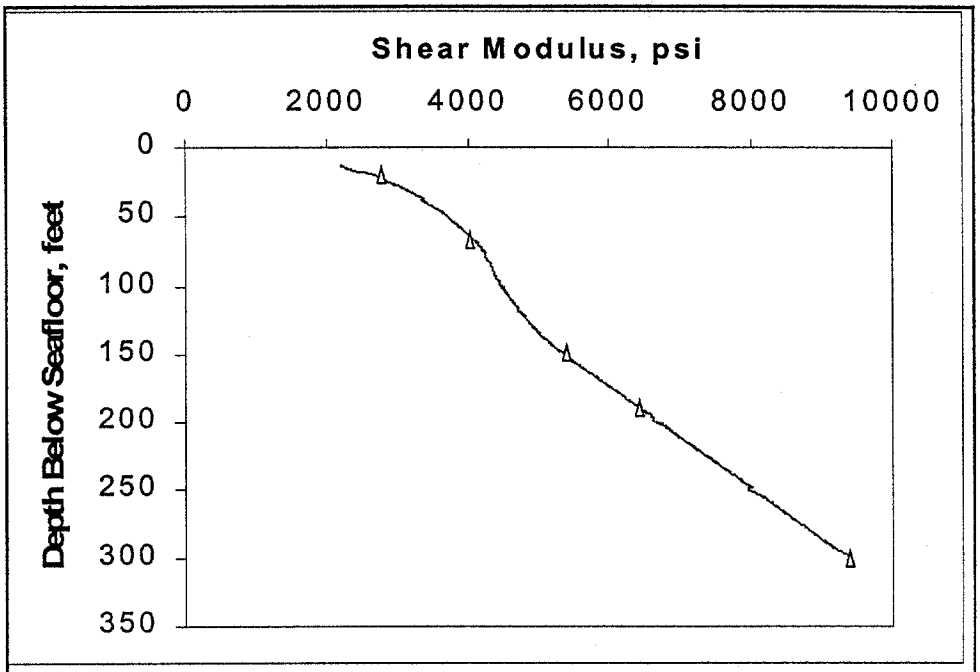
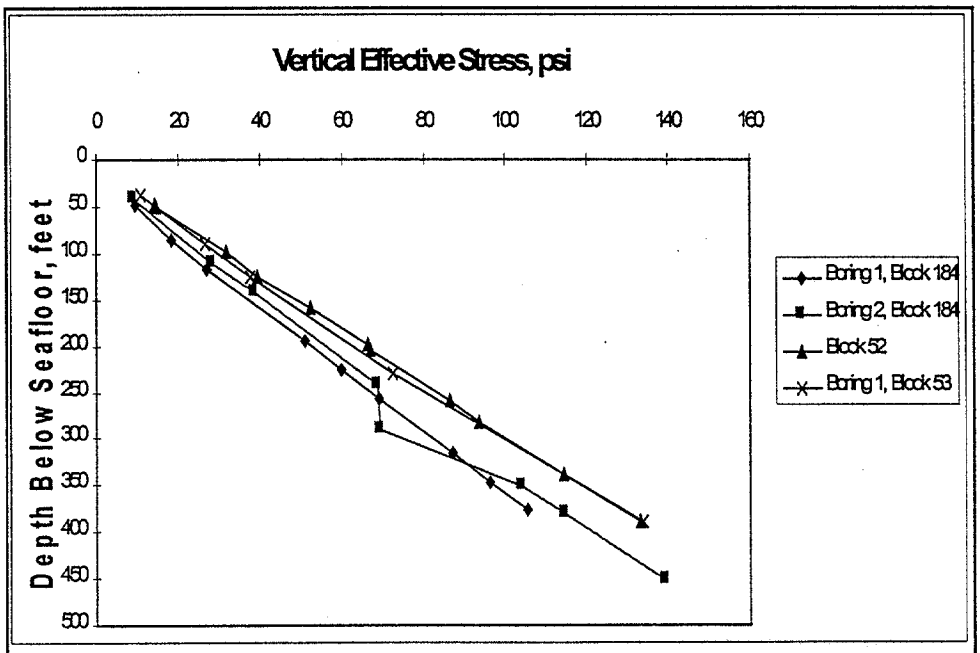
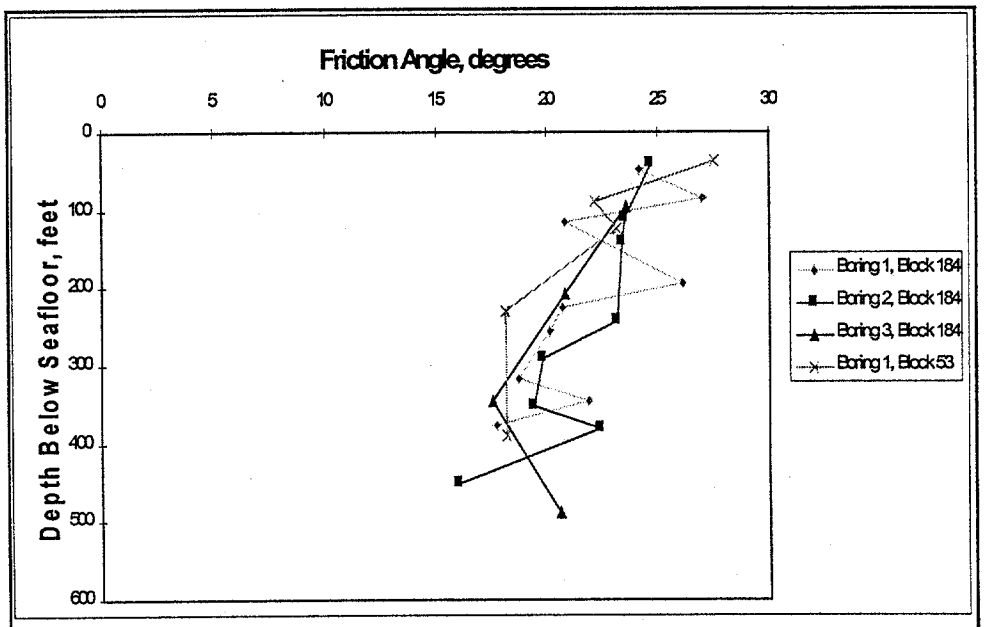


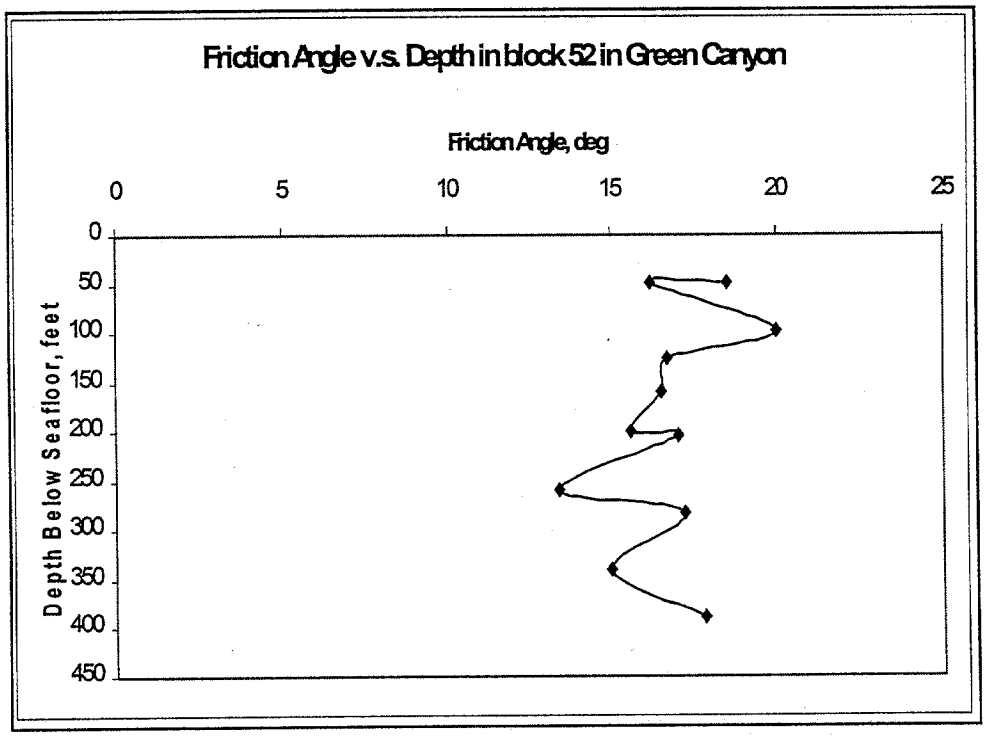
Shear Modulus v.s. Depth in Green Canyon

