SECOND EDITION

BLOWOUT AND WELL CONTROL HANDBOOK



ROBERT D. GRACE

GPP

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PREFACE

Well control problems are always interesting. The raw power that is released by nature in the form of an oil or gas well blowing out of control is awesome. Certainly, well control is one thing, and WILD well control is something else. There will be well control problems and wild wells as long as there are drilling operations anywhere in the world. It just goes with the territory.

The consequences of failure are severe. Even the most simple blowout situation can result in the loss of millions of dollars in equipment and valuable natural resources. These situations can also result in the loss of something much more valuable—human life. Well control problems and blowouts are not particular. They occur in the operations of the very largest companies and the very smallest. They occur in the most complex operations such as deep, high-pressure gas wells, and they occur in the simplest shallow operations. Men have lost their lives when things went wrong at surface pressures of 12,000 psi and at surface pressures of 15 psi. The potential for well control problems and blowouts is ever present.

Time really flies! Once I was young and now I am old. It seems to have happened in the twinkling of an eye. But, a lot has transpired in between. Through those years, I had the privilege of being involved in most of the industry's most monumental and public well control events, including the Al-Awda Project—the oil fires of Kuwait—and the tragedy on the Deep Water Horizon, the Macondo blowout. I worked on every major blowout in Canada since Lodgepole including Old Salty, the industry's oldest that blew out in 1916 on the Peace River in northern Alberta. I've been involved in the evolution of oil well firefighting on one side of the equation and the introduction of engineering into well control and helped pioneer the technical aspects of well control.

Lots has happened since this text was last updated. The most significant is this. All the Lions are gone! We've lost the icons of the well control industry.

I started as a drilling engineer for Humble Oil and Refining, the forerunner of Exxon, in Oklahoma City. We were working in the Arkoma Basin and were drilling with air. Of course, every well was a blowout with the only difference being how big. I recall some that had fire out the end of the blooie line as high as the crown on the derrick! I learned a lot about well control but nothing about classic procedures since these were no classic operations.

Shortly after that, I left Humble and a few short months later started in the consulting business in the Texas Panhandle. There were two consultants in all of western Oklahoma and the Texas Panhandle—me and CW Kelly. Kelly had most of the business but I squeaked by.

Around the Panhandle and western Oklahoma, it was common practice to drill into the Morrow sands without setting a protective string. The Morrow was an abnormally pressured stratigraphic sand and was unpredictable. As a result, it was standard operating procedure to drill into the Morrow without setting casing on top. Every effort was made to minimize exposure. The plan was usually to drill no more than a couple of feet of any drilling break in the Morrow and then circulate to see if it could be managed. The wells could not be shut in as there was always only a few hundred feet of surface pipe set and thousands of feet of normally pressured interval between the casing seat and the Morrow.

Most often, the permeability in the Morrow was low and the deliverability equally low. We could handle the gas we encountered. But, pretty regularly, we would hit a good Morrow sand that gets our hats blown off! About all you could do was be rigged up with a good choke and separator and let it blow to the pit until you could get it killed. I was very frustrated because we didn't have the technical skills to know how much mud density and pump rate we needed to kill the well. Oftentimes, the well would just blow whatever we pumped back into our faces until after many trial and error efforts, we randomly landed on the right combination of mud weight and pump rate.

I remember one when we worked on for a small company out of Dallas called Filon Exploration. We worked for the nicest guy in Texas, but he didn't know much about drilling and nothing about well control. We were drilling a Morrow well near Higgins, Texas, and we had only a short string of surface casing set. We were getting close to the Morrow, and I called our contact and told him that if we found what we were looking for, were going to get our butts blown off. Our contact told me that we were offsetting a well that had no Morrow and you could throw a rock and hit that location. I told him that didn't mean anything in the Morrow, and we had better get rigged up to handle some gas. He asked what we needed. I told him a good separator, choke manifold, drilling choke, and nailed down flow lines. He said he would call me back.

He called back and told me he had talked to the drilling contractor and the drilling contractor assured him that if we did hit some gas, we could rig all that stuff up. I told him that was not right, but we would do whatever he wanted.

I called our guy at the rig and told him to put a note on the board in the dog house to drill no more than 2 ft of any drilling break from that point forward. He did.

Later that night, I got a call from our guy. The driller had drilled 26 ft of Morrow sand in 18 min. He said we had about 800 psi on the casing. It was a few days before Christmas. I kissed my wife goodbye and told her I didn't know when I would be back. I had not had to miss Christmas at home but was sure this was to be the first.

I went to the rig. I called Jerry and he met me there. We got rigged up and opened the well up through the chokes. It was screaming! We had a BIG Morrow well. We rigged up and pumped 16 ppg mud at about 13 bpm. The well never blinked! We regrouped and called the office. Our contact said we were not doing it right because we were losing circulation and should be pumping 12 ppg mud! We about fainted. Jerry told him he was not sure what would work but that would not work. Filon backed off and let us go back to work. We got all the hydraulic horsepower we could find, went back out to the well, mixed up a few hundred barrels of 20 ppg mud, pumped it at 20 bpm, and killed the well.

I sadly lamented to Jerry that Filon would insist that we work over Christmas. We got it killed and cemented the drill collars about 3:00 am on Christmas Eve. We were sitting in the trailer at the rig. Jerry asked the Halliburton engineer how long we should wait on the cement. The engineer paused and thought for a minute. Jerry interjected and proceeded to remind him how much work GSM did around the Panhandle during the course of the year. Jerry told him that if Halliburton ever wanted to do another job for GSM, his answer would be 72 h! The engineer thought for a minute and then said—I think we should wait on cement about 72 h! We then called Filon. Of course, they wanted us to go to work immediately to which we replied, we wanted to go to work too but Halliburton said we needed to wait on the cement for 72 h. Filon reluctantly agreed and we went home for Christmas.

That job made a big impression on me. I resolved to solve those fluid dynamic mysteries in the future. When I was at Humble, I learned that there was a big separation between operations and engineering. When I got to the field, I found that chasm was the greatest in well control. No one even attempted to apply engineering principles to well control events beyond the classical well control procedures. I harbored the opinion that blowouts were no different than any other engineering problem. We just often didn't have a lot of data to work with which meant our zone of uncertainty would be bigger.

Gone is Preston Moore—Mr. Drilling! Preston pioneered adult education and authored the first texts on drilling engineering. No one was better known or more respected throughout the industry than Preston. Preston was my mentor in college and friend until he passed away in early 2015 at the age of 91. He was the "M" in my company, GSM.

Of course, Dub Goins was the first to recognize and write about the principles we now consider classical well control procedures. I was just getting out of school. Preston was still at OU and heavily involved in continuing education with his *Drilling Practices Seminar*. Preston trained literally thousands of drilling engineers and field personnel.

I worked with Preston at the time he was teaching his seminar, but my first love was working in the field. Preston added a section in his seminar on well control. Through my association with Preston, I was exposed to the latest in fluid dynamics and the fundamentals of classical well control.

As any novice will know, multiphase flow is an interesting and complicated subject. The only work done on multiphase flow in the oil field has been done in gas lift operations. All multiphase calculations are based on research done around oil, gas, and water flowing up small pipes. No work had ever been done on flow in an annulus.

We were hampered in the early days by the lack of computing power. In those days, laptops were just someone's imagination, and a handheld calculator that had a square root function was rare. It was not until 1975 when I went to Montana Tech that I bought an HP-41C that would make all the calculations that could be done on a slide rule.

Gone is my friend of 30 plus years—Bob Cudd. I talked to Bob almost every day and sometimes more than once per day. I first met Bob when he was at Otis. After he left Otis, I tried to hire him but he was too smart for that. He went on to found Cudd Pressure Control. We were a team—the first to offer full services well control operation. We worked together on many difficult jobs—often after others had failed. I trusted Bob's judgment more than my own. I didn't always agree with him but I knew he was always right. I once decided Bob knew more than anyone else in the industry about what he did. I later decided that wasn't true. Bob knew more than everyone else put together in the industry about what he did! I miss him every day.

Gone is Pat Campbell, another friend of many years. I always looked forward to seeing Pat every year at OTC. He would come by my booth or I would go by his. Pat was a gentleman and more than competent on any location under any circumstances. We worked together on some tough jobs. Pat was an icon.

Gone is Red Adair. Red was one of the pioneers of oil well firefighting. Red started out with Halliburton and went to work for Myron Kinley. It was Myron's dad that started modern oil well firefighting early in the last century. In the late 1950s, Red left the Kinley organization and started his own company. He was soon joined by Coots Mathews and Boots Hanson. We always referred to Red as the PT Barnum of our industry. He was not only very capable and innovative but also a showman. I had the pleasure of meeting those three while still in college. They came to OU for our engineer's week celebration in the spring of 1960. They were all driving new red Cadillacs. That impressed a bunch of broke engineering students. As of this writing, Boots is retired and Coots has passed away.

Safety Boss in Canada is still in business. They are the oldest well control company in business. Mike Miller is the principal in Safety Boss. They do things differently from the Houston guys, but their procedures are very effective. Fact is, they fixed more blowouts in Kuwait than any of the others.

In short, there are no real wild well fighters left. The wild well fighting companies have been swallowed up by corporate conglomerates. Organizations like that are more interested in providing services that are needed every day rather than services that are needed only rarely. And, not many are interested in working on blowouts. For long periods of time, there is nothing going on, and then for a long period of time, things are very intense. Often, the job is half way around the world, goes on for days or maybe months, and is under adverse working and living conditions. Not everyone is interested in working like a sled dog and living like a coyote for long periods of time. Not everyone is interested in working regardless of whether it is Christmas or their kid's birthday.

What does all of this mean for the future of the industry? It means that the quality of the services will go down and the costs will increase. As Red Adair once said, "If you think professionals are expensive, wait till you see what amateurs will cost you!" Brightly colored coveralls and hard hats do not make a wild well fighter. There won't be any more men like Red Adair, Coots Mathews, Boots Hansen, and Bob Cudd who devoted their lives and careers strictly to wild well control. It will be interesting. I hope this book will contribute to the future of the industry. I dedicate this book to my old friend Bob Cudd and all the Lions. It was a pleasure and an honor to know and work with them.

ACKNOWLEDGMENTS

I would like to acknowledge my contributors, Mr. Bob Cudd, Mr. Jerald L. Shursen, and Mr. Richard Carden. As a close and personal friend and associate for more than 30 years, Bob Cudd contributed not only to this writing but also much more to the total experience in this work. I once reflected that Bob knew more than anyone about various aspects of well control. I later realized that he knew more than everyone else combined. Bob represented a wealth of experience, knowledge, and expertise. Bob has passed away and is sorely missed every day.

I would also like to acknowledge Jerry Shursen for his contributions. As a close and personal friend, business partner, and associate, Jerry and I worked very closely together to pioneer many of the concepts presented in this book. Jerry is the best drilling engineer I ever encountered in the industry. There is no one I'd rather have beside me in a tough situation than Jerry Shursen.

Richard Carden has been my friend and associate since his student days at Montana Tech. He is an outstanding engineer, and we have worked together on some very tough projects. I have yet to find anything he can't do. Rich is technically solid and has worked diligently to contribute to this book and ensure the quality of the work.

For his inspiration, I would like to acknowledge my lifelong friend Dr. Preston L. Moore. No one has contributed more to drilling than Preston. He was my mentor in college more than 50 years ago. Though he has passed away, he continues to inspire me today. In the late 1960s, in Preston's world-renowned *Drilling Practices Seminar*, he and I were pioneering many of the well control concepts and techniques now considered classic in the industry.

Finally, I would like to acknowledge the staff at GSM who have worked diligently and with professional pride to ensure the quality of this work. Particularly, I must mention and thank my friend, assistant, and secretary Ms. Angie Vigil. Among many other things, she patiently worked through the many details. Finally, I would like to acknowledge my grandson, Quinn Spellmann. At this writing, Quinn is a junior in Petroleum Engineering at Colorado School of Mines. Using his knowledge of modern technology, Quinn worked diligently to improve the quality of the figures, photos, and illustrations.

CHAPTER ONE

Equipment in Well Control Operations

"... I could see that we were having a blowout! Gas to the surface at 0940 hours."

0940 TO 1230 HOURS

Natural gas was at the surface on the casing side very shortly after routing the returning wellbore fluid through the degasser. The crew reported that most of the unions and the flex line were leaking. A $3\frac{1}{2}$-in. hammer union in the line between the manifold and the atmospheric-type "poor-boy" separator was leaking drilling mud and gas badly. The separator was mounted in the end of the first tank. Gas was being blown from around the bottom of the poor-boy separator. At about 1000 hours, the motors on the rig floor began to rev as a result of gas in the air intake. The crew shut down the motors.

At 1030 hours the annular preventer began leaking very badly. The upper pipe rams were closed.

1230 TO 1400 HOURS

Continuing to attempt to circulate the hole with mud and water.

1400 TO 1500 HOURS

The casing pressure continues to increase. The flow from the well is dry gas. The line between the manifold and the degasser is washing out and the leak is becoming more severe. The flow from the well is switched to the panic line. The panic line is leaking from numerous connections. Flow is to both the panic line and the separator.

The gas around the rig ignited at 1510 hours. The fire was higher than the rig. The derrick fell at 1520 hours.

This excerpt is from an actual drilling report. Well control problems are difficult without mechanical problems. With mechanical problems such as those described in this report, an otherwise routine well control problem escalates into a disastrous blowout. In areas where kicks are infrequent, it

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is common for contractors and operators to become complacent with poorly designed auxiliary systems. Consequently, when well control problems do occur, the support systems are inadequate, mechanical problems compound the situation, and a disaster follows.

Because this book is presented as a blowout and well control handbook, its purpose is not to present the routine discussion of blowout preventers (BOPs) and testing procedures. Rather, it is intended to discuss the role of equipment, which frequently contributes to the compounding of the problems. The components of the well control system and the more often encountered problems are discussed.

The saying "it will work great if we don't need it!" applies to many well control systems. The fact is that, if we don't ever need it, anything will suffice. And therein lies the root of many of the problems encountered. On a large number of rigs, the well control system has never been used and will never be needed.

Some rigs routinely encounter kicks, and the crew is required to circulate out the kick using classical well control procedures. In these instances, the bare essentials will generally suffice. For most of these conditions, well site personnel need not be too concerned about how the equipment is rigged up or how tough it is.

In some parts of the industry, wells are routinely drilled underbalanced with the well flowing. In these cases, the well control system is much more critical, and more attention must be paid to detail.

In a few instances, the kick gets out of control, or the controlled blowout in the underbalanced operation becomes uncontrolled. Under these conditions, it is sometimes impossible to keep the best well control systems together. When it happens, every "i" must be dotted and every "t" crossed.

Unfortunately, it is not always possible to foretell when and where one of those rare instances will occur. It is easier and simpler to merely do it right the first time. Sometimes, the worst thing that can happen to us is that we get away with something we shouldn't. When we do, we are tempted to do things the same way over and over and even to see if we can get away with more. Sooner or later, it will catch up with the best of us. It is best to do it right the first time.

PRESSURE, EROSION, CORROSION, AND VIBRATION

When everything goes to hell in the proverbial hand basket, our first question should be, "how long is all this s—going to stay together?" The answer to that question is usually a function of the items listed above—pressure, erosion, corrosion, and vibration.