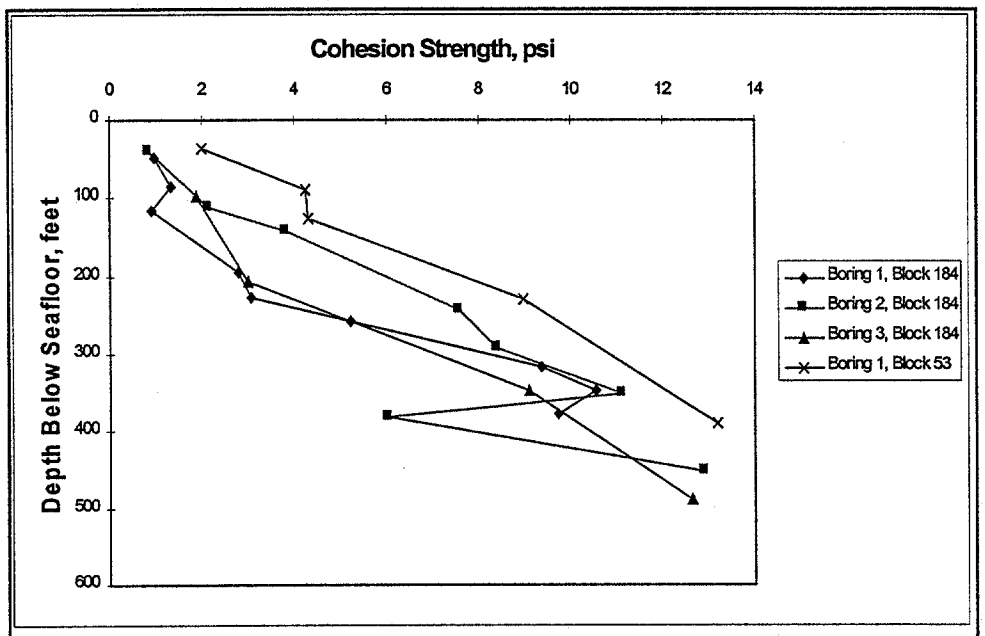


Vertical Effective Stress v.s. Depth in Green Canyon

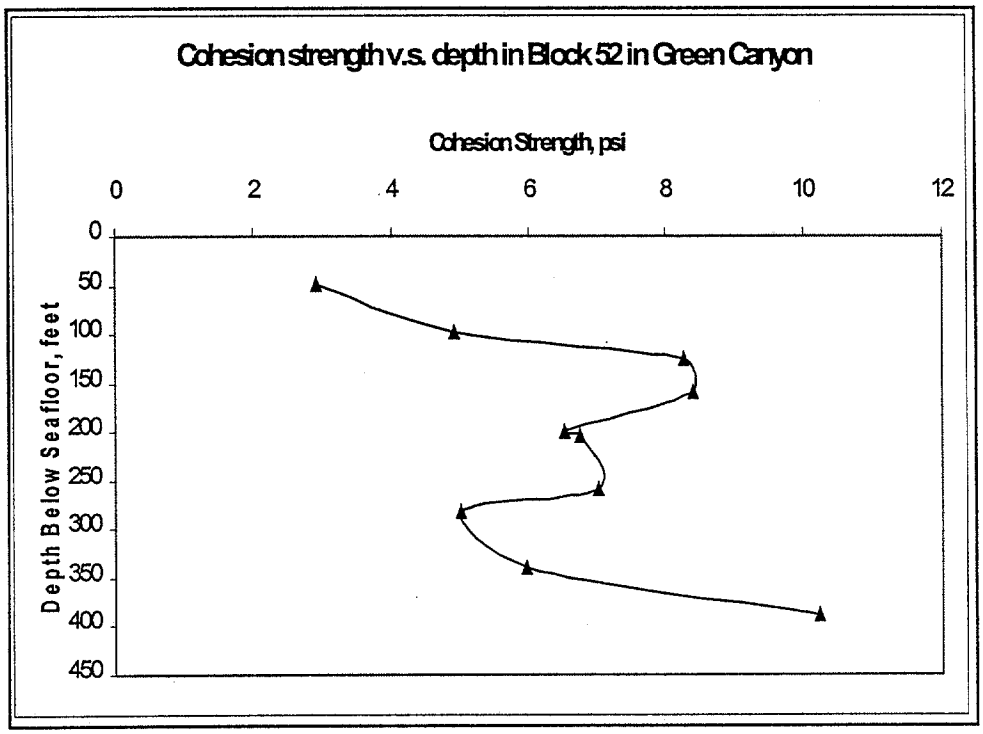


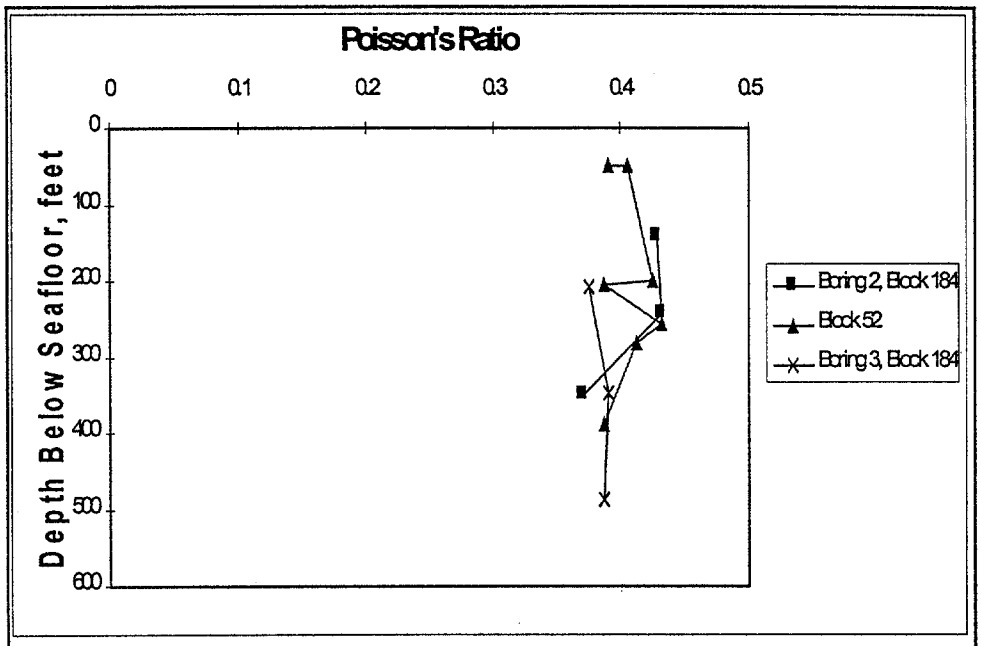
Friction Angle v.s. Depth in Green Canyon Area





Cohesion Strength v.s. Depth in Green Canyon Area

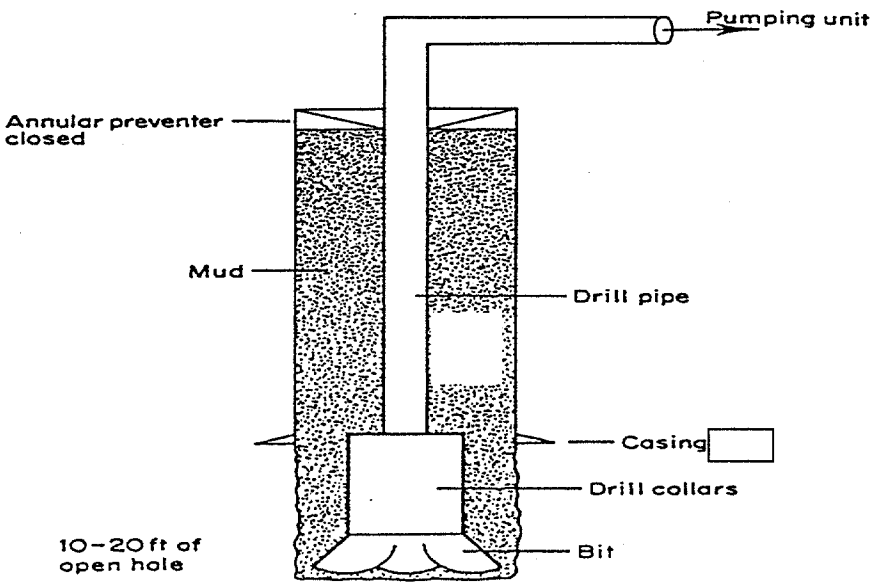




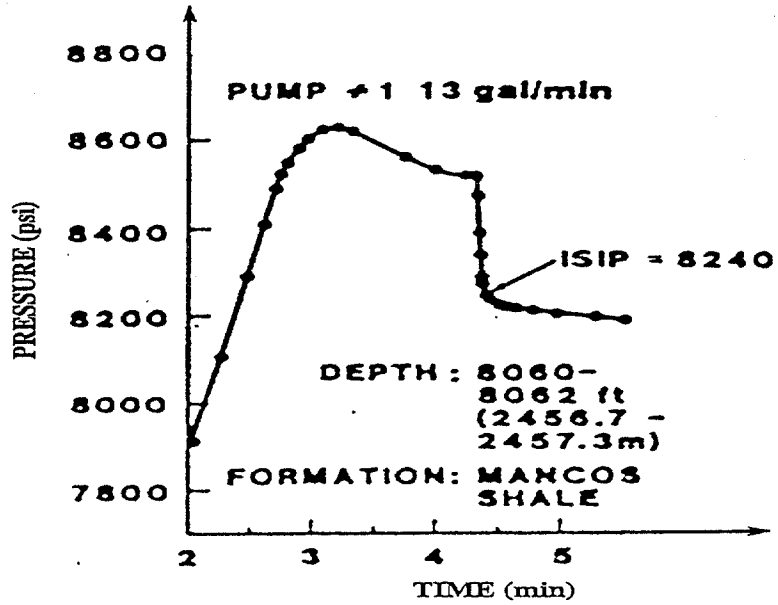
Poisson' ratio v.s. Depth in Green Canyon Area

METHOD

- Analysis of LOTs in UMS: typical features
- Analytical modeling of UMS , verified with Finite Element Method (ABAQUS): in-situ stress ratio, LOT-induced stress, tensional fracture
- Finite Element Modeling: 3-D stress concentrations and deformations.