Pressure

If the well control system is rated to 10,000 psi and has been tested to 10,000 psi, I'm comfortable working up to that pressure provided none of the other three factors is contributing, though that is seldom the case. There is usually a large difference between the working pressure and test pressure for a given piece of equipment. For example, a 10,000 psi working pressure BOP has a test pressure of 15,000 psi. That means the rams should operate with 10,000 psi, and under static conditions, everything should withstand 15,000 psi.

Wellheads, valves, and all other components are the same. It is easy to understand how a valve can have a "working" and a "test" pressure, but it is natural to wonder how a spool can have a "working" and a "test" pressure. Since a spool has no moving parts, it seems that the two should be the same.

Vibration

When things begin to vibrate, the working pressure goes down. There are no models available to predict the effect of vibration. All connections have a tendency to loosen when vibrated violently. As will be outlined in Chapter 9, at the E.N. Ross, a chicksan on a pump in line on the rig floor vibrated loose during the final kill attempt. Due to the presence of hydrogen sulfide, the gas was ignited and the rig was lost.

Erosion

Erosion of the well control system is the most serious problem normally encountered. When circulating out kicks and bubbles in routine drilling operations, erosion is not generally a factor. The exposure time is short, and the velocities of the fluids are minimal. Therefore, almost any arrangement will suffice. It is usually under adverse conditions that things begin to fail. That is the reason most well control systems are inadequate for difficult conditions. Difficult conditions just do not happen that often.

In the time frame of most well control incidents, dry gas simply does not significantly erode, at least nothing harder than N-80 grade steel. At a production-well blowout in North Africa, the flow rate was determined to be approximately 200 mmscf along with about 100,000 bbl of oil per day. The well flowed for almost 6 weeks with no significant erosion on the wellhead or flow lines. Thickness testers were used to monitor critical areas and showed no significant thickness reduction.

At a deep blowout in the southern United States, the flow rate was determined to be well over 100 mmscfpd through the $3\frac{1}{2}$ in. drill pipe by 7 in. casing annulus. The flowing surface pressure was less than 1000 psi. There was great concern about the condition of the drill pipe: would it be eroded or perhaps even severed by the flow? After about 10 days exposure, the drill pipe was recovered. At the flow cross, the drill pipe was shiny. Other than that, it was unaffected by the exposure to the flow.

Unfortunately, the industry has no guidelines for abrasion. Erosion in production equipment is well defined by API RP 14E. Although production equipment is designed for extended life and blowout systems are designed for extreme conditions over short periods of time, the API RP 14E offers insight into the problems and variables associated with the erosion of equipment under blowout conditions. This recommended practice relates a critical velocity to the density of the fluid being produced. The equations given by the API are as follows:

$$V_e = \frac{c}{\rho^{\frac{1}{2}}} \tag{1.1}$$

$$\rho = \frac{12,409\, S_l P + 2.7\, R S_g P}{198.7\, P + R T z} \tag{1.2}$$

$$A = \frac{9.35 + \frac{zRT}{21.25\, P}}{V_e} \tag{1.3}$$

where

V_e = fluid erosional velocity, ft/sec
c = empirical constant
= 125 for noncontinuous service
= 100 for continuous service
ρ = gas/liquid mixture density at operating temperature, lb/ft^3
P = operating pressure, psia
S_l = average liquid specific gravity
R = gas/liquid ratio, ft^3/bbl at standard conditions
T = operating temperature, °R
S_g = gas specific gravity
z = gas compressibility factor
A = minimum cross-sectional flow area required, in^2/1000 bbl/day

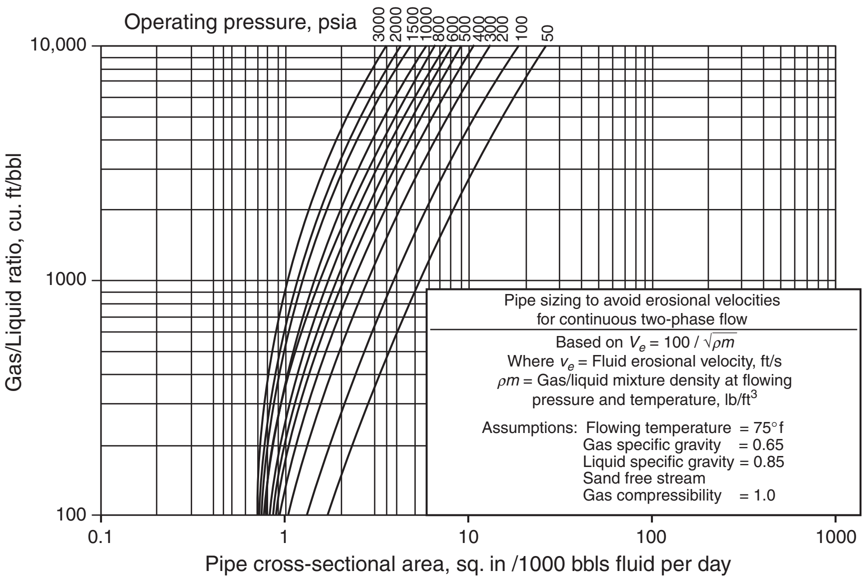


Fig. 1.1 Erosional velocity chart.

Eqs. (1.1)–(1.3) have been used to construct Fig. 1.1, which has been reproduced from API RP 14E and offers insight into the factors affecting erosion. Because the velocity of a compressible fluid increases with decreasing pressure, it is assumed that the area required to avoid erosional velocities increases exponentially with decreasing pressure.

It is, however, interesting that pursuant to Fig. 1.1 and Eqs. (1.1)–(1.3), a high gas/liquid ratio flow is more erosive than a low gas/liquid ratio flow.

The presence of solids causes the system to become unpredictable. Oilfield service companies specializing in fracture stimulation and those involved in slurry pipelines are very familiar with the erosional effects of solids in the presence of only liquids. Testing of surface facilities indicates that discharge lines, manifolds, and swivel joints containing elbows and short-radius bends will remain intact for up to 6 months at a velocity of approximately 40 ft/s even at pressures up to 15,000 psi.

Further tests have shown that, in addition to velocity, abrasion is governed by the impingement angle or angle of impact of the slurry solids and the strength and ductility of the pipe and the hardness of the solids. At an impingement angle of 10 degrees or less, the erosion wear for a hard, brittle material is essentially zero. In these tests, the maximum wear rate occurred when the impingement angle was between 40 and 50 degrees.

The wear rate increased when the solids in the slurry were harder than the tubular surface. Sand is slightly harder than steel. Barite is much less abrasive than hematite.

There is no authority for the erosion and wear rate when solids such as sand and barite are added to gas and drilling mud in a blowout or a well control situation. There can be little doubt that the steels are eroding under most circumstances. API RP 14E merely states that the empirical constant, c, should be reduced if sand production is anticipated.

Solids in the flow stream can be disastrous for the well control system. One case in point occurred at the Apache Key 1–11 in Wheeler County, Texas. Many called the blowout at the Key the biggest blowout in the history of the state of Texas. It was certainly one of the most baffling, spectacular, and unpredictable. With over 90 ft of Morrow sand and an open flow potential in excess of 90 mmscfpd, the Key was one of the best wells ever drilled in the Anadarko Basin. On 4 Oct. 1981, while waiting on pipeline connection, the well inexplicably erupted, launching the wellhead, 80 ft of $2\frac{7}{8}$ in. tubing, 80 ft of $7\frac{5}{8}$ in. casing, and 12 ft of $10\frac{3}{4}$ in. surface casing. The well flowed essentially unrestricted into the atmosphere.

The Key was routinely capped by the end of October. However, 3 days later, the well cratered. All the vent lines were opened in an attempt to relieve the pressure. As illustrated in Fig. 1.2, the 45 degree turns were cut out completely. In addition, a close look at Fig. 1.2 shows that the $7\frac{1}{16}$ in. by 10,000 psi valve body to the vent line had also cut out.

The capping stack was removed, and the well continued to flow, while subsequent well control operations were conducted. The particulate from the well had a distinctive color and was identified as coming from a zone that was originally separated from the flow stream by the tubing and two strings of casing.

At another point in the control operation at the Key, a 20 in. by 10,000 psi stack was being rigged up to cap the well. Due to the size and weight, the stack had to be placed onto the well in sections. While bringing the second section into place, the crew noticed that the bolts in the first section were loose. The first section was removed and examined. As illustrated in Fig. 1.3, the casing head was cut out beyond the rig groove. This severe erosion had taken place in the time required to make up the bolts on the spool and pick up the second section, which could have been no more than a couple of hours.

Time and again, the flow from the Key demonstrated its devastating nature. When the momentum kill procedure was implemented, several

Fig. 1.2

joints of $5\frac{1}{2}$ in. casing were run into the $7\frac{5}{8}$ in. casing. There was a 10,000 psi gate valve on top of the $5\frac{1}{2}$ in. casing. After the momentum kill was accomplished, the well remained dead for about 1 h, and then flow commenced again. The valve lasted only a few minutes. The connections of the $5\frac{1}{2}$ in. casing had been eroded to the extent that the threads on the pins were visible through the boxes. Imagine! All that from a cased hole!

The inside of all the equipment in the stack and the flow lines had to be protected with a special stellite material. Toward the end of the well control operations, an average of 2000 yd^3 of particulate material was being separated from the flow stream and removed each month.

Fig. 1.3

Wells do not have to be deep and high-pressured to demonstrate such fury. On 12 Mar. 2000, a well located near Tabor, Alberta, Canada, got out of control, despite being only 3500 ft deep and normally pressured. The volume rate of flow was estimated to be between 20 and 40 mmscfpd.

Within 30 min after the blowout, holes are eroded in the choke line, filling the manifold house with gas. Later inspections revealed several holes in the choke manifold. One is shown in Fig. 1.4. Within 2 h, the drilling cross cut out (Fig. 1.5).

Fig. 1.4 *(Reproduced with permission from Conoco Canada Limited.)*

Fig. 1.5 *(Reproduced with permission from Conoco Canada Limited.)*

When the wellhead was removed several days later, it was paper thin (Fig. 1.6). After the well was killed by the relief well, the casing at the surface was found to be eroded and too thin to support a capping stack.

Formation solids are the usual culprits in problems with erosion. However, mud solids are also erosive. Barite will erode, and hematite is even more erosive than barite.

Fig. 1.6 *(Reproduced with permission from Conoco Canada Limited.)*

At the aforementioned well in North Africa, a suction hose in the pump station forced a premature stoppage of a kill operation using 20 ppg mud weighted with barite and hematite. The well was dead when the hose failed. However, there was insufficient hydrostatic to control the bottom-hole pressure, and the well kicked off. Within minutes after the kill mud reached the surface, the side of the wellhead cut out.

Since erosion is a function of velocity, it should occur first at the perimeter of the well control system. Usually, turns in the flow path are the first to cut out. Anywhere the flow turns is a candidate for erosion. In blowout situations, it is prudent to begin monitoring wall thickness at all turns at the wellhead and downstream from the wellhead. Thickness testers are readily available to the industry and make the job very simple.

The worst case I ever saw in 50 years was in Bangladesh. All the waters of the Himalayas run through Bangladesh. As a result, the surface formations are simply a big sandbox composed mostly of very sharp quartz crystals. Within minutes after the well blew out, everything at the surface was leaking. Within days, the entire 10,000 psi BOP stack had been cut out or cut off. It was even cutting the drill pipe and casing in the hole into pieces and blowing the pieces into the air. A relief well was the only alternative.

Corrosion

Most processes of corrosion require so much time that they are not usually significant in well control operations. However, in well control operations, there are basically two corrosive elements that must be considered—hydrogen sulfide and carbon dioxide.

At the Lodge Pole blowout west of Edmonton, Alberta, Canada, in the mid-1980s, hydrogen sulfide played a disastrous role. The well blew out while on a trip. The decision was made to drop the drill pipe and close the blind rams. The hydrogen sulfide had caused the drill pipe to part not far beneath the rig floor. Consequently, when the pipe was cut, it didn't drop. Rather, it went out the derrick, and sparks ignited the well.

The effect of hydrogen sulfide on steel is documented by NACE. The NACE guidelines define the working limits of oil-field tubulars. These guidelines are very dependable. At a blowout in the southern part of the United States, hydrogen sulfide was a concern only if the surface temperature fell below 200°F. Throughout the project, the surface temperature was maintained above 200°F by adjusting the flow rate. No problems with the hydrogen sulfide were experienced.

Carbon dioxide corrosion takes place over a much longer period of time than hydrogen sulfide corrosion (and subsequent sulfide stress cracking), which is usually very sudden. The exposure time required for CO_2 to cause problems is generally so long that it is not a factor in normal well control operations, which last only a few weeks at the most. However, the potential for CO_2 corrosion cannot be ignored. The environment required for carbon dioxide corrosion is not as predictable as that required for H_2S.

The general requirement for CO_2 corrosion is based on the partial pressure. The partial pressure is the mole fraction multiplied by the total pressure. For most gases, the mole fraction is approximately equal to the volume fraction. If the partial pressure to CO_2 is greater than 30 psi, corrosion is certain. If the partial pressure to CO_2 is between 7 and 30 psi, corrosion is likely. If the partial pressure to CO_2 is less than 7 psi, corrosion is unlikely.

At the TXO Marshall, the presence of CO_2 complicated the original work. The well control work was similarly plagued. When the BOP was removed after the well was killed, the body was almost completely corroded and eroded away. One observer described its condition as resembling a spider web.

THREADED CONNECTIONS

I made a promise that I would address the issue of threaded connections in this book. So here it is. Threaded connections are okay—for sewer line connections, sprinkler systems, and household plumbing. But they have no place in the well control system. I have learned a lot of things from Bob Cudd over the last 35 years. One of the most important is this: in well control, Bob always advised to play only "aces, straights, and flushes." Threaded connections are none of these.

Sometime in the 1960s, I had the opportunity to investigate my first well control accident. A major company had a well control problem at a shallow well in the Oklahoma Panhandle. Two men were severely burned. One of them died. They were trying to kill the well by pumping into the annulus through a gate valve on a $2\frac{3}{8}$ in. double-extra-heavy nipple with 11 V threads. My recollection is that the nipple was rated to 5000 psi. Due to casting problems, the threads only made up about halfway. The fact was that the nipple failed at about 1500 psi.

The 11 V thread is not a good thread form. The "V" configuration allows stress concentrations at the base of the "V." In addition, the thread is tapered, which means that wall thickness is sacrificed to cut the thread.

If not completely buried, the connection will be weakest at the last engaged thread. When I made all the calculations for strength reduction due to the reduced wall thickness, water hammering, etc., they indicated that the strength of the 5000 psi working pressure nipple was reduced by the conditions to approximately 1500 psi—almost exactly where it failed.

At another job, a 10 V thread failed, and several people were killed. More recently, I investigated another accident where a threaded choke on the rig floor fill-up line failed and injured a man. It was the same scenario. The 11 V thread was not fully made up and failed at far below the rated working pressure (RWP). Fortunately, no one was killed.

API round threads are not much better. At a location on the edge of Perryton, Texas, the dual tree had 8 rd connections. We were lubricating a plug into the wellhead one Saturday morning. The plug is wedged in the tree above its intended setting location. The operator bled the lubricator. When he did, the plug came loose, and the impact severed the connection below the bottom master valve. That's as close as I ever came to being killed.

It is true that service companies routinely use threaded connections on high-pressure equipment used in stimulation work. The difference is that trained personnel handle the connections. Around the rig, untrained roughnecks and roustabouts do the work.

It is also true that in the past I have personally built many choke manifolds using ball valves and threaded connections downstream from the chokes. There were two reasons: One, I never allowed pressure downstream from the choke, and two, I was there to supervise the installation. There should never be pressure downstream from the choke in a choke manifold. After all, the separator is usually a 300 psi or less vessel. But strange things happen when people are excited. I watched a roughneck try to close a ball valve downstream from a choke during a kill operation. Had he done so, it probably would have killed him. Fortunately for everyone, a ball valve is almost impossible to close if there is significant flow.

THE STACK

Interestingly, the industry does not experience many failures within the BOP stack itself. There was one instance in Wyoming where a BOP failed because of a casting problem. In another case, the 5000 psi annular failed at 7800 psi. In general, the stack components are very good and very reliable.

A problem that is continually observed is that the equipment does not function when needed. At a well at Canadian, Texas, the annular preventer had been closed on a blowout, but the accumulator would not maintain pressure. Shursen and another guy were standing on the rig floor when the accumulator lost pressure and the annular preventer opened unexpectedly. The annular opened so quickly that the floor was engulfed in a fireball. Fortunately, no one was seriously burned. The source of the fire was never determined. The rig had been completely shut down, but the accumulator system should have been in working order.

At another blowout in Arkansas, nothing worked. The accumulator was not rigged up properly; the ancient annular would not work, and when the pipe rams were closed, the ram blocks fell off the transport arms. After that, the rams could not be opened. It's difficult to believe that this equipment was operated and tested as often as the reports indicated.

In another instance, the stack was to be tested prior to drilling the productive interval. The reports showed that the stack had been tested to the full working pressure of 5000 psi. After failing the test, it was found that the bolt holes had rusted out in the preventer!

These situations are not unique to one particular area of the world. Rather, they are common throughout the oil fields of the world. Operators should test and operate the components of the stack to be confident that they are functioning properly.

Having a remote accumulator away from any other part of the rig is a good idea. At one location, the accumulator was next to the mud pumps. The well pressured up and blew the vibrator hose between the mud pump and the stand pipe. The first thing that burned was the accumulator. A mud cross such as illustrated in Fig. 1.7 would have saved that rig. It would have been possible to vent the well through the panic line and pump through the kill line and kill the well.

This chapter pertains to all operations, whether they are offshore, onshore, remote, or in the middle of a city. Some peculiarities persist that require special considerations. For example, all the equipment in an offshore operation is confined to a small space. However, it is important to remember that a well is deep and dumb and does not know where it is or that there is some quantity of water below the rig floor. Therefore, when sacrifices are made and compromises are accepted due to self-imposed space limitations, serious consequences can result.

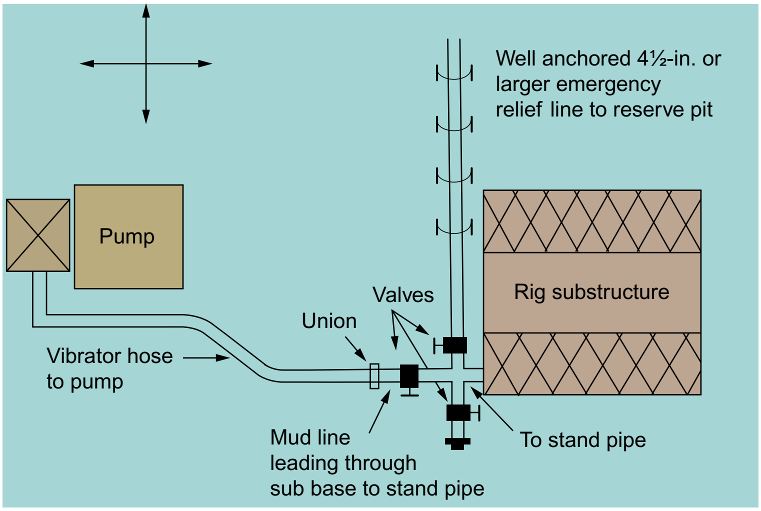


Fig. 1.7

THE CHOKE LINE

Many well control problems begin in the choke line or downstream of the choke line. It is unusual to find a rig without the potential for a serious problem between the BOP stack and the end of the flare lines. In order to appreciate how a choke line must be constructed, it is necessary to remember that, in a well control situation, solid-laden fluids are extremely abrasive.

A typical choke line is shown in Fig. 1.8. As illustrated, two valves are flanged to the drilling spool. There are outlets on the body of the BOPs. However, these outlets should not be used on a routine basis since severe body wear and erosion may result.

One valve is hydraulically operated, while the other is the backup or safety valve. The position of the hydraulic valve is important. Most often, it is outboard with a safety valve next to the spool to be used only if the hydraulic valve fails to operate properly. Many operators put the hydraulic valve inboard of the safety valve. Experience has shown that the short interval between the wellbore and the valve can become plugged with drill solids or barite during the normal course of drilling. Therefore, when a problem does occur, the manifold is inoperable due to plugging. The problem can be minimized and often eliminated by placing the hydraulic valve next to the casing spool.

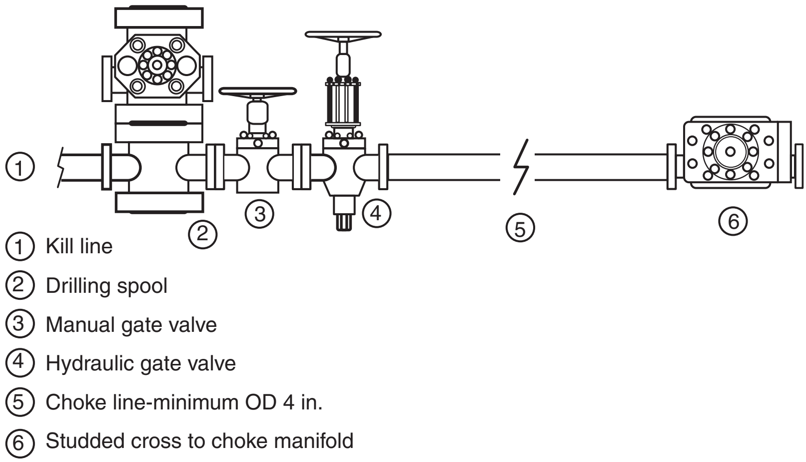


Fig. 1.8 Choke line.

The outboard position for the hydraulic valve is the better choice under most circumstances since the inboard valve is always the safety valve. If the hydraulic valve is outboard, it is important that the system be checked and flushed regularly to insure that the choke line is not obstructed with drill solids.

In areas where underbalanced drilling is routine, such as West Texas, drilling with gas influx is normal, and the wear on well control equipment can be a serious problem. In these areas, it is not uncommon to have more than one choke line to the manifold. The theory is sound. A backup choke line, in the event that the primary line washes out or is plugged, is an excellent approach.

A basic rule in well control is to have redundant systems where a failure in a single piece of equipment does not mean disaster for the operation. However, the second choke line must be as substantial and reliable as the primary choke line. In one instance, the secondary choke line was a 2 in. line from the braden head. The primary choke line failed, and the secondary line failed even faster. Since the secondary line was on the braden head with no BOP below, the well blew out under the substructure, caught fire, and burned the rig.

Therefore, the secondary choke line should come from the kill-line side or from a secondary drilling spool below an additional pipe ram. In addition, it must meet the same specifications for dimension and pressure as the primary choke line.

The choke line from the valves to the choke manifold is a constant problem. This line must be flanged, must have a minimum outside diameter of 4 in., and should be STRAIGHT between the stack and the manifold. Any bends, curves, or angles are very likely to erode. When that happens, well control becomes very difficult, lost, extremely hazardous, or all of the aforementioned. Just remember, STRAIGHT and no threaded connections.

If turns in the choke line are required, they should be made with T's and targets as illustrated in Fig. 1.9. The targets must be filled with babot and deep enough to withstand erosion. The direction of flow must be into the target.

Fig. 1.10 illustrates an improperly constructed choke line. Note that the choke line is bent slightly. In addition, the targets are backwards or with the flow to the well. The direction of the targets is a common point of misunderstanding throughout the worldwide industry. These points should be checked on all operations.

Continuous, straight steel lines are the preferred choke lines. Swivel joints should only be used in fracturing and cementing operations and should not be used in a choke line or any well control operation. At a deep, high-pressure sour well in southern Mississippi, a hammer union failed, and the rig burned.

Finally, the use of hoses has become more popular in recent years. Hoses are quick and convenient to install. However, hoses are recommended only

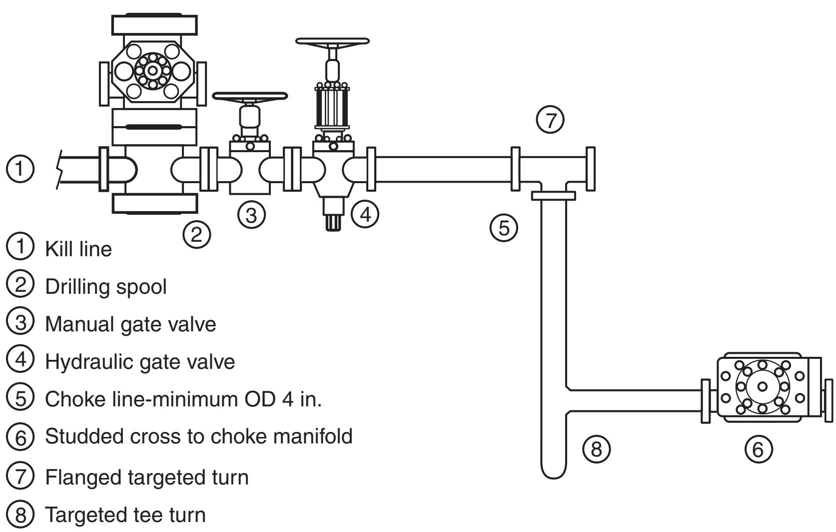


Fig. 1.9 Choke line with turns.

Fig. 1.10

in floating drilling operations that offer no alternative. Further, consider that, in the two most serious well control problems in the North Sea to date, hose failure was the root cause.

Hoses and swivel joints work well on many wells because serious well control problems do not occur on many wells. However, when serious well control problems do occur, solid equipment has better integrity. Swivel joints can be used on the pumping side in kill operations for short periods of time. As of this writing, hose use should be restricted to the suction side of the pumping equipment. Presently, hoses cannot be recommended to replace choke lines. Although the literature is compelling, it is illogical to conclude that rubber is harder than steel.

In summary, the choke line should be straight and no less than 4 in. in diameter. Hoses and threaded connections should not be used. Any turns should be targeted as illustrated. Finally, know this: if things get rough enough—that is, if there are lots of solids in the flow stream—there will be erosion everywhere the flow turns, including the drilling cross. The erosion will be on the outside of the turn immediately downstream.

THE CHOKE MANIFOLD

The Valves

The minimum requirement for a choke manifold is presented in Fig. 1.11. I have seen some real pieces of garbage rigged up as choke manifolds. One such choke manifold is illustrated in Fig. 1.12. It would be better, in most instances, to have only a panic line and no choke manifold than to have one like that shown in Fig. 1.12.

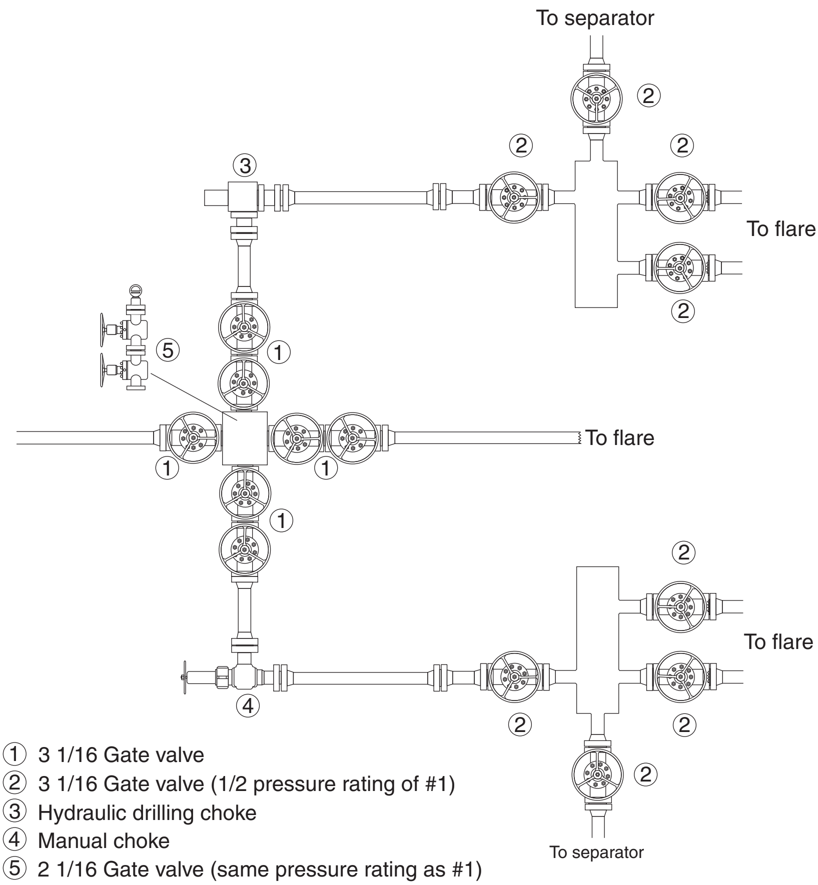


Fig. 1.11 The choke manifold.

Fig. 1.12

With a manifold such as that shown in Fig. 1.11, the outboard valves are routinely used, and the inboard valves are reserved for an unexpected emergency or when the outboard valve simply fails to seal. In general, gate valves can endure considerable wear and tear and still function with sufficient seal to permit the installation of another valve, if necessary. Gate valves are designed to be open or closed. They are not intended to be used to merely restrict flow. That is the function of the choke. When used to restrict flow, the body of the valve is likely to cut out. Gate valves are often closed on flow. Absent unusually large volumes of sand or other abrasives in the flow, the valve will close and seal on almost any volume at any pressure.

I have rigged up many choke manifolds with gate valves upstream from the chokes and ball valves downstream from the chokes. I used these manifolds in rough conditions, and they worked without problems or failures. However, a ball valve cannot be closed on any significant flow. For that reason alone, I no longer build manifolds using ball valves.

The general standard in the industry is for the valves downstream from the chokes to have a pressure rating of at least one-half that of the valves upstream from the chokes. For example, by industry custom, a 10,000 psi choke manifold will have 10,000 psi working pressure valves upstream from the chokes and 5000 psi working pressure valves downstream from the chokes. That was not always the standard, and I have never been able to determine any justification for that practice.

Downstream from the chokes, the pressure can never be more than a few hundred psi. The pressure is atmospheric in the mud pits, downstream from the separator, and at the end of the flare lines. The working pressure of the separator is never more than a couple hundred psi. Therefore, how could the pressure anywhere beyond the chokes ever reach 5000 psi? The answer is that it cannot. The choice of 5000 psi working pressure downstream from the chokes of a 10,000 psi manifold is arbitrary.