Schematic drawing of a small fracturing, leak-off or casing seat test assembly.



"Ideal" Test of Hydraulic Fracture Stress

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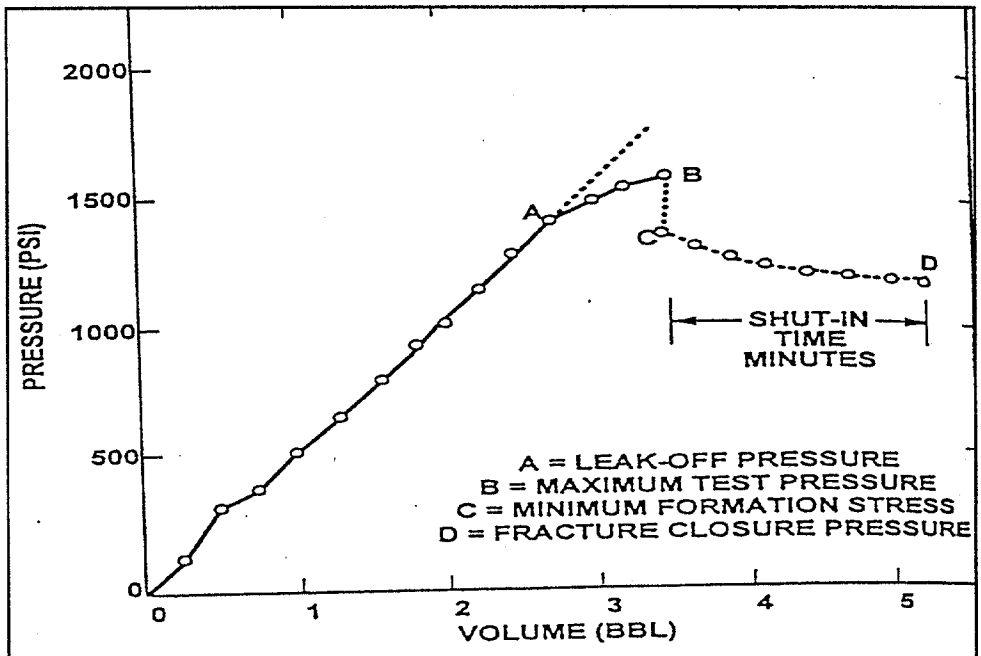
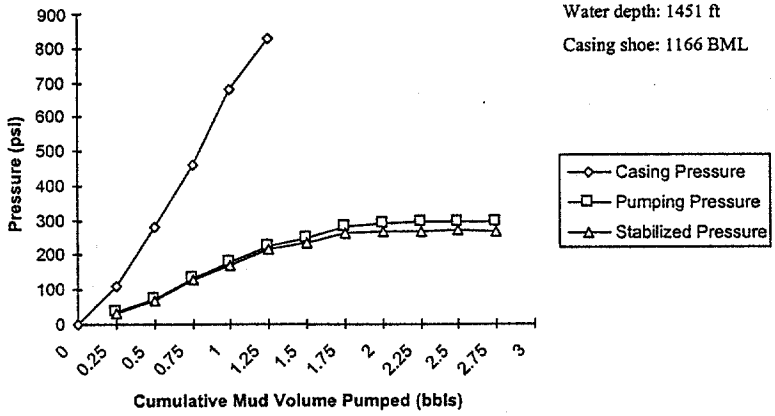


Typical Open-Hole PIT Plot



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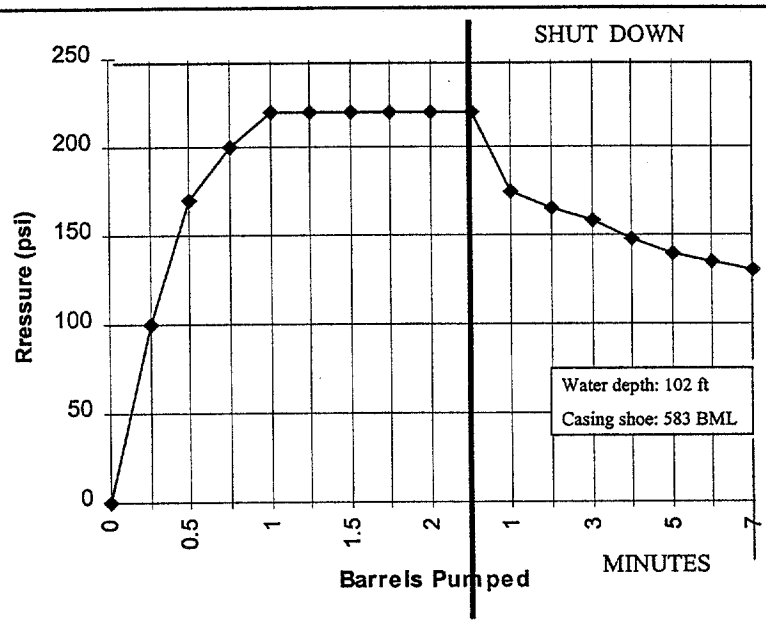

UMS LOT WITH LEAK-OFF

Values of Yield Pressure Gradients from LOTs in UMS

PROPERTY	*LOT1*	*LOT2*	*LOT3*	*LOT4*	*LOT5*
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
Pumped 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	0.83	0.94

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UMS *LOT* PROBLEMS

DIFFICULT AND RISKY:

1. PLOTS ARE NON-LINEAR (NO DEVIATION FROM STRAIGHT LINE);
2. INCONCLUSIVE-NO INDICATION OF LEAK-OFF AND BREAKDOWN.
3. POTENTIALLY DAMAGING TO WELL INTEGRITY. ←

CURRENT FIELD PRACTICES:

- NOT TO RUN LOT IN UMS; or,
- TERMINATE LOT AT LOWER PRESSURE.

Can incidents of flow behind casing be related to LOT?

POSSIBLE FAILURES DUE TO LOT

- SHEAR FRACTURE - eliminated (1996 paper)
- VERTICAL FRACTURE (TENSION) - not possible (1996 paper)
- HORIZONTAL FRACTURE (OVERBURDEN UP LIFT)
- ANNULAR CHANNEL (OPEN HOLE DEFORMATION)

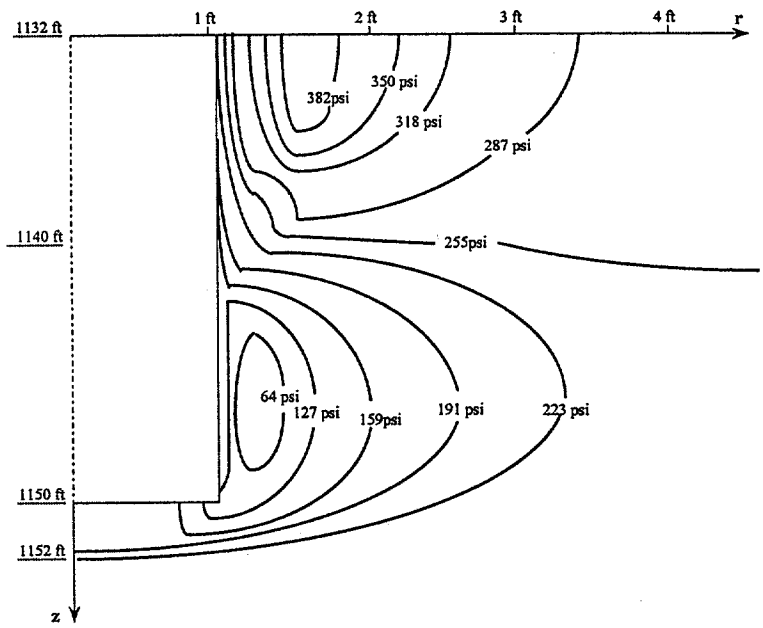
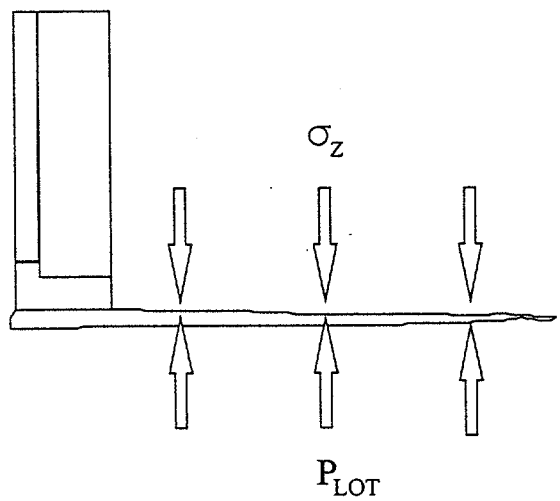


Fig. 4 Concentration of tangential stress at top/bottom of open hole shows no tension during LOT

SOURCE OF HIGH LOT PRESSURE GRADIENT
HORIZONTAL FRACTURE



PROBLEM: FLUID TRANSFER MECHANISM ?