It is necessary for the plumbing downstream from the chokes to be substantial with respect to the wall thickness. Remember, as the velocity increases, the tendency to erode also increases dramatically. Therefore, the most likely place for erosion is downstream from the choke. Everything downstream from the choke should be consistent with internal diameter. Any changes in internal diameter will increase the potential for erosion.

As the well becomes more complex and the probability of well control problems increases, redundancy in the manifold becomes a necessity. The manifold shown in Fig. 1.13 was recently rigged up on a well control

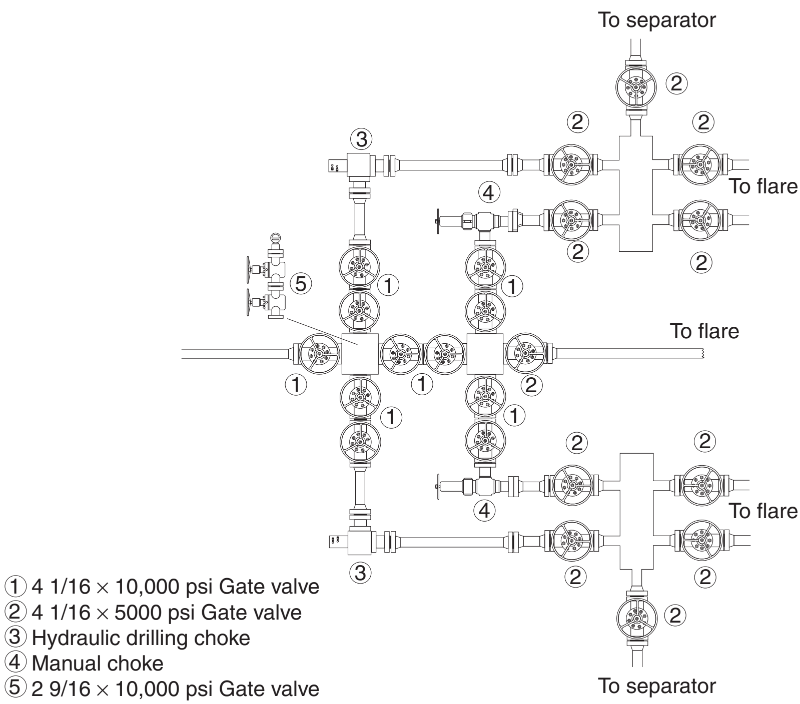


Fig. 1.13 $4-\frac{1}{16}$ by 10,000 psi choke manifold.

problem in the South Texas Gulf Coast. As illustrated in Fig. 1.13, there were positions for four chokes on the manifold. Options were good. Either side of the manifold could be the primary side. Since each side was separately manifolded to individual separators, there was a redundancy for every system in the manifold. Failure of any single component of the manifold would not jeopardize the operation.

The Drilling Choke

Outboard of the gate valves are the drilling chokes. The drilling choke is the heart of the well control system. Well control was not routinely possible prior to the advent of the modern drilling choke. Positive chokes and production chokes were not designed for well control operations and are not tough enough. Production chokes and positive chokes should not be included in the choke manifold unless there is a specific production-well testing requirement. Under well control conditions, the best production choke can cut out in a few minutes. If the manifold is spaced for a production choke, a welder will be required to install an additional drilling choke if it is needed. Obviously, it is not a good practice to weld on a manifold when well control operations are in progress. If a production choke is used in a manifold system, it is recommended that the system be spaced so that an additional drilling choke can readily fit. Even with this precaution, there remains the problem of testing newly installed equipment with the well control operation in progress.

In the late 1950s, a company known as drilling well control began controlling kicks with a series of skid-mounted separators. Prior to this technology, it was not possible to hold pressure on the annulus to control the well. It was awkward at best with the separators. The system was normally composed of two to three separators, depending on the anticipated annulus pressures. The annulus pressure was stepped down through the separators in an effort to maintain a specific annular pressure. It represented a significant step forward in technology but pointed to the need for a drilling choke that could withstand the erosion resulting from solid-laden multiphase flow.

The first effort was affectionately known as the "horse's ass" choke. The nickname will be apparent as its working mechanism is understood. The choke is illustrated in Fig. 1.14. Basically, it was an annular BOP turned on its side. The flow stream entered the rubber bladder. The pressure on the well was maintained by pressuring the back side of the bladder. The solids would cut out the bladder, requiring that the operator pays close

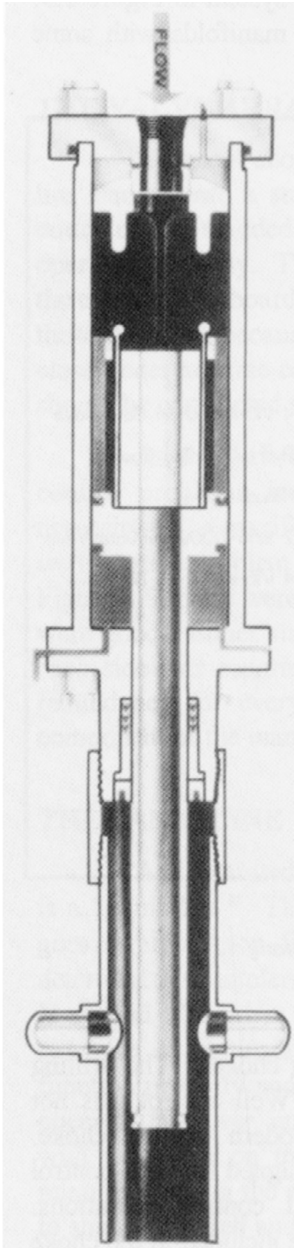


Fig. 1.14

attention to the pressures everywhere at the same time, making it an awkward choke to use.

All modern drilling chokes fall into two categories according to the manner in which choking is achieved. In the first category, choking is achieved by rotating two surfaces with matching openings. Some use flat plates, and others use cylinders or cages. The SWACO Super Choke shown in Fig. 1.15 is typical of this category. Within the flow path of the SWACO Super Choke, there are two polished tungsten carbide plates. Both have half-moon-shaped openings. One plate is fixed, and the other is hydraulically rotated. As one half-moon opening rotates over the opening in the fixed plate, flow is permitted. Choking is accomplished by reducing the size of the matched openings.

The other category is typified by the Cameron drilling choke shown in Fig. 1.16. In this category, a tungsten carbide bean is hydraulically inserted into a tungsten carbide sleeve. The action is very similar to the typical production choke. The degree of choking is a function of the depth of the cylinder into the sleeve.

It is important to fully understand the operating system of the choke being used. Can it be operated without rig power? Can it be tested to full working pressure? Is there more than one operating station? If the hydraulic system in the operating station is connected to the choke by long hoses, is the

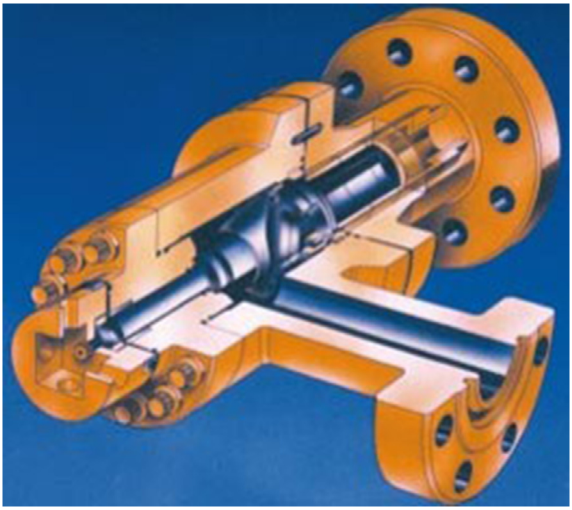


Fig. 1.15

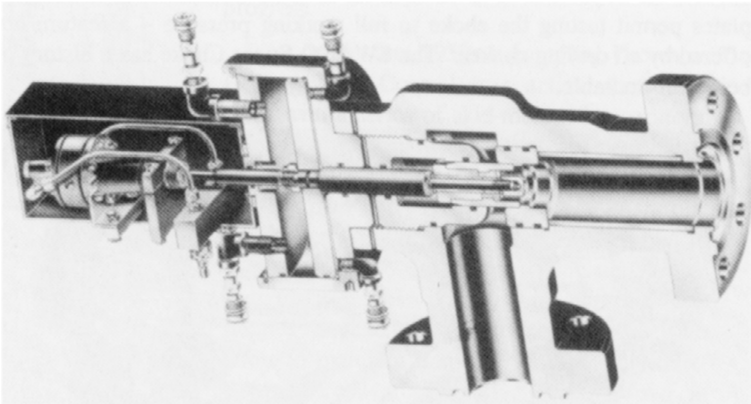


Fig. 1.16

choke compromised? Is it difficult and/or time-consuming to replace the choking mechanism?

Whichever choke one decides to use, most modern drilling chokes are very reliable.

The Panic Line

As illustrated in Fig. 1.13, in the center of most land manifolds is a "panic line." This line is usually 4 in. or larger in diameter and goes straight to a flare pit. The idea is that, if the well condition deteriorates to intolerable conditions, the well can be vented to the pit. It is a good idea when properly used and a bad idea when misused. For example, in one instance, the rig crew could not get the drilling choke to function properly, and in an effort to relieve the well, the panic line was opened. However, an effort was made to hold back pressure on the well with the valve on the panic line. The valve cut out in less than 30 min, making the entire manifold inoperable. There was no choice but to shut in the well and let it blow out underground until the manifold could be repaired.

Valves are made to be opened or closed. Chokes are designed to restrict flow. If the panic line is to be used, the line must be fully opened to the flare pit.

The Header

In the typical oil-field choke manifold, the flow lines leaving the chokes are manifolded together at the "header." The idea is that from the "header" the flow can be directed from one or both chokes to the separator or to the flare pit.

Some headers are substantially constructed and are heavier than cannon barrels. However, most oil-field headers are constructed from a discarded piece of casing. In general, most headers defeat the purpose and effectiveness of the well control system. In my opinion, the header is the heart of many problems and should be eliminated.

Consider Figs. 1.17 and 1.18, which illustrate a header design common to many operations. This system failed for two reasons. The lines between the choke manifold and the header were 2 in. outside diameter, which resulted in excessive velocities, and the back side of the header was eroded away by the jetting action of the flow stream as it entered the header and expanded. Obviously, the well was out of control and had to be either vented or shut in to blow out underground, depending on the surface pressure and casing design. In most instances, the well is shut in, and an underground blowout is the result.

If the "panic line" is also manifolded into the header, which is often the case, almost anything else that can happen is destined to be disastrous. Usually, the header is near the rig. If there is a failure, continuing to flow the well is obviously dangerous. If the flow is at the header, there is eminent danger of fire and total loss of the rig. If the decision is made to shut in and not flow the

Fig. 1.17

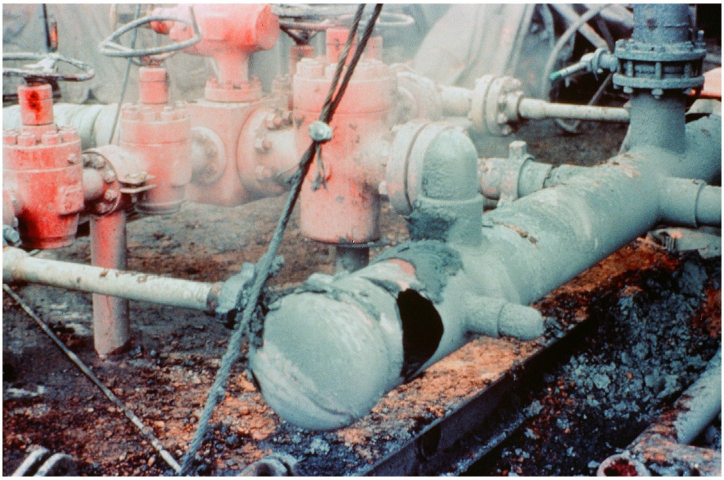


Fig. 1.18

well, the casing could be ruptured or an underground blowout could ensue. There is no good reason to have the header when all the options can be maintained with alternative plumbing. Two manifolds without a common header are shown in Figs. 1.11 and 1.13.

Many equipment failures in well control operations occur between the choke and the separator. With regard to the lines immediately downstream from the chokes, the most common problem is erosion resulting from insufficient size. They should be at least 4 in. in diameter in order to minimize the velocity. Any abrupt change in the diameter will cause an area of more severe erosion. These lines do not have to be high pressured; however, they should have a yield strength of 80,000 psi or greater in order that the steel will be harder than most of the particulate in the flow stream and resist erosion. Two-inch lines are too small for any operation and should not be used.

THE SEPARATOR

When well control operations are required, redundancy is a criterion for all components of the well control system. In most operations, there is no redundancy in the components downstream from the chokes, and if a failure occurs, the operation is in serious jeopardy. Therefore, the integrity of the components lacking redundancy is important and demands critical attention.

The lines connecting to the separator are often problematic. The fluid velocity downstream from the choke is higher. The drilling fluid, gas, barite, and drill solids at high velocities combine to produce a very effective cutter. Under severe conditions, sweeping turns can and will cut out in a matter of a few minutes. Even very slight bends, which are barely noticeable, have been known to erode completely in a few minutes.

These lines connecting the chokes to the separator must be as straight as possible. Where straight lines are not possible, targeted turns are mandatory. A connection such as that shown in Fig. 1.19, which was being used in a deep, high-pressure offshore operation, will erode in a few minutes under severe service. Hoses and swivel joints such as chicksans are not recommended.

The connecting lines should have an outside diameter equal to or greater than 4 in. In the prolific Tuscaloosa trend, the outside diameter of the line from the header to the separator is routinely 8 in. Even an 8 in. line must utilize targeted turns if turns are required. At one operation, a sweep turn in the 8 in. line from the manifold to the separator was completely washed out in only a few hours.

The separator routinely is a source of problems. The separator problems most frequently encountered are due to size, inability to adequately control the liquid level, and erosion of the body. The separator should be sized to adequately accommodate the anticipated gas volumes. The volume of gas the separator will accommodate is a function of the physical size of the vessel, maximum separator working pressure, and flare line size.

Fig. 1.19

More often, the separator is too small and poorly designed. In offshore operations, space is always limited, and the separator is easily neglected. As illustrated in Fig. 1.20, a typical offshore separator is small, improperly plumbed, and inaccessible. In land operations, where well control problems are rarely encountered, the vessels represented to be separators are commonly a bad joke, as is the manifold system as a whole, which is often incapable of performing as intended. A typical example is shown in Fig. 1.21. These "separators" were simply constructed from a discarded piece of casing or drive pipe. In most of these cases, it would be better if there were no separator or manifold system, and the only alternative available to the crew was to shut in the well and wait for professionals.