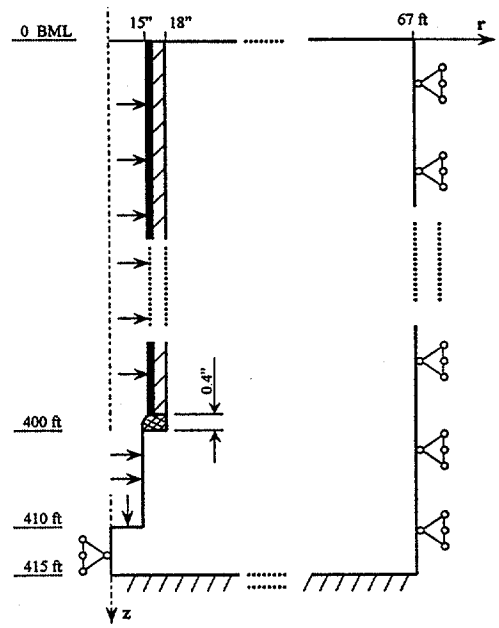


Fig. 5 Model of horizontal fracture initiation during LOT

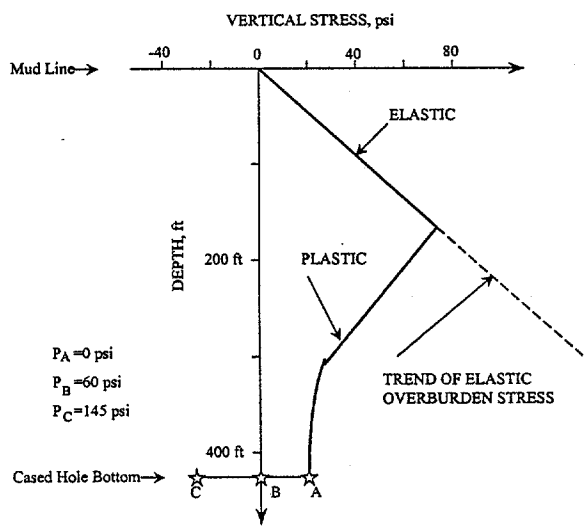


Fig. 6 Vertical stress change shows initiation of horizontal fracture at casing shoe during LOT

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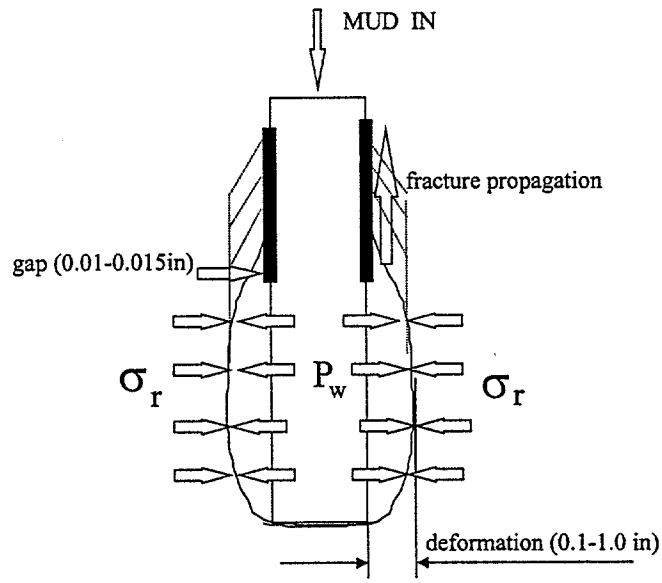
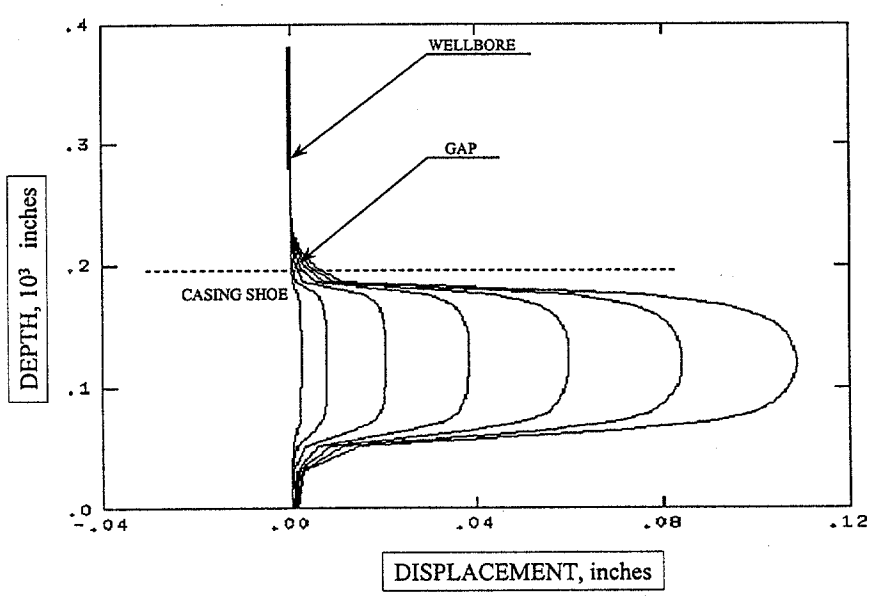
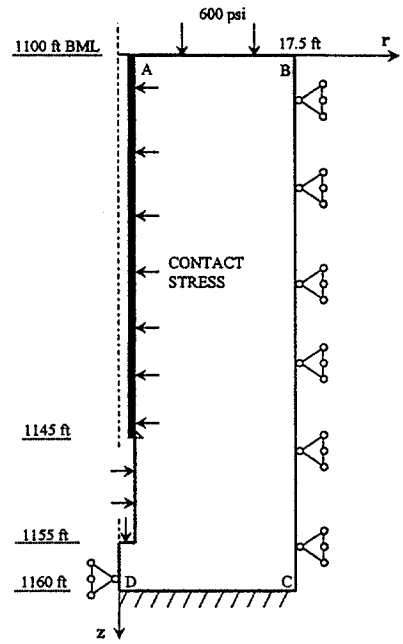
ANNULAR CHANNEL



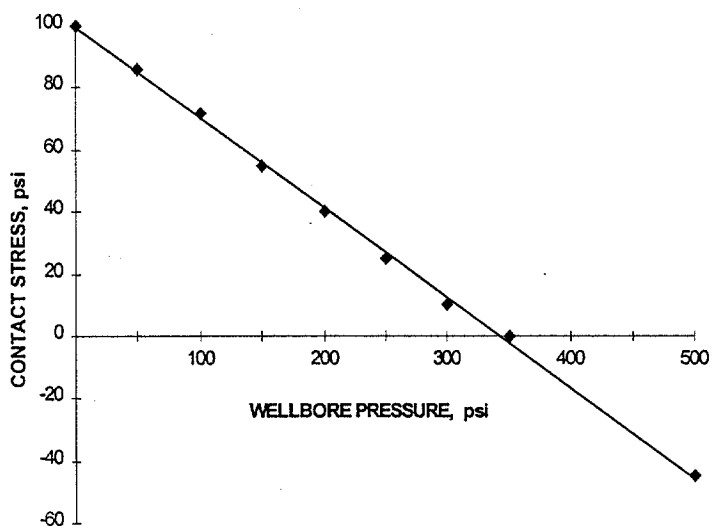
$$\Delta p_{wlot}^{top} = \Delta p_{wlot}^{shoe} - (\Delta p_{mud} - \Delta p_{pore})$$



Deformation of open hole around casing shoe during LOT



Model of annular channel initiation during LOT

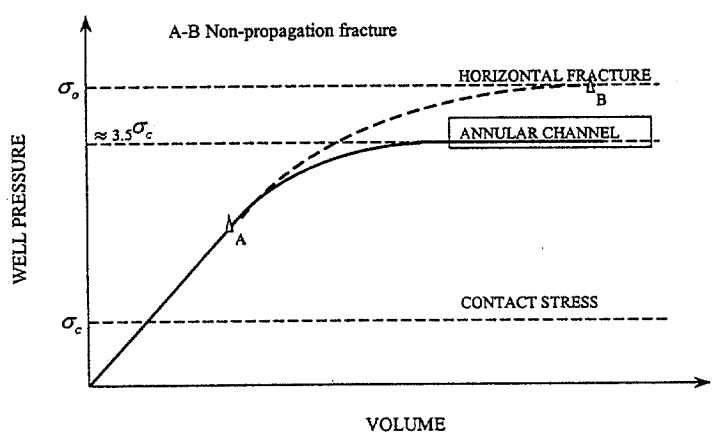


Contact stress change shows initiation of channel at bottom of cemented casing during LOT