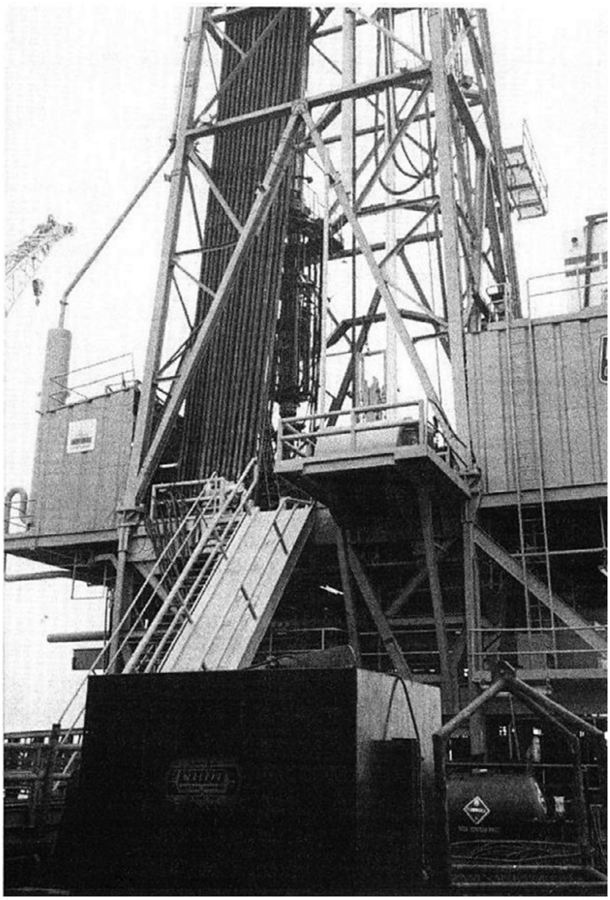


Fig. 1.20

Fig. 1.21

All separators intended for use in well control operations should be BIG! No vessel should be smaller than 4 ft in diameter and 8 ft in height. Separators used in operations where production is prolific, such as the Tuscaloosa trend, may be as large as 6 ft in diameter and 25 ft in length.

Separator size is also expressed as a function of the operating pressure of the vessel and the volume of gas and fluid the system can accommodate. Generally, the operating pressure of the vessel is approximately 125 psi. However, the operating pressure of the system may be limited by the liquid level control mechanism. A positive liquid level control is recommended and, if utilized, will make the system much more reliable.

However, it is often the case that the liquid level in the separator is simply controlled by a hydrostatic column of mud. Sometimes, the separator vessel is simply immersed a few feet into the mud pit. In other cases, a hydrostatic riser controls the liquid level. Therefore, when the pressure in the vessel exceeds the hydrostatic pressure of the column controlling the liquid level, gas and reservoir fluids will pass out the bottom of the separator and into the mud pits. Such a scenario is common with separators designed as described, and the results are unacceptably hazardous.

Consider the separator pictured in Fig. 1.20. The liquid level in the separator is controlled by the hydrostatic loop in the left center of the figure. This loop is approximately 3 ft in length. Therefore, when the pressure in the vessel exceeds a maximum 3 psi, gas in the separator will pass directly to the mud room. In this case, the mud room had minimal ventilation. Any serious well control operation would not be possible with this arrangement.

The size and length of the flare line from the separator to the flare pit are important components of the system. The larger the flare line, the better. The flare line must be straight and not less than 6 in. in diameter. In the prolific Tuscaloosa trend, 12 in. flare lines are common. The flare line should be no less than 100 yd in length, and the flare pit should not be adjacent to any roads or buildings. In one instance, the flare line terminated no more than 30 yd from the rig floor. A flare of any size would make access to the rig floor impossible. In another instance, the flare pit was adjacent to the only access road. When the well blew out, a new road had to be constructed before well control operations could be commenced.

Finally, fluid entry into the vessel is important. Some separators are designed to permit tangential entry. That is, the fluid enters tangential to the wall of the vessel. If the fluid is only gas and liquid, the design is satisfactory. However, if the fluid contains any solids, the vessel will erode rapidly. A perpendicular entry is the best. An acceptable separator design is illustrated in Fig. 1.22.

In my opinion, the separator system design contributed to one of the worst disasters of modern times. The separator had no positive liquid level control. It simply had a liquid leg, and to prevent the separator from siphoning, it had a vacuum breaker in the line. Both the vacuum breaker and the vent line had "U's" at the end to prevent rain from contaminating the mud system. When the well blew out, it blew the separator dry and sent hydrocarbons into the mud room. The "U's" at the end of the vent line and vacuum break directed the flow back toward the rig floor. The entire rig became saturated with hydrocarbons and caught fire within minutes. Had there been a positive liquid level control and a straight vent line, I believe the outcome would have been different.

THE KILL LINE

The purpose of the kill line (see Fig. 1.23) is to provide remote hydraulic access to the well. Usually, the kill line extends approximately 100–150 ft from the wellhead. Some operators have a valve at the end of the kill line.

The kill-line access to the bore hole should never be used for any purpose other than that intended—emergency access. The line from the kill-line

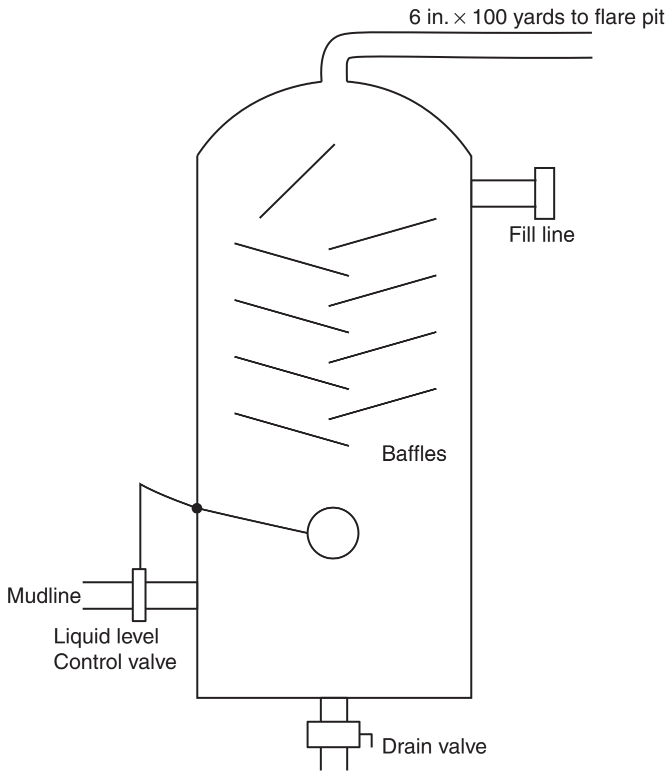


Fig. 1.22 Separator.

check valve to the outer access should be straight. The valve at the end of the kill line is optional.

The kill-line access should never be used as a fill-up line. At one location, a fill-up line had been connected to the kill-line access. When a kick was taken and the well was shut in, the subsequent pressure ruptured the fill-up line. The flow was ignited, and the rig was lost. At many locations, the kill line has provided the intended access to the wellbore, and the well has been saved. The integrity of the kill-line system can be assured by using the kill line only as intended.

THE STABBING VALVE

On all rigs and work-over operations there should be a valve readily accessible on the rig floor, which is adapted to the tubulars. Such a valve is routinely called a "stabbing valve" or full opening safety valve. In the event of a

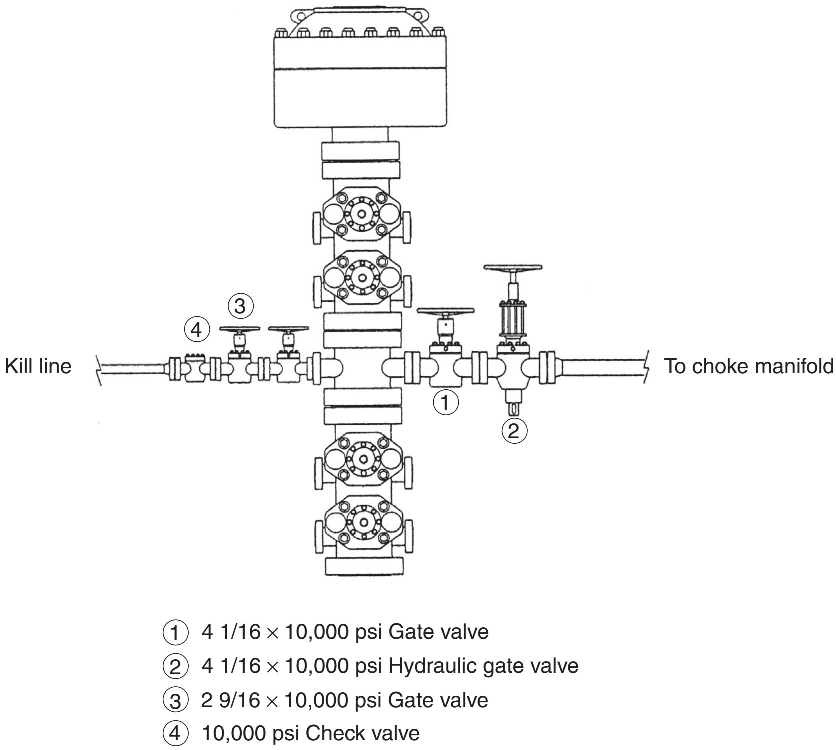


Fig. 1.23 10,000 psi kill line.

kick during a trip, the stabbing valve is installed in the connection on the rig floor and closed to prevent flow through the drill string. Ordinarily, the stabbing valve is a ball valve, as illustrated in Fig. 1.24. The valve should be immediately available on the rig floor and in the open position. Crossovers to any drill pipe, HWDP, and collars with different threaded connections should also be immediately available on the rig floor. The handle to the valve should be stored where it can be easily found, and all rig crew knows where to find the handle. The valve will not perform its function if the rig crew cannot find the handle to close the valve.

The ball valve is probably the best alternative available under most circumstances. However, the valve is extremely difficult and problematic to operate under pressure. If the valve is closed and pressure is permitted to build under it, it becomes impossible to open the valve without equalizing the pressure. If the pressure below the valve is unknown, the pressure above

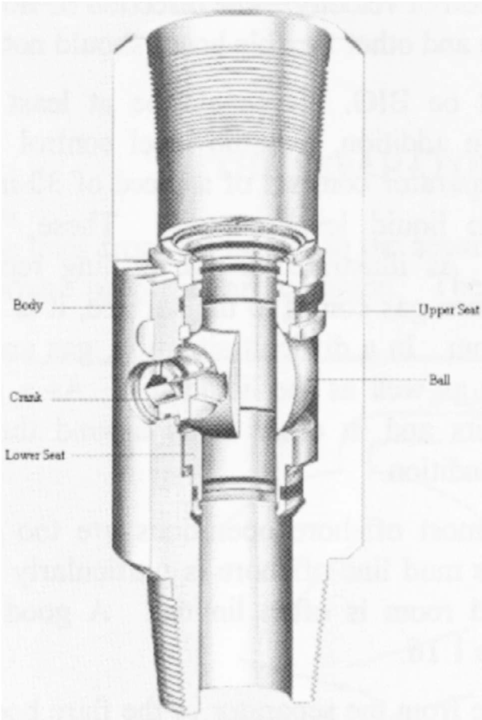


Fig. 1.24 TIW valve.

the valve must be increased in small increments in order to equalize and open the valve.

The ball in the stabbing valve must have an internal diameter equal to or greater than the tubulars below the valve, and the internal diameter of the valve must be documented. Too often, the internal diameter is too small, unknown, and undocumented. Therefore, when a well control problem does occur, the first operation is to freeze the stabbing valve and replace it with a valve suitable for the job.

If the flow through the drill string is significant, it may not be possible to close the stabbing valve. In many instances, when a flow is observed, the BOPs are closed before the stabbing valve. With all of the flow through the drill string, it may not be possible to close the stabbing valve. In that instance, it is necessary to open the BOPs, attempt to close the stabbing valve, and reclose the BOPs. This discussion emphasizes the accessibility of the stabbing valve and the necessity of conducting drills to ensure that the stabbing valve can be readily installed and operated.

Finally, when the stabbing valve cannot be installed or closed and shear rams have been included in the stack, there is a tendency to activate the shear rams and sever the drill string. This option should be considered carefully. In most instances, shearing the drill string will result in the loss of the well. The energy released in a deep well, when the drill string is suddenly severed at the surface, is unimaginable and can be several times that required to cause the drill string to destroy itself along with the casing in the well. When that happens, chances for control from the surface are significantly reduced.

THE ESCAPE SYSTEM

On more than one occasion, the improper installation of the escape system resulted in the death of the man working in the derrick. In one instance, the system was attached to the derrick leg at the same level as the work platform. When the well blew out and caught fire, the derrick hand could not get to the escape line because of the fire.

The escape line must be anchored to the derrick above the work platform so that the derrick man can exit the rear of the work platform. There must be a door at the rear of the work platform. Wind walls and all else must be designed such that the exit is unobstructed.

BARRIERS

A well barrier is a barrier that prevents flow from a formation that is a potential source of flow. Well barriers can be divided into three categories:

- Primary barrier
- Secondary barrier
- Permanent barrier

The primary well barrier is the first barrier that will prevent flow into the wellbore. The secondary well barrier is a barrier that can be activated to prevent flow into the wellbore if the primary barrier fails. This is easily demonstrated in an overbalanced drilling operation. The primary well barrier is the drilling fluid. As long as the hydrostatic pressure of the drilling fluid (density) is more than the formation pressure, the well will not flow. The secondary barrier is the BOP. If the primary barrier fails (hydrostatic of the drilling fluid is not sufficient), the secondary barrier is activated. Operations do not continue until the primary barrier is restored.

A permanent barrier is a well barrier that permanently seals a source of inflow. An example would be in a plug and abandonment operation. If a cast-iron bridge plug is set above perforations in order to permanently abandon the zone, then it becomes a permanent barrier. Many times, cement is set on top of the bridge plug. Regulatory bodies may require pressure testing of the permanent barrier or tagging the cement with the pipe.

Well Barrier Envelope

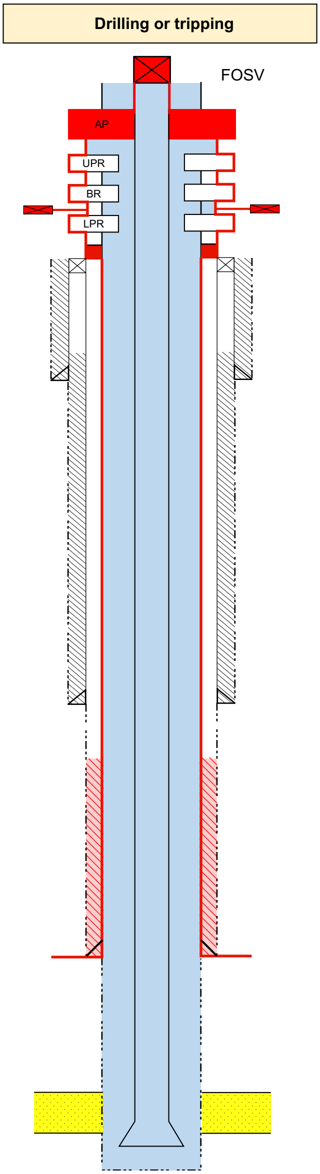
A well barrier element (WBE), such as the BOP, is seldom capable of containing the well by itself. It is dependent upon other well barrier elements. Other parts of the wellbore must also have integrity and are considered additional well barrier elements. Together, all the well barrier elements control the well and are usually called the well barrier envelope. A well barrier envelope is one or more WBEs that prevents fluids or gases from flowing unintentionally from a formation, into another formation or to the surface.