CHANNELING PRESSURE V.S. CONTACT STRESS

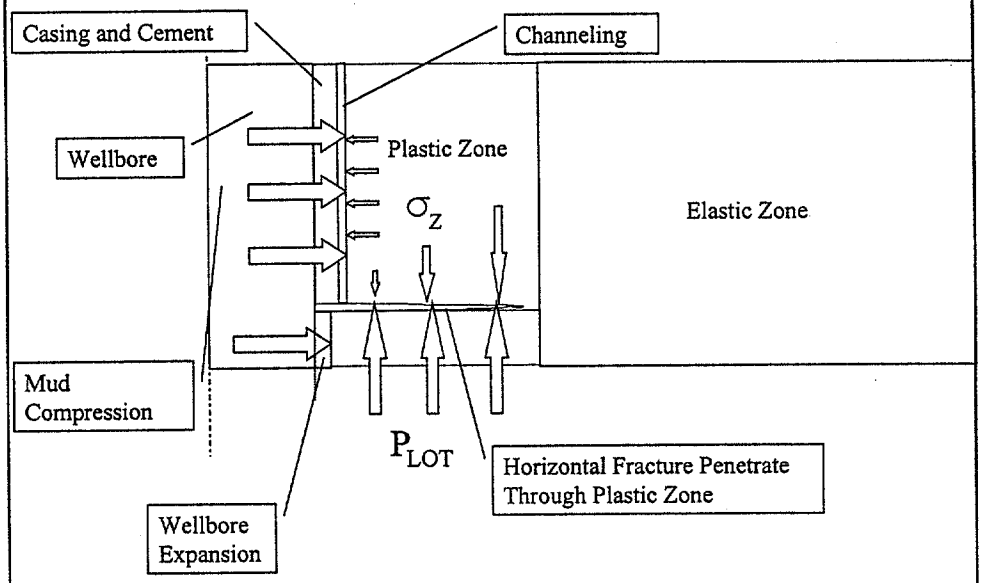
TABLE 3 Data for annular channeling simulation study

CASE	E (psi)	μ	φ (deg)	τ_0 (psi)	LOAD (psi)	D (ft)	$2r_w$ (in)	RATIO
1	1.1E5	0.3	25.4	31.6	600	1100	26	3.6
2	1.1E5	0.3	21.6	34	600	1100	26	3.5
3	1.1E5	0.3	25.4	78	600	1100	26	4.3
4	1.1E3	0.3	25.4	31.6	600	1100	26	3.5
5	1.1E5	0.2	25.4	31.6	600	1100	26	3.5
6	1.1E5	0.3	25.4	31.6	600	1100	20	3.5
7	1.1E5	0.3	25.4	31.6	700	1300	26	3.4



HYPOTHETICAL LOT RECORD SHOWS ANNULAR CHANNEL DEVELOPMENT

VOLUMETRIC RESPONSE TO PRESSURE DURING LOT (No filtration)



VOLUME OF WELLBORE EXPANSION

Method:

Plane strain analytical analysis of a well surrounded by plastic zone.

Assumptions:

1. No-filtration.
2. Plane-strain deformation (2-D analysis).
3. Uniform radial displacement.

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FORMULAS FOR WELLBORE EXPANSION

(Same formulas for elastic and plastic wellbores)

Radial displacement away from wellbore,

$$u = \frac{3\Delta p_w r_w^2}{2Er} \qquad (1)$$

Radial displacement at the wellbore,

$$u_{r_w} = \frac{3\Delta p_w r_w}{2E} \qquad (2)$$

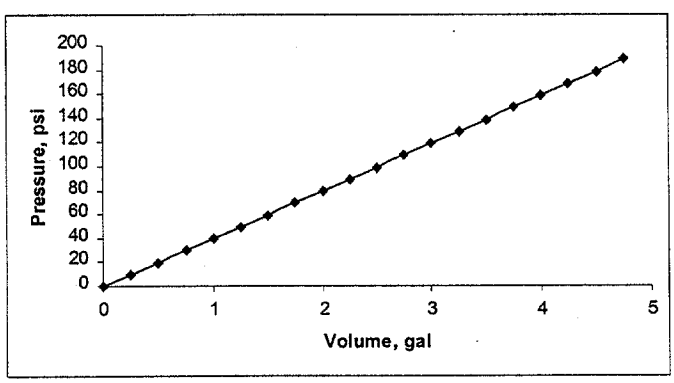
Wellbore expansion volume, bbls

$$\begin{aligned}\Delta V_e &= 2\pi r_w u_{r_w} H * \frac{12}{231} \\ &= 0.49 H r_w^2 \Delta p_w / E\end{aligned} \qquad (3)$$

EXAMPLE OF WELLBORE EXPANSION

Data: D=389 ft; Young's Modulus=32915 psi; Poisson's Ratio=3.9; Wellbore diameter=26"; Effective LOT pressure (wellbore pressure-formation pressure)=133 psi; Open hole height=10'.

$$\Delta p_w = 39.75 \Delta V_e$$



VOLUME OF NON-PROPAGATING HORIZONTAL FRACTURE

Concept:

1. Vertical effective stress in the plastic zone increases from the lower value at the well to the value of in-situ vertical stress away from the well. As LOT pressure increases, a non-propagating horizontal fracture penetrates the plastic zone.

2. The fracture width is controlled by the elastic zone outside the plastic zone around the fracture.

Method:

An equilibrium equation of a penny-shaped crack in a circular cylinder by Sneddon and Lowengrub.

Assumptions:

1. No-filtration.
2. Vertical stress is linear with radius in plastic zone.
3. Mud pressure inside the crack is constant.

FORMULAS FOR NON-PROPAGATING FRACTURE

$$\boxed{V_{hf}(R) = \frac{2}{231}\int_{r_w}^{R}\int_{0}^{2\pi} w(r,R)\,r\,dr\,d\theta = \frac{1}{110}(R^2 + r_w R - 2r_w^2)\,w(r_w,R)}$$

Where:

$$R = \frac{(p_{LOT} + \sigma_o)r_w}{2(p_w + \sigma_o)}$$

$$w(r,R) = \frac{8(1-\mu^2)AR}{\pi E}\Bigg($$

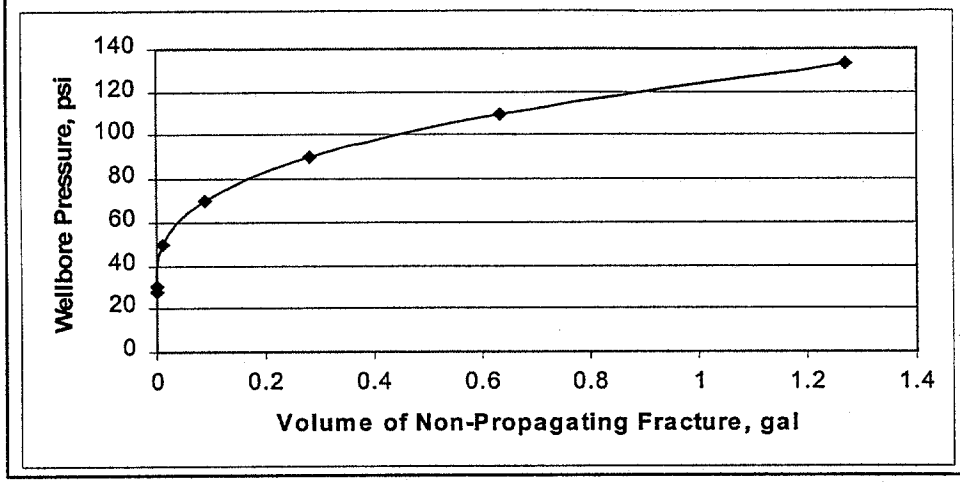
$$\left(1-\frac{f_{rw}}{2}\right)\left(\sqrt{(1-f_{rw}^2)(1-f_r^2)} - \frac{f_{rw}^4\sqrt{(1-f_r^2)^3}}{8f_r^2} - \frac{f_{rw}^2}{2f_r^2}\left(1+\frac{f_{rw}^2}{8f_r^2}\right)\left(\sqrt{(1-f_r^2)^3} - \sqrt{1-f_r^2} + f_r \arctan\frac{\sqrt{1-f_r^2}}{f_r}\right.\right.$$

$$\left. + \frac{f_{rw}^3}{2}\frac{1}{f_r}\,arcsec\left(\frac{1}{f_r}\right) + \frac{f_{rw}^3}{24 f_r^3}\left(\sqrt{1-f_r^2} + \frac{1}{f_r}\,arcsec\left(\frac{1}{f_r}\right)\right)\right.$$

$$\left. - \frac{\pi}{8}\left(\sqrt{1-f_r^2} + f_r^2 \ln\left(\frac{1+\sqrt{1-f_r^2}}{f_r}\right)\right)\right)$$

EXAMPLE OF NON-PROPAGATING FRACTURE

(D=389 ft; Young's Modulus=32915 psi; Poisson's ratio=3.9; Wellbore diameter=26"; Effective LOT pressure (wellbore pressure-formation pressure)=133 psi; H=10 FT.



VOLUME OF ANNULAR CHANNEL

Method:

Channel width is controlled by well pressure. Channel height is controlled by frictional pressure losses (pumping rate).

Assumptions:

1. No-filtration;
2. Uniform channel width-constant pressure gradient;
3. Newtonian fluid in laminar flow.

CHANNEL VOLUME FORMULA

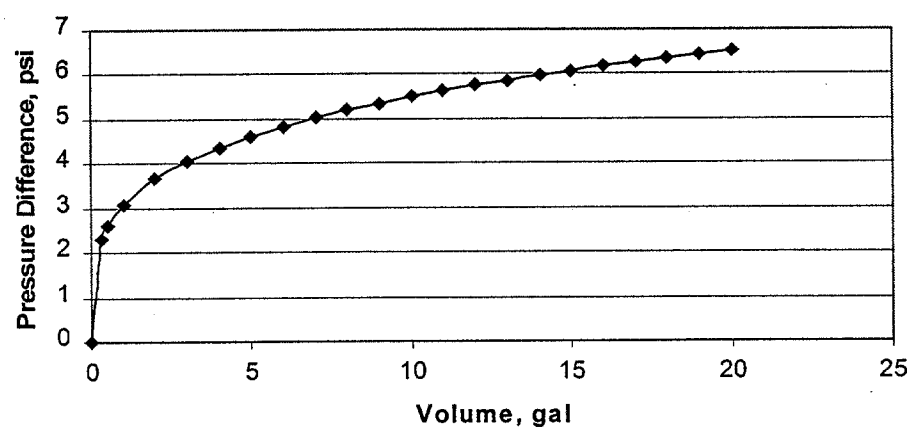
$$\Delta V_c = \frac{12}{231}\pi u d_1 L = \frac{506\, d_1^6}{\mu E^3 q}\Delta p_{wc}^4$$

D=389 ft; Young's Modulus=32915 psi; Poisson's ratio=3.9; Wellbore Diameter=26"; Effective LOT pressure (wellbore pressure-formation pressure)=133 psi; Open hole height=10 ft.

$$\Delta p_{wc} = 3.09\sqrt[4]{\Delta V_c}$$

EXAMPLE OF ANNULAR CHANNELING

The same data as last slide



PREDICTION OF LOT

The LOT plot gives a relationship of pressure v.s. volume pumped. The plot comprises volumetric contributions of the following effects:

1. Combined effect of mud compression and casing expansion. The effect is recorded from casing pressure test.
2. Combined effect of wellbore expansion and mud compression in the open hole. The uncased wellbore expands linearly with pressure. Mud compression is ignored.
3. Volume of a horizontal fracture growing within the plastic zone; or,
4. Volume of a propagating annular channel.

EXAMPLE OF LOT PREDICTION

DATA:

D=389 ft;

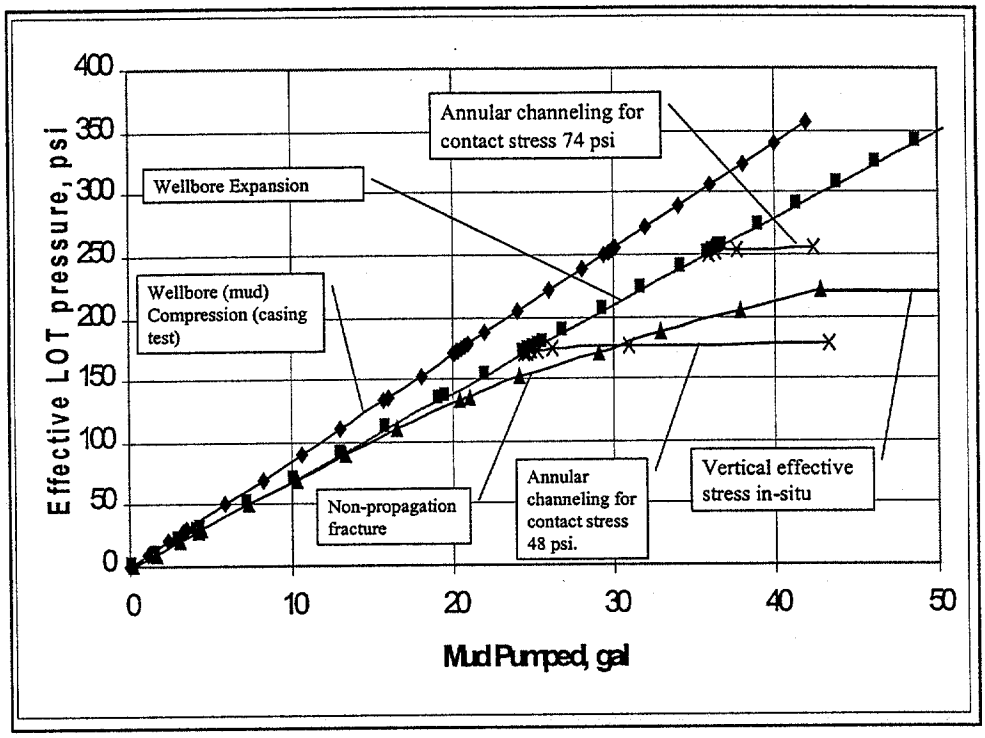
Young's Modulus=32915 psi;

Poisson's ratio=3.9;

Wellbore diameter=26";

Effective LOT pressure (wellbore pressure-formation pressure)=221 psi;

Open hole height=10 ft.



CONCLUSIONS

- **Shear fracture cannot directly result from LOT in UMS - it requires annular channeling and migration of a high-pressure fluid to shallower depths.**
- **Vertical fracture is impossible despite low value of tangential stress in the plastic wellbore.**
- **Of the two possible failures, horizontal fracture or annular channel, the latter is more hazardous. Annular channeling is the most likely when the far-field horizontal stress is less than 29% of overburden stress.**
- **This study gives theoretical basis for analysis of LOT data to decide whether or not the well becomes a hazard for upward migration of subsurface fluids.**

GAS KICKS IN HORIZONTAL WELLS

by
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J. Smith[1], A. T. Bourgoyne[1]
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Introduction

Effective well control practices for underbalanced, horizontal drilling are becoming increasingly important but are not as well developed as for conventional, overbalanced drilling[1]. Underbalanced drilling is being used in an increasing number of wells in many areas of the world. One indicator of this trend is that 25% of all of the wells drilled in the U.S. have a rotating head installed. Drilling underbalanced can provide a number of potentially important advantages versus conventional overbalanced drilling. These include increased well productivity, faster penetration rates, reduced trouble when drilling depleted zones, and an indication of well productivity during drilling.

Horizontal drilling is another technology that is being applied with increasing frequency throughout the world. One operator has reported that over 1800 horizontal wells have been drilled in the Austin Chalk trend in Texas[2]. In many reservoirs, horizontal drilling can provide a longer, higher productivity wellbore than would be possible with a vertical well. This can result in higher production rates, less water coning, improved areal sweep efficiency, and the ability to produce from multiple vertical fractures.

The combination of these two technologies has been particularly successful in some applications. For example, many Austin Chalk prospects, which were uneconomic using conventional drilling practices, have been commercial successes when developed using underbalanced, horizontal drilling. As a result of its unique advantages, underbalanced, horizontal drilling is being applied to deeper, higher pressure, oil and gas reservoirs[2] and even in offshore situations[3].

Well Control Issues Unique to Horizontal Gas Wells

The practice of drilling underbalanced and taking a continuous flow, i.e. kick, from the formation has been very successful in low productivity, moderate pressure, oil reservoirs such as the Austin Chalk in Texas. Adapting this approach to reservoirs that have higher productivity, higher formation pressure, and/or gas as the dominant reservoir fluid has proven more challenging[2]. Higher pressure rotating heads and high capacity mud-gas separation equipment have been applied to address this challenge. Nevertheless, maintaining surface pressures and flowrates within the limits of this equipment has required more careful control of formation influx rates than in less critical applications.

Horizontal gas wells can present additional complications, particularly when sections of the well deviate from horizontal. Substantial volumes of gas can accumulate in the

locations along the length of the test section. A variety of interchangeable injectors can be used to control gas bubble size and injection conditions. A gas separation tank is used at the upstream end to vent counter-flowing gas. Metering of the liquid flow is achieved via a paddle-wheel flow meter with a 0.5% of full-scale accuracy. The gas is metered via an orifice flow meter or a venturi. The test section is isolated from the rest of the system via simultaneously actuated quick closing valves that will be used to trap the two-phase mixture in the test section and determine the average holdup within. In order to make quantitative measurements possible from visual data, an index-of-refraction matched (IRM) segment of the test section has been designed (see Slide 10). Within this segment optical distortion, due to the curvature of the pipe, has been eliminated. This has been achieved by using a pipe material with the same index of refraction as water and immersing this section of pipe itself in a water filled rectangular box. Thus, direct measurements of bubble and plug size and shape are possible from video records of the flow through the use of digital image capturing and processing tools. These measurements can lead to holdup calculation and phase distribution quantification at high holdups (low volumetric flow ratios).