There are many well barrier elements in the industry. They include but not limited to the following:

- Fluid columns
- Blowout preventers for drilling, workover, coiled tubing, and wire line
- *In situ* formation fracture gradient
- Packers and bridge plugs
- Cement plugs
- Tubing plugs
- Casing and cement
- Full opening safety valve
- Inside BOP
- Tubing and drill strings
- Wellhead and tree
- Subsurface safety valves

Given the drilling or tripping example in Fig. 1.25, the fluid column is the primary barrier. Even though it is common to think of the fluid column as acting as a lone barrier, the wellbore still has to have integrity in the casing, cement, and open hole. If lost circulation occurs, the fluid column might not have enough hydrostatic to keep the well from flowing.

The secondary barrier would be the BOP, but it also does not act alone. In this case, the annular is closed to stop the flow. The rest of the wellbore has to have enough integrity to keep the well from flowing with surface pressure applied. As can be seen in Fig. 1.25 (*red*), the well barrier elements are drilling BOP, wellhead, casing, cement, drill pipe, full opening safety valve, and *in situ* formation. All of the individual well barrier elements act



Well barrier elements	Comments
Primary well barrier	
1. Fluid column	
Secondary well barrier	
1. Casing cement	
2. Casing	Last casing set
3. Wellhead	
4. Drilling BOP	
5. Drill string	Drill pipe
6. Full opening safety valve	Stabbed or top drive
7. In-situ formation	

Fig. 1.25 Well barrier schematic for drilling and tripping [1]. *AP*, annular preventer; *UPR*, upper pipe ram; *BR*, blind ram; *LPR*, lower pipe ram; *FOSV*, full opening safety valve.

together as the well barrier envelope and must be able to hold the additional pressure.

Fig. 1.26 shows a case for drilling and tripping with a subsea BOP and a shearable drill string. The fluid column is the primary barrier, and the BOP and other wellbore envelope components are the secondary barrier. If a nonshearable drill string is used, the pipe rams or annular would be closed, and the upper drill string and FOSV become part of the secondary barrier as in Fig. 1.27.

Two Barrier Policy

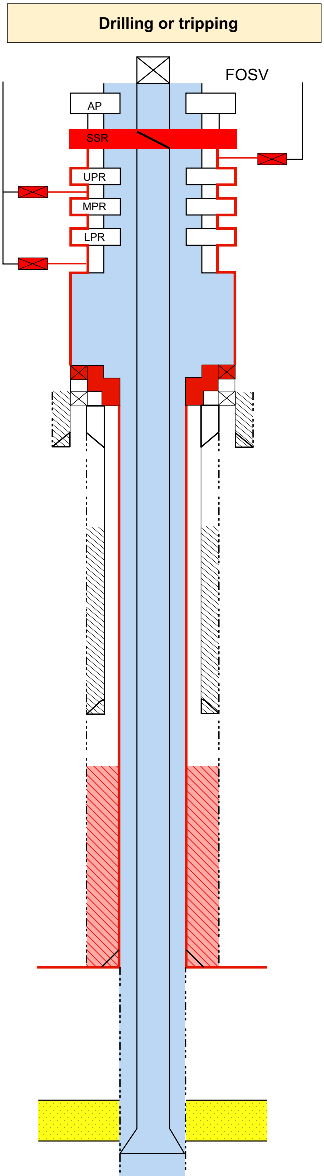
Most of the industry operates on a two-barrier policy whenever possible. There is a primary barrier and secondary barrier. The primary barrier keeps the well under control. If the primary barrier is lost, the secondary barrier is activated in order to contain the well. However, a barrier is not really a barrier until tested, whenever possible.

Blowout prevention equipment needs to be tested before it is used. Many components of the BOP can be tested on the stump prior to nippling up. Then, the high-pressure connections to the choke/kill lines and wellhead can be tested when nippled up. According to the API [2], all components should be tested to a low pressure between 250 and 350 psi and then to the high pressure for a minimum of 5 min with no visible indication of a leak.

The high-pressure test will be a function of the RWP of the equipment including the wellhead and valves. If the rig has a 10,000 psi BOP stack but the maximum anticipated surface pressure (MASP) is less than 5000 psi, then it is acceptable to test the equipment to 5000 psi. If the BOP stack is 10,000 psi but the wellhead is 5000 psi, then the stack can only be tested to 5000 psi, which is the lowest RWP of the components in the blowout prevention equipment. Table 1.1 is a copy of Table 2 from the API STD 53 for testing surface BOPs.

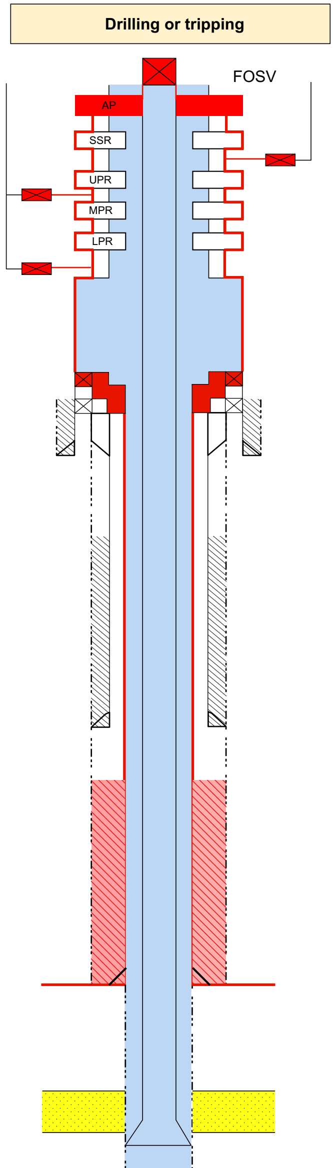
The well control equipment requires testing at least every 21 days after the initial nipple up. (Note: Some government agencies may require more frequent testing.) On subsequent tests, the BOPs can be tested to the MASP of the hole section as indicated in Table 3 of the API STD 53. If any pressure containing connection is broken apart, then that connection needs to be retested as soon as possible.

BOP equipment and fluid columns are relatively easy to understand. Other downhole tools can also be a barrier such as packers or bridge plugs.



Well barrier elements	Comments
Primary well barrier	
1. Fluid column	
Secondary well barrier	
1. Casing cement	
2. Casing	Last casing set
3. Wellhead	
4. Drilling BOP	Shear seal rams
5. In-situ formation	Drill pipe

Fig. 1.26 Well barrier schematic for subsea drilling and tripping [1]. *AP*, annular preventer; *SSR*, sheer seal rams; *UPR*, upper pipe ram; *MPR*, middle pipe ram; *LPR*, lower pipe ram; *FOSV*, full opening safety valve.



Well barrier elements	Comments
Primary well barrier	
1. Fluid column	
Secondary well barrier	
1. Casing cement	
2. Casing	Last casing set
3. Wellhead	
4. Drilling BOP	Shear seal rams
7. In-situ formation	Drill pipe

Fig. 1.27 Drilling and tripping with nonshearable drill string. *AP*, annular preventer; *SSR*, sheer seal rams; *UPR*, upper pipe ram; *MPR*, middle pipe ram; *LPR*, lower pipe ram; *FOSV*, full opening safety valve.

Table 1.1 Pressure test, surface BOP systems, and initial test

Component to be tested	Pressure test—low pressure[a] psi (MPa)	Pressure test—high pressure[b,c] psi (MPa)
Annular preventer	250–350 (1.72–2.41)	Lesser of 70% of annular RWP, RWP of wellhead, or ram preventer test pressure
Operating chambers	N/A	Maximum operating pressure recommended by the annular BOP manufacturer
Ram preventer		
Fixed pipe Variable bore Blind/blind shear	250–350 (1.72–2.41)	RWP of ram BOPs or RWP of the wellhead system, whichever is lower
Operating chamber	N/A	Maximum operating pressure recommended by the annular BOP manufacturer
Choke and kill lines and valves	250–350 (1.72–2.41)	RWP of ram BOPs or RWP of the wellhead system, whichever is lower
Operating chamber	N/A	Maximum operating pressure recommended by the valve manufacturer
Choke manifold		
Upstream of choke(s)	250–350 (1.72–2.41)	RWP of ram BOPs, RWP of the wellhead system, or RWP choke(s) inlet, whichever is lower
Downstream of choke(s)		RWP of choke(s) outlet, valve(s), or line(s), whichever is lower
Adjustable chokes	Function test only; verification of backup system	
BOP control system		
Manifold and BOP lines	N/A	Control system maximum operating pressure
Accumulator pressure	Verify precharge	N/A
Close time Pump capability Control stations	Function test	N/A

Table 1.1 Pressure test, surface BOP systems, and initial test—cont'd

Component to be tested	Pressure test—low pressure psi (MPa)	Pressure test—high pressure' psi (MPa)
Safety valves		
Kelly, kelly valves, and safety valves	250–350 (1.72–2.41)	RWP of components
Auxiliary equipment		
Poor boy degasser/ MGS[d]	In accordance with equipment owner's PM program	Flow test
Trip tank, flo-show, etc.	Visual and manual verification	Flow test

[a]The low-pressure test shall be stabilized for at least 5 min with no visible leaks. Flow-type test shall be of sufficient duration to observe for significant leaks.
[b]The high-pressure test shall be stabilized for at least 5 min with no visible leaks.
[c]Well control equipment may have a higher rated working pressure than required for the well site. The site-specific test requirements shall be used for these situations.
[d]The MGS requires a one-time hydrostatic test during manufacturing or upon installation. Subsequent welding on the MGS vessel shall require an additional hydrostatic test to be performed.

However, they still need to be tested to be a barrier. Liner tops are also barriers after they have been tested. However, a barrier should be tested in the direction of flow whenever possible. Therefore, a liner top or bridge plug requires a negative pressure test. Not all formations have enough pressure to do a negative pressure test. If the formation pressure is less than the hydrostatic of fresh water, then nitrogen would have to be injected into the fluid column in order to do a negative pressure test. The nitrogen would complicate the test and make it very difficult to interpret. If the formation pressure does not allow a negative pressure test with a column of water, then conducting a positive pressure test in the opposite direction of flow is acceptable as long as the barrier is designed to stop the flow in both directions.

Cement can be a well barrier. Initially, it is a hydrostatic barrier similar to the drilling fluid. But, as cement sets, it can lose hydrostatic pressure. Annular gas flows can occur after the cement has been placed but before the cement develops enough compressive strength to prevent flow. Temporary barriers, such as a BOP stack, should not be removed until the cement has developed 50 psi compressive strength. The 50 psi compressive strength threshold exceeds the minimum static gel strength value needed to prevent fluid influx [3].

As an example, consider running a long string of casing on a land operation. After drilling to the desired depth, casing is run. The BOP has to have the capability of sealing on the casing either with the annular (provided the pressure rating is sufficient for the MASP), variable bore rams or casing rams. If casing rams are placed in the BOP, the casing rams will have to be tested to MASP. If variable bore rams are used, the variable bore rams should be tested on the same size pipe as the casing when the BOP is nippled up. API STD 53 says that, "[f]or the initial BOP test (upon installation), the annular(s) and variable bore ram(s) (VBR) shall be pressure tested on the largest and smallest OD drill pipe to be used in well program [4]." Many times, the drill pipe may be 5½ in., and the production casing is 5½ in. If the casing is larger, the variable bore rams will have to be tested on pipe equivalent to the casing size before running casing.

It must be possible to shut in the casing if a kick occurs. Float equipment might keep the well from flowing up the casing, but the float equipment is rarely tested from the bottom. Auto-fill equipment may not have been converted. Therefore, there should be a crossover and valve (secondary barrier) on the rig floor that can be installed immediately if the well starts flowing up the casing. The crossover and valve serve the same function as the FOSV in drilling operations.

Once the casing gets to bottom, it can be cemented. The cementing head becomes part of the secondary barrier when installed on the casing. If the floats do not hold, the cement head and valves will be used to shut in the well while the cement sets.

The cement is generally heavier than the drilling fluid, but may not be when the pore pressures and fracture gradients are close to each other. After the plug has been bumped, the pressure is bled off the casing to make sure the floats are holding. The volume of fluid bled back, and the flow has to be monitored to make sure the float equipment is holding. If the floats do not hold, the valve on the cement head has to be shut in until the cement sets. A minimum of 50 psi compressive strength is required for the WOC time. If the cement and displacement fluid density are similar, the well may not flow even if the floats are not holding.

The next decision is when to nipple down the BOP to install slips and/or another section of the wellhead. (Note: Not all wellheads require nippling down the BOP to install hangers and seals.) WOC time before nippling down the BOP should be long enough to allow the cement to gain 50 psi compressive strength.

When the BOP is nippled down, there is only a fluid barrier in the annulus in most cases. The two-barrier system is not being used if the BOPs are lifted up to install slips and cut off the casing. Any plan for removing the BOP barrier should take into consideration that the secondary barrier is no longer active. The plan should mitigate the risk. For example, it may be advisable to monitor any potential flow from the annulus on the trip tank for 30 min before unbolting the BOP. Any number of wells have blown out, while the BOPs were lifted up to install casing slips and cut off the casing.

Under normal operations, the two-barrier system includes the fluid column as the primary barrier and the BOP equipment as the secondary barrier. If the fluid barrier is lost, drilling operations should not continue until the primary barrier has been restored. Other operations such as running casing, cementing, and testing liner tops need to be carefully thought out as to what are the primary and secondary barriers including all the components of the wellbore envelope. If an operation cannot be continued while maintaining two barriers, a risk assessment should be conducted to determine the risks and how to mitigate the risks.

APPLICATION OF MPD EQUIPMENT

Managed pressure drilling (MPD) is defined as "an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole-pressure-environment limits and to manage the annular hydraulic pressure profile accordingly. The intention of MPD is to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process [5]." In other words, MPD is not underbalanced drilling. The objective is to prevent any influx or kick. One application of MPD is to drill wells where the window between pore pressure and fracture gradient is narrow and a kick is more likely to occur. Because of the narrow window, the influx volume must be limited so kick detection is important. Additionally, annular pressures have to be managed in order to keep from exceeding the fracture gradient. MPD equipment and computer programs have been developed to limit kick volume and manage equivalent circulating density and surface pressure more precisely. That same equipment can be used to help detect and manage kicks in conventional wells.

Flow Meters

One piece of equipment used to detect kicks earlier is a more precise flow meter. The flow-line paddle meter has been around for many years, but it only gives a relative flow volume. Smaller increases in flow are harder to detect so flow meters that measure actual flow rate and density have been developed. The most common one is the Coriolis meter and is based on the principles of motion mechanics. When the drilling fluid enters the meter, it is split between two flow tubes as shown in Fig. 1.28. During operation, a drive coil stimulates the tubes to oscillate in opposition at the natural resonant frequency. As the tubes oscillate, the voltage generated from each pickoff coil creates a sine wave. This indicates the motion of one tube relative to the other.