Test Plan

The following test plan for the first phase of the study is in progress:

1. For a given inclination angle and gas injection conditions, the liquid flow rate is held at a fixed value and the gas flow rate will be varied. Conditions under which countercurrent flow is observed will be recorded.
2. Step 1 is repeated for various liquid flow rates up to 160 GPM.
3. Steps 1 and 2 are carried out for three inclination angles up to 30 deg.
4. Steps 1, 2 and 3 are repeated for different gas-injection conditions (location and injector size).
5. Experiments are repeated within the identified counter current flow envelope. During these experiments, (a) video records of the flow using the IRM test section segment is obtained, and (b) average holdup measurements is carried out.
6. The collected data are processed and evaluated. Based on these results additional experiments may be necessary.

References

Bourgoyne, Jr., Adam T.: "Well Control Considerations for Underbalanced Drilling," SPE #38584, '97 SPE ATCE, October 5-8, 1997, San Antonio, Texas.

Joseph, Robert A.: "Underbalanced Horizontal Drilling in an Abnormally-Pressured Environment," #PS.2DT10.001, Petrotech-95.

Nessa, Dag Oluf, et al: "Offshore underbalanced drilling system could revive field developments," World Oil, Part 1 – July 1997, Part 2 – October 1997.

Counter-Current Gas Flow in Horizontal Wells

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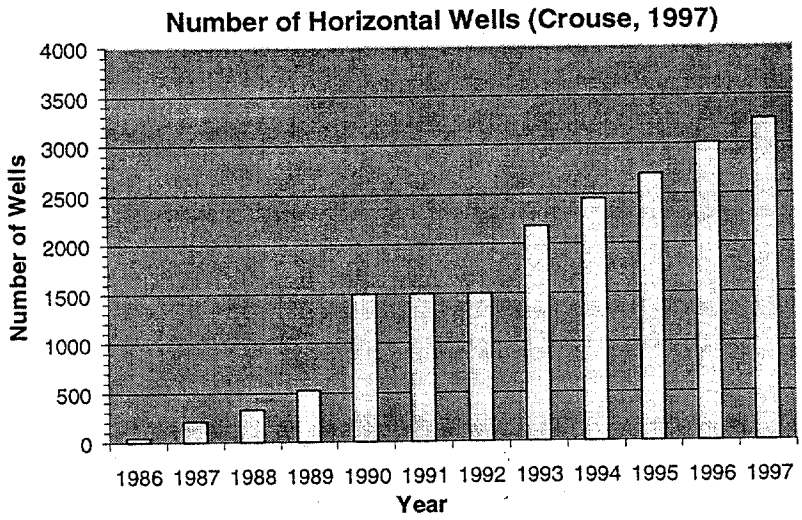
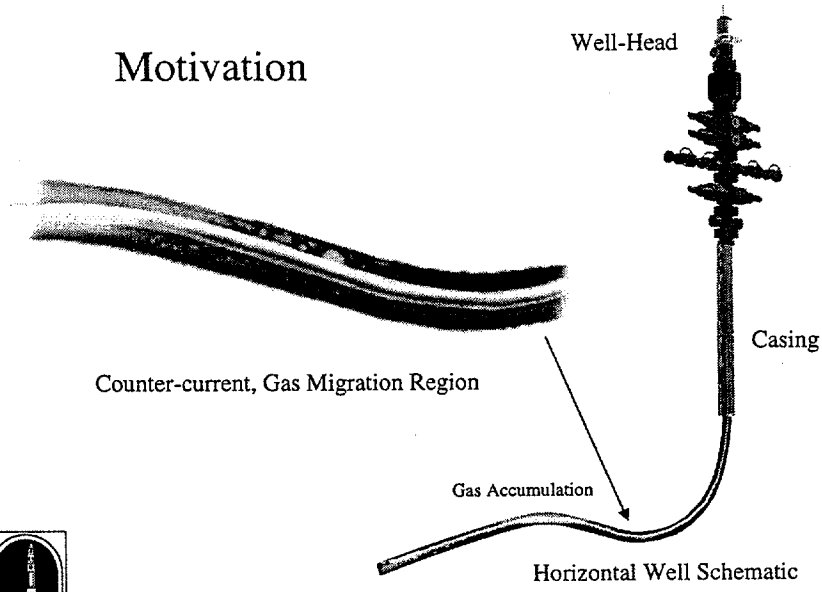
Motivation



Motivation



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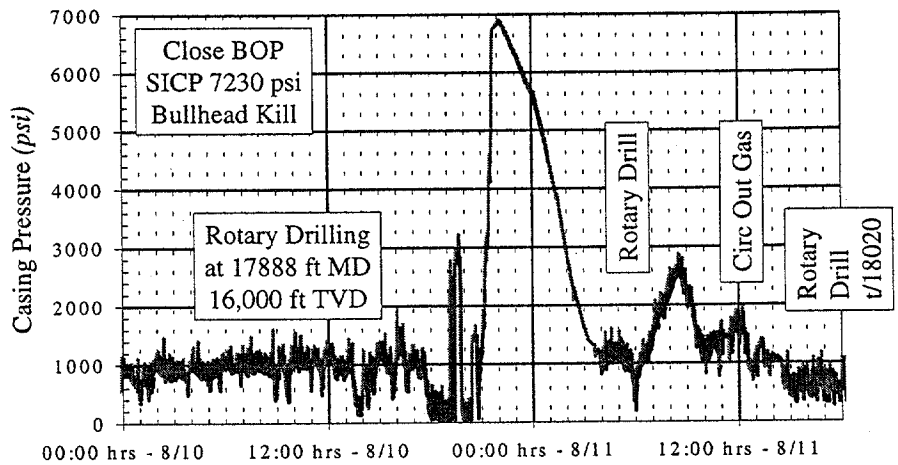
Motivation



Example Kick in Horizontal Well

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Motivation

- Counter-current gas flow
  - is most relevant to Underbalanced and Balanced Horizontal Drilling
  - promotes gas accumulation in the horizontal part of the well which can not be detected on the surface
  - is also relevant to Bullheading operations
- Dangers-High Volume Kicks and Casing Pressures
  - Rapid loss of hydrostatic head will result if/when gas build-up finds its way to the vertical well bore
  - Well highly underbalanced, rapid influx of additional gas
  - High surface flow rates, exceeding equipment capacity
  - High casing pressures, if well is shut in.

Objectives

- Investigate countercurrent, liquid-gas flows in inclined, eccentric annular pipes pertinent to horizontal wells.
  - Experimentally determine the operating window, in terms of liquid and gas superficial velocities, within which countercurrent gas flow occurs at different inclination angles
  - Identify countercurrent/co-current flow regimes
  - Examine the influence of gas injection conditions, and gas bubble size, on this countercurrent gas flow
  - Determine holdup
- Build flow models for new and improved simulations.
- Develop well control strategies and procedures.

Relevant Parameters

- Liquid Superficial Velocity
- Gas Superficial Velocity
- Holdup
- Pipe Inclination
- Pipe Geometry (eccentric annulus)
- Fluid Properties
- Pressure and Temperature

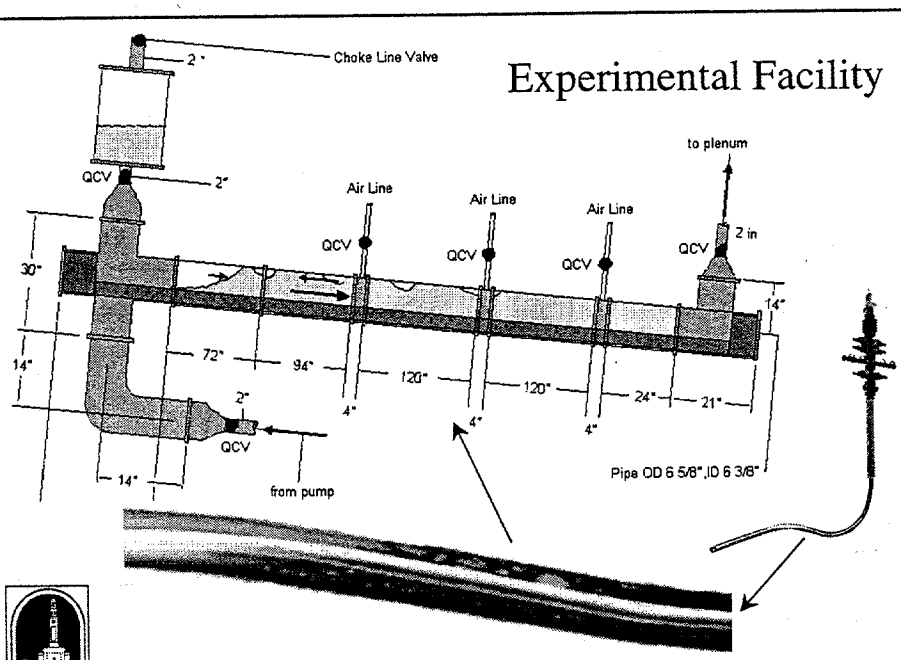
Project Phases

- Phase I
  - experiments with water and air
  - full-scale transparent test section for flow observation
- Phase II
  - polymers added to the water for non-Newtonian rheology
- Phase III
  - drilling mud in non-transparent steel pipe loop