With no flow, the sine waves are synchronized as shown in Fig. 1.29 with the inlet and outlet side moving at the same frequency. The Coriolis

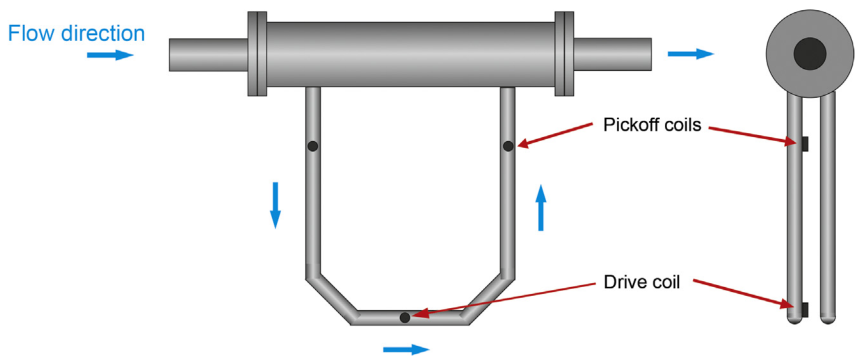


Fig. 1.28 Front and side view of Coriolis meter without the protective covering over the flow tubes.

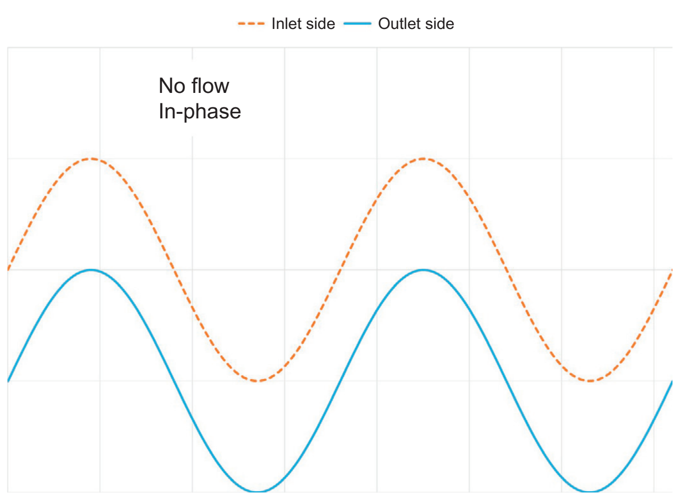


Fig. 1.29 Coriolis meter pickoff coil readings with no flow.

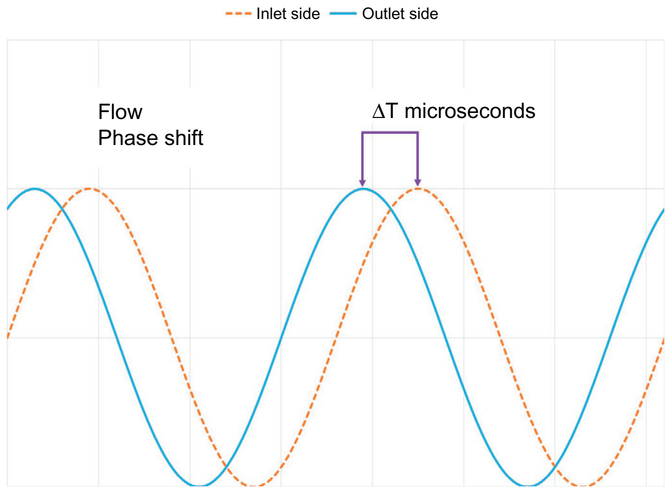


Fig. 1.30 Coriolis meter pickoff coil readings with flow.

effect as flow goes through the tubes causes the oscillation to change, and the oscillations will be out of sync as shown in Fig. 1.30. If the Coriolis meter is properly calibrated, the mass flow rate can be determined from the ΔT in Fig. 1.30.

The Coriolis meter will oscillate at a specific frequency depending upon the density of the fluid in the flow tubes. As the density increases, the oscillations slow down. With proper calibration, the density of the drilling fluid can be determined from the frequency. Mass flow rate is density times volume, so the volume rate of flow can be accurately determined. Flow into the wellbore from the mud pumps can be compared with flow out using the Coriolis meter. Discrepancies can be identified as possible kicks. Ultrasonic flow meters can also be used to measure flow rate out of the well and flow into the well.

Computer Programs

To aid in drilling MPD wells, hydraulic flow models have been developed to calculate equivalent circulating density [6,7], (ECD). Historically, ECD has been hard to consistently calculate even with sophisticated flow models. Therefore, flow models need to be calibrated with a pressure-while-drilling (PWD) sub in the bottom-hole assembly. MPD operations have proved that the annular pressures can be predicted relatively accurately using a combination of flow models and PWD data. Accurate drilling fluid flow rates and densities from instruments such as the Coriolis meter are used as input data. With flow models, wellbore pressures can be more accurately monitored while circulating, drilling, and making connections. In MPD operations, flow models are often used in combination with applied surface pressure to maintain a constant bottom-hole pressure.

Computer programs can also detect kicks while drilling, making connections, and tripping [8,9]. One of the primary indicators of a kick is the well flowing with the pump shutoff. It sounds simple, but it is often more complicated than that. Wells do not stop flowing immediately when the pump is turned off. In a relatively shallow well, it can stop flowing quickly. But as the well gets deeper, it may take several minutes for the well to quit flowing. Due to wellbore elasticity, drilling fluid compressibility, ballooning, etc., wells can flow more than 10 bbl while making a connection. Fig. 1.31 is an example of a well that flows back more than 20 bbl while making a connection. The well was drilling below 13,000 ft using a nonaqueous fluid (NAF). The pit alarm is set for +10 bbl, so the alarm will go off on every connection within 2–3 min. The drilling crew has to make the connection and monitor flow from the well. The drilling crew has to be familiar with how the well flows back on connections or what is “normal” because the

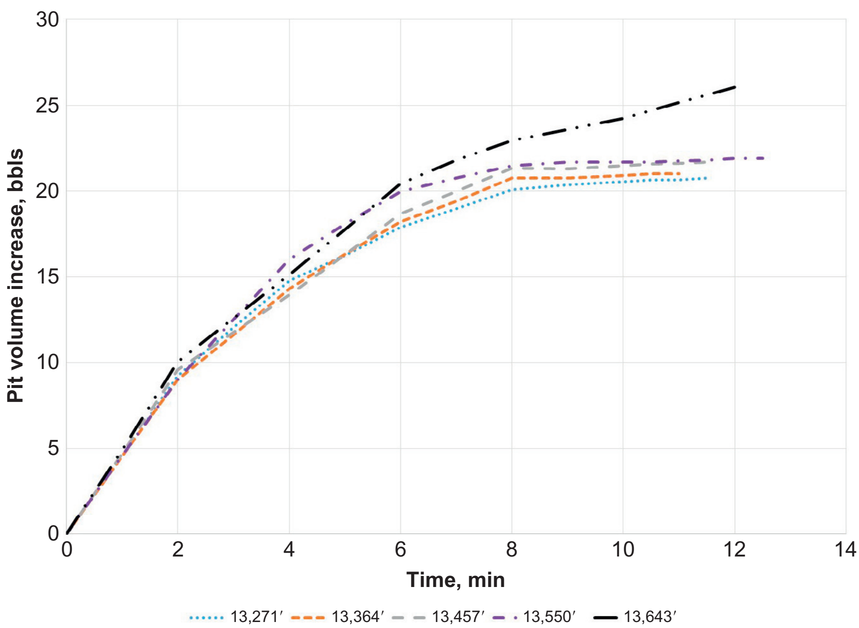


Fig. 1.31 Flow on connection with NAF in 8 ½ in. hole.

well never quits flowing in the time it takes to make a connection. And, it is difficult for the driller to physically make the connection while simultaneously monitoring flow. An assistant driller can help, but not all rigs have assistant drillers. Mud loggers may also be tasked with monitoring flow on connections.

In Fig. 1.31, is the connection at 13,643 ft a kick? It does not look any different until after 6 min. Then, it departs from the normal trend. The driller does not get to see the previous four connections. He just knows that the well typically flows more than 20 bbl on a connection. Without the four previous connections plotted on a screen, it would be difficult to judge if the well is kicking on the last connection. An algorithm can fingerprint the normal flow back on connections and can alert the driller if the flow back on a connection is statistically different from the fingerprinted connections.

With improved flow meters, flow during connections can also be fingerprinted and monitored by a computer algorithm. Depending upon the well and how long it takes to make a connection, the well may or may not quit flowing during the connection. Increased flow rate on connections can then be an indication that the well is flowing and the computer can alert the driller. Just like the pit gain, the computer compares the flow from the well on the previous connections to identify significant differences. Increased flow rate can be an earlier indication of a kick than the pit gain. Fig. 1.32 shows flow from a well that stops, and Fig. 1.33 shows where the flow does not stop indicating a possible kick [8].

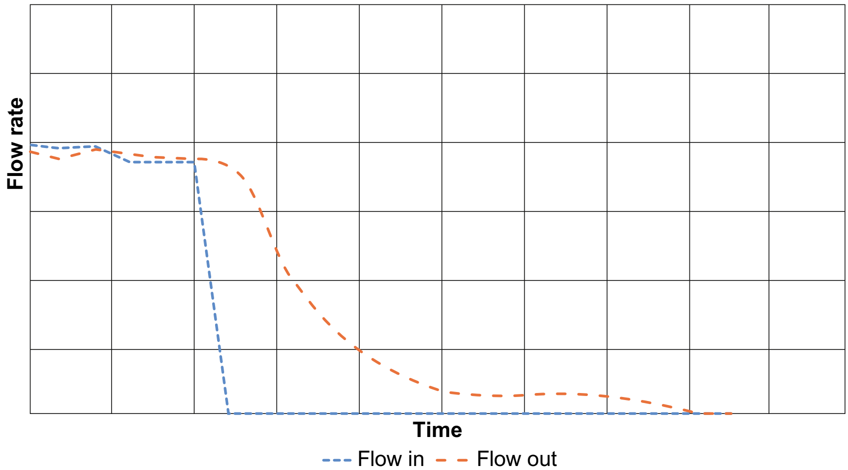


Fig. 1.32 Flow in versus flow out for a well where the flow stops on a connection.

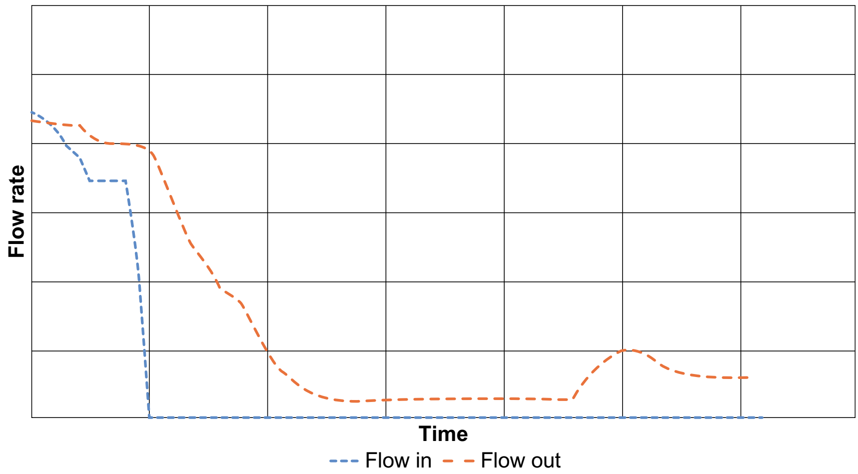


Fig. 1.33 Flow in versus flow out for a well where the flow does not stop on a connection.

Computer Controlled Chokes

Another advancement from MPD is computer-controlled chokes. In a full MPD system, pressure is maintained at the surface with a choke system and pump that is controlled by a computer. When the mud pumps are shut off to make a connection, a computer starts a surface pump that circulates drilling fluid into the wellbore under the rotating control device. Simultaneously, the computer adjusts the MPD choke to maintain the desired surface pressure [6]. While drilling, the computer adjusts the choke to maintain surface pressure or bottom-hole pressure based on the pump rate from the mud pumps. The same computer programs and computer-controlled chokes can be used if drilling a conventional well. The computer can adjust the choke to follow a drill pipe pressure schedule. If ECD software is being used, the computer can control the choke, maintaining a constant bottom-hole pressure. The software and computer-controlled choke have been routinely used in MPD operations to circulate out kicks, so it is proved technology.

The advent of MPD has added some capabilities to kick detection and circulating out a kick. Flow meters can measure actual flow rates from the well and measure the density of the drilling fluid in the returns. Computer algorithms can monitor flow and pit volumes to detect kicks sooner. Computer-controlled chokes can circulate out kicks by maintaining the proper back pressure on the well.

In order to use the equipment, it has to be rigged up and properly calibrated. With ECD software, calibration is continuous since mud properties change with time. It also has to be tested to make sure it is working properly, but that is the case with any well control equipment. Additionally, it can add significantly to operating costs. In a high-cost environment, the percentage of the total operating cost is low. But in a low-cost environment, the cost can be a significant percentage of the operating costs. A risk assessment will have to be performed to see if the mitigation costs are warranted.

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CHAPTER TWO

Classical Pressure Control Procedures while Drilling

24 September

0600–0630	Service rig.
0630–2130	Drilling 12,855–13,126 ft for 271 ft.
2130–2200	Pick up and check for flow. Well flowing. Shut well in.
2200–2300	Pump 35 barrels down drillpipe. Unable to fill drillpipe.
2300–2330	Observe well. 1000 psi on casing. 0 psi on drillpipe.
2330–0030	Pump 170 barrels down drillpipe using Barrel In—Barrel Out Method. Could not fill drillpipe. 0 psi on drillpipe. 1200 psi on casing at choke panel. Shut pump off. Check gauge on choke manifold. Casing pressure 4000 psi at choke manifold. Choke panel gauge pegged at 1200 psi. Well out of control.

This drilling report was taken from a recent blowout in the South Texas Gulf Coast. All of the men on the rig had been to a well control school and were well control certified. After the kick, it was decided to displace the influx using the barrel in—barrel out method, which is not taught in any well control school. As a result, control was lost completely, and an underground blowout followed.

Prior to 1960, the most common method of well control was known as the constant pit-level method or the barrel in—barrel out method. However, it was realized that if the influx was anything other than water, this method would be catastrophic. Consequently, classical pressure control procedures were developed. It is incredible that even today there are those in the field who continue to use the older, antiquated methods.

Ironically, there are instances when these methods are appropriate, and the classical methods are not. It is equally incredible that in some instances classical procedures are applied to situations that are completely

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inappropriate. If the actual situation is not approximated by the theoretical models used in the development of the classical procedures, the classical procedures are not appropriate. There is an obvious general lack of understanding. It is the purpose of this chapter to establish firmly the theoretical basis for the classical procedures and describe the classical procedures. The application of the theory must be strictly followed in the displacement procedure.

CAUSES OF WELL KICKS AND BLOWOUTS

A kick or blowout may result from one of the following:

1. Mud weight less than formation pore pressure
2. Failure to keep the hole full while tripping
3. Swabbing while tripping
4. Lost circulation
5. Mud cut by gas, water, or oil.

Mud Weight Less Than Formation Pore Pressure

There has been an emphasis on drilling with mud weights very near to and, in some instances, below formation pore pressures in order to maximize penetration rates. It has been a practice in some areas to take a kick to determine specific pore pressures and reservoir fluid composition. In areas where formation productivity is historically low (roughly less than one million standard cubic feet per day without stimulation), operators often drill with mud hydrostatics below the pore pressures.