Schedule (Phase I)

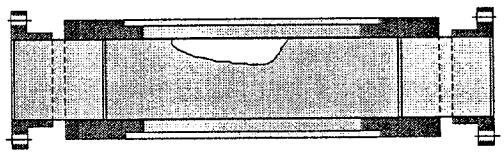
- Design, Build and Instrument Experimental Facility
- Preliminary Qualitative Visualization Experiments
  - Identify Flow Topologies
  - Identify Gas Migration and Distribution Mechanisms
- Quantitative Experiments
  - Measure Superficial Velocities and Holdup
  - Relate to Observations and Build Flow Maps
- Build Simple Models for Simulations

Experimental Facility



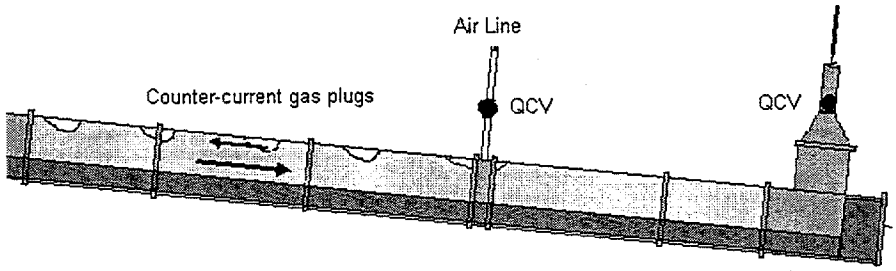
Metering

- Liquid and Gas Flowrates
- Pressures
- Average Holdup (using quick-closing valves)
- Local Holdup (using index-of-refraction matched test-section shown below to remove optical distortion)



Preliminary Experiments

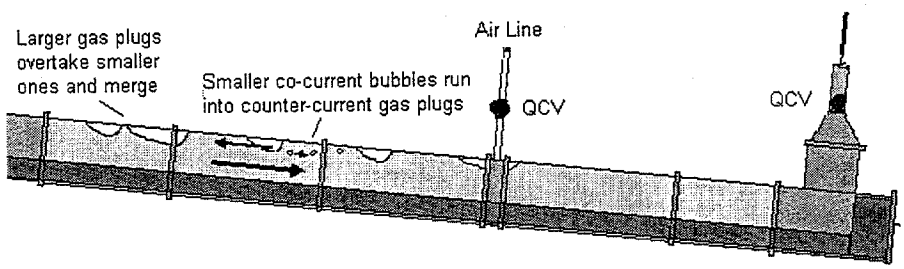
Flow topology observations



Inclination angles > 1.5°
Low Liquid Superficial Velocities (<1.1 ft/sec)
Low and medium Gas Superficial Velocities

Preliminary Experiments

Flow topology observations



Inclination angles > 1.5°

Low Liquid Superficial Velocities (<1.1 ft/sec)

Low and medium Gas Superficial Velocities

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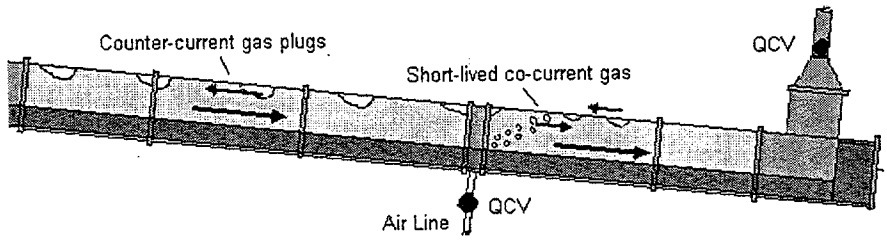
Preliminary Experiments

Flow topology observations



Inclination angle > 1.5°

Low Liquid Superficial Velocity (< 1.1 ft/sec)

Low and medium Gas Superficial Velocities

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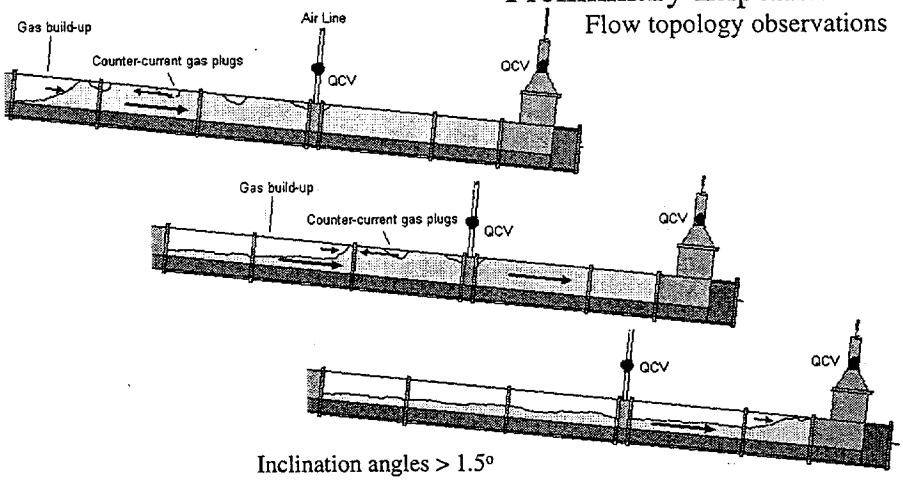
12a

Preliminary Experiments

Flow topology observations



Inclination angles > 1.5°

Low Liquid Superficial Velocities (<1.1 ft/sec)

Low and medium Gas Superficial Velocities

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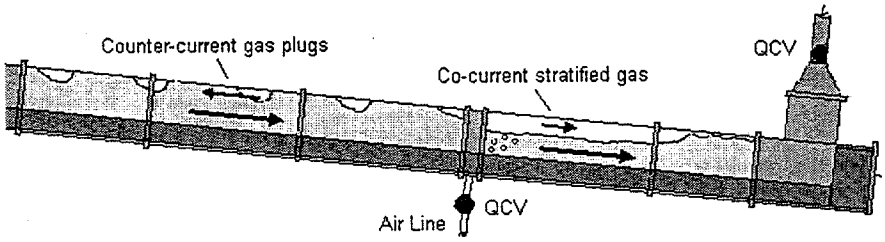
Preliminary Experiments

Flow topology observations



Inclination angle 3°

Medium Liquid Superficial Velocity (1.8 ft/sec)

Low and medium Gas Superficial Velocities

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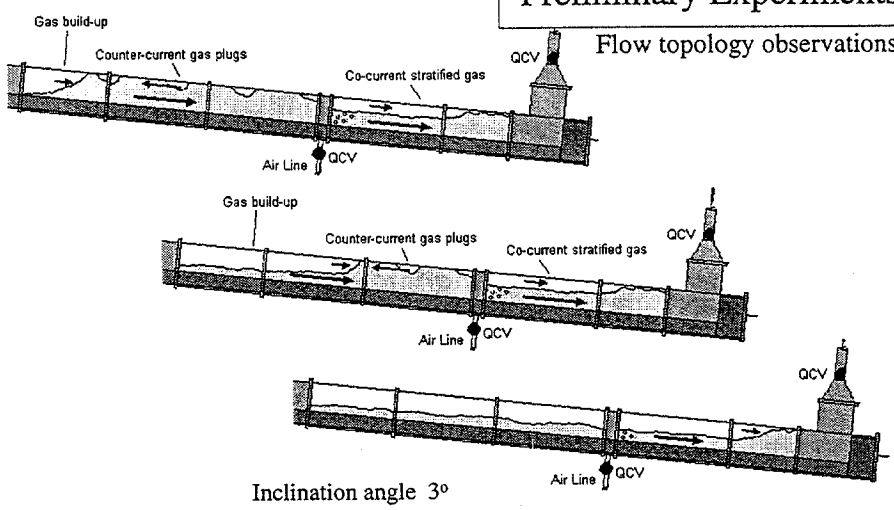
Preliminary Experiments

Flow topology observations



Inclination angle 3°

Medium Liquid Superficial Velocity (1.8 ft/sec)

Low and medium Gas Superficial Velocities

What we have learned so far

- At low liquid superficial velocities (1 ft/sec) all of the gas injected goes counter-current
- This is true even for inclination angles as low as 1.5°
- Up to medium liquid superficial velocities (1.8 ft/sec) considerable counter-current gas flow occurs even at small inclination angles

Future Research

- Conclude Present Task (Phases I, II, III)
- Other problems that will be studied using present facility
  - Bullheading in vertical wells (how to force gas back down the wellbore and into the formation)
  - Bullheading in directional wells with undergrownd blowout