Mud-weight requirements are not always known for certain areas. The ability of the industry to predict formation pressures has improved in recent years and is sophisticated. However, a North Sea wildcat was recently 9 lb/gal overbalanced, while several development wells in Central America were routinely 2 lb/gal underbalanced. Both used the very latest techniques to predict pore pressure while drilling. Many areas are plagued by abnormally pressured, shallow gas sands. Geologic correlation is always subject to interpretation and particularly difficult around salt domes.

Failure to Keep the Hole Full and Swabbing While Tripping

Failure to keep the hole full and swabbing are some of the most frequent causes of well control problems in drilling. This problem is discussed in depth in Chapter Three.

Lost Circulation

If returns are lost, the resulting loss of hydrostatic pressure will cause any permeable formation containing greater pressures to flow into the wellbore. If the top of the drilling fluid is not visible from the surface, as in the case in many instances, the kick may go unnoticed for some time. This can result in an extremely difficult well control situation.

One defense in these cases is to attempt to fill the hole with water in order that the well may be observed. Usually, if an underground flow is occurring, pressure and hydrocarbons will migrate to the surface within a few hours. In many areas, it is forbidden to trip out of the hole without returns to the surface. In any instance, tripping out of the hole without mud at the surface should be done with extreme caution and care, giving consideration to pumping down the annulus while tripping.

Mud Cut

Gas-cut mud has always been considered a warning signal, but not necessarily a serious problem. Calculations demonstrate that severe gas-cut mud causes modest reductions in bottom-hole pressures because of the compressibility of the gas. An incompressible fluid such as oil or water can cause more severe reductions in total hydrostatic and has caused serious well control problems when a productive oil or gas zone is present.

INDICATIONS OF A WELL KICK

We normally think of kicks, bubbles, and blowouts occurring while drilling or tripping. In reality, that is generally true. However, it is also true that kicks, bubbles, and blowouts can occur during other phases of the operation. The focus of this writing is on events that happen during the actual drilling operation. However, we must be vigilant at all times when the rig is on the hole.

The blowout on the deepwater horizon is a tragic example. The rig had been idle for several days, while logging operations were successfully completed with no indication of underbalance. It was abundantly clear to all involved that a zone had been drilled that was capable of flowing oil and gas at relatively high flow rates. The reservoir characteristics were recorded, and the reservoir pressure was known.

After logging, a long, tapered string of $9\frac{5}{8}$ in. casing on top and 7 in. casing on bottom was run. There were four shoe joints beneath the self-filling float collar. There were some problems activating the float collar.

The casing was cemented in place and landed in the subsea wellhead. The casing and the seals in the wellhead were successfully pressure tested. Surely, the well was contained and under control.

All that remained was to partially displace the hole with seawater and temporarily abandon the well. Accordingly, the drill pipe with a stinger on the end was run to 8367 ft into the hole, and seawater was pumped down the drill string and up the annulus with the intention of displacing the drilling mud from the top of the well and the riser.

The well was being displaced with seawater, and the mud being recovered was being off-loaded to vessels. The operation was being monitored by two independent monitoring systems. Both systems were available to the rig crew on the rig floor, and one was available to a dedicated dog house adjacent to the rig floor. Both were monitoring all the classical indications of an influx—pump rates, pit volumes, pump pressures, flow rates, etc.

As a precaution, a negative test was planned. The negative test was intended to simulate the abandoned condition of the well and test the underbalanced system for pressure integrity. In most negative tests, the drill pipe is displaced with seawater, the annulus is isolated, and the drill pipe is then opened to check for flow or monitored to check for pressure. For some unexplained reasons, the negative test in this instance specified that the kill line on the subsea stack be monitored for flow and/or pressure. This requirement presents unnecessary complications.

To accomplish that objective, the choke and kill lines were first displaced to seawater. Then utilizing the stroke counter, the drill pipe and annulus to the top of the subsea stack were displaced to seawater using the mud pump stroke counter. According to the plan, roughly 6100 pump strokes were required to place the interface between the drilling mud and the seawater 12 ft above the subsea blowout preventer stack. Utilizing the stroke counter for accuracy is optimistic at best due to the variation in mud pump efficiency.

Accordingly, seawater was pumped in anticipation of covering the subsea blowout preventer stack, and the annular preventer was closed. When the drill pipe was opened, the annular leaked (blowout preventers are designed to maintain pressure from below and not from above), the fluid level in the annulus dropped, and seawater flowed to the surface. The drill pipe was shut in, and the pressure on the drill pipe increased to approximately 1200 psi.

The closing pressure on the annular was increased, the annulus was filled with roughly 50 bbl of mud, and the procedure was repeated. With the drill pipe shut in, the pressure on the drill pipe again increased to approximately

1200 psi. When the kill line was opened at the subsea stack, the pressure on the drill pipe suddenly increased an additional 200 psi to 1400 psi and flatlined. There was no flow from the kill line.

The anomalous pressure on the drill pipe was rationalized. There was no flow or pressure on the kill line. Therefore, the negative test was declared to be successful.

At about 7:55 p.m., the crew continued to displace the riser to seawater in preparation for spotting a cement plug at the surface and temporarily abandoning the well. Beginning about an hour later, the flow parameters began to behave erratically.

For the first roughly 1 h of the displacement of the 14.2 ppg drilling mud by the 8.4 ppg seawater, the standpipe pressure declined as would be expected. Then, beginning at about 9 p.m., the drill pipe pressure began to increase as the 14.2 ppg drilling mud was being displaced by the 8.4 ppg seawater. There was no response by anyone on the rig or no indication of recognition of an anomaly.

Beginning about 9 p.m., the drill pipe pressure began to increase as the heavy mud was being displaced by the much lighter seawater. The displacement procedure was interrupted for 6 min at roughly 9:10 in order to conduct a sheen test. During that 6 min period with the pumps off, the pressure on the drill pipe increased approximately 250 psi.

After the sheen test, the displacement operation was continued, and the drill pipe pressure continued to increase. At roughly 9:30 p.m., the pumps were shut down to investigate the anomalous pressure behavior. Over the next 5 min, the drill pipe pressure increased about 500 psi, while the pumps remained shut down.

For unknown reasons, the crew then bled pressure from the drill pipe for 2 min. At about 9:42 p.m., as the crew was lining up to the trip tank to check for flow, the well erupted, sending gas, oil, and drilling mud over the crown block. At 9:43 p.m., one of the annulars was closed, and at 9:47 p.m., the rams were closed. By this time, calculations estimate that the well was flowing in excess of 100 bbl/min. Most likely, the rams were cut out before they could close and seal. The rest is history.

The point of the story is that the industry not only has trained rig crews to recognize anomalies while drilling and tripping but also needs to emphasize the importance of being vigilant for anomalies at all times when the rig is over the hole.

An incident such as this defies the imagination! The long string of casing had been run, cemented, and tested. Sufficient time had elapsed for the cement to set. If ever a well could be expected to be contained, it was at this point in the operation. How could anything possibly go wrong? But, it did!

This should be the instruction for the senior representative on the rig floor of the drilling contractor. **WHEN IN DOUBT, CHECK IT OUT!** Anytime, the rig is on the hole, and parameters such as drill pipe pressure, flow rate, and pit volume become inconsistent or anomalous, stop the operation, check for flow or shut the blowout preventer, and check for pressure.

Early warning signals are as follows:

1. Sudden increase in drilling rate
2. Increase in fluid volume at the surface, which is commonly termed a pit-level increase or an increase in flow rate
3. Change in pump pressure
4. Reduction in drill pipe weight
5. Gas-, oil-, or water-cut mud.

Sudden Increase in Drilling Rate

Generally, the first indication of a well kick is a sudden increase in drilling rate or a "drilling break," which suggests that a porous formation may have been penetrated. Crews should be alerted that, in the potential pay interval, no more than some minimal interval (usually 2–5 ft) of any drilling break should be penetrated. This is one of the most important aspects of pressure control. Many multimillion-dollar blowouts could have been avoided by limiting the open interval.

When drilling with PDC bits, it becomes more complicated. PDC bits drill formations faster, and porous formation may not drill any faster than the shale around it. Often enough, the PDC bit will drill the shale faster and slowdown while drilling through sand and carbonate. The potential pay zone can sometimes have a reverse drilling break.

Increase in Pit Level or Flow Rate

A variation of bit type may mask a drilling break. In that event, the first warning may be an increase in flow rate or pit level caused by the influx of formation fluids. Depending on the productivity of the formation, the influx may be rapid or imperceptible. Therefore, the influx could be considerable before being noticed. No change in pit level or flow rate should be ignored.

Change in Pump Pressure

A decrease in pump pressure during an influx is caused by the reduced hydrostatic in the annulus. Most of the time, one of the aforementioned indications will have manifested itself prior to a decrease in pump pressure.

Reduction in Drillpipe Weight

The reduction in string weight occurs with a substantial influx from a zone of high productivity. Again, the other indicators will probably have manifested themselves prior to or in conjunction with a reduction in drill pipe weight.

Gas, Oil, or Water-Cut Mud

Caution should be exercised when gas-, oil-, or water-cut mud is observed. Normally, this indicator is accompanied by one of the other indicators if the well is experiencing an influx.

Summary

An excellent example of the classical indications of a kick is given as shown in Fig. 2.1. This is an actual example from an operation in the US mid-continent area. The driller and the tool pusher had been to a well control school on at least one occasion.

While drilling at a depth of 9150 ft at 3 a.m., there was a noticeable increase in penetration rate from roughly 20–100 ft/h at 3:04 a.m.. The flow out from the well increased significantly at about 3:01 a.m.. The pump pressure began to decline at 3:03 a.m.. By 3:05 a.m., there had been a 10 bbl gain in pit level. Had the crew responded as recommended by the API, the influx would have been no more than 20 bbl and could have been easily handled. The total pit gain was 118 bbl in roughly 30 min.

The driller was in constant contact with the tool pusher from the time the well kicked. He stopped drilling and picked up 60 ft off bottom 15 min after the well kicked. However, he did not shut the blowout preventers. Twenty-two minutes after the kick began, the pit gain was roughly 80 bbl when the driller picked up to 90 ft off bottom, latched the brake down, and ran. The well caught fire. The company representative was asleep in his quarters at the time of the kick. He was awakened by the commotion, went to the accumulator, and closed the pipe rams.

Unfortunately, the crew failed to respond as trained. Fortunately, there were no injuries.

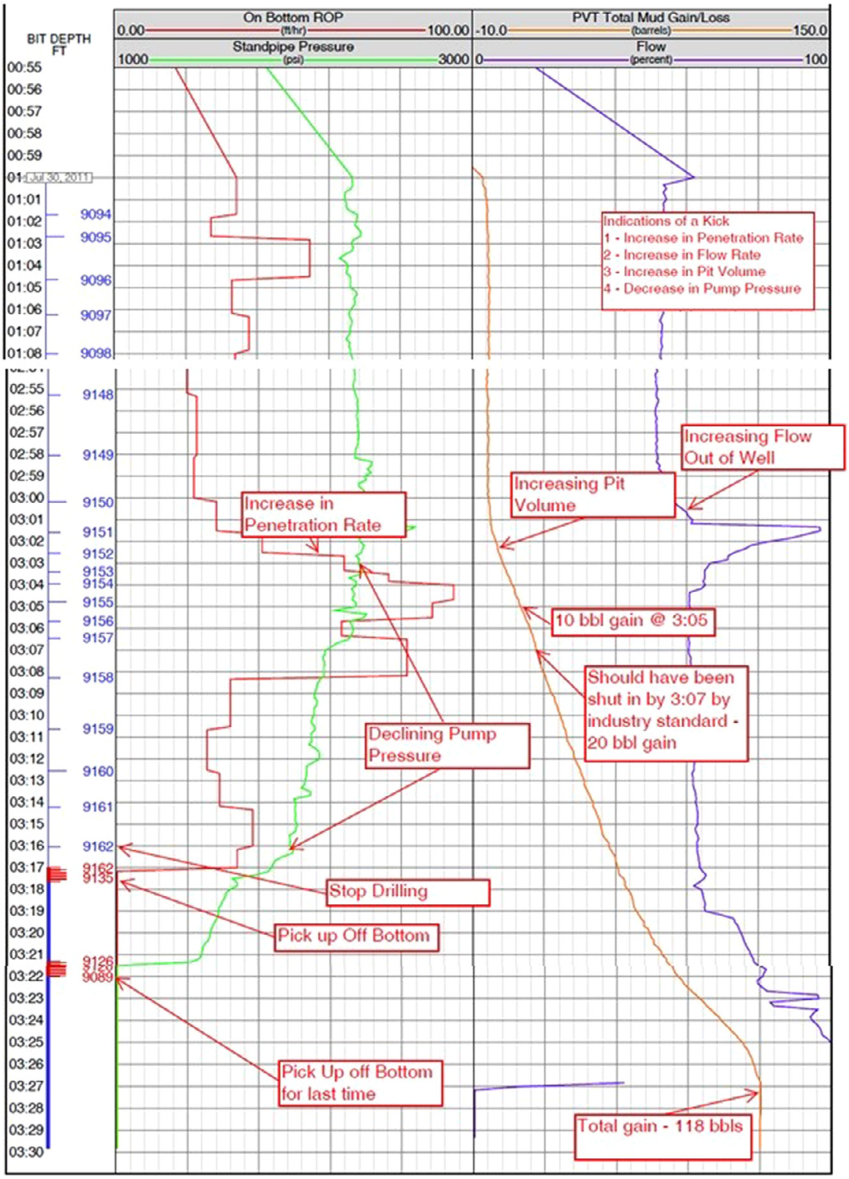

Fig. 2.1 Drilling data recorder information for a well kick.

SHUT-IN PROCEDURE

When any of these warning signals are observed, the crew must immediately proceed with the established shut-in procedure. The crew must be thoroughly trained in the procedure to be used, and that procedure should be posted in the dog house. It is imperative that the crew be properly trained and react to the situation. API RP 59 [1] recommends that the crew be trained to shut the well in within 2 min. The success of the well control operation depends upon the response of the crew at this most critical phase.

A typical shut-in procedure is as follows:

1. Drill no more than 3 ft of any drilling break.
2. Pick up off bottom, space out, and shut off the pump.
3. Check for flow.
4. If flow is observed, shut in the well by opening the choke line, closing the pipe rams, and closing the choke, pressure permitting.
5. Record the pit volume increase, drill pipe pressure, and annulus pressure. Monitor and record the drill pipe and annular pressures at 15 min intervals.
6. Close annular preventer; open-pipe rams.
7. Prepare to displace the kick.

The number of feet of a drilling break to be drilled prior to shutting in the well can vary from area to area. However, an initial drilling break of 2–5 ft is common. The drill pipe should be spaced out to insure that no tool joints are in the blowout preventers. This is especially important on offshore and floating operations. On land, the normal procedure would be to position a tool joint at the connection position above the rotary table to permit easy access for alternate pumps or wire-line operations. The pump should be left on while positioning the drill pipe. The fluid influx is distributed and not in a bubble. In addition, there is less chance of initial bit plugging.

When observing the well for flow, the question is "how long should the well be observed?" The obvious answer is that the well should be observed as long as necessary to satisfy the observer of the condition of the well. Generally, 15 min or less is required. If oil muds are being used, the observation period should be lengthened. If the well is deep, the observation period should be longer than for a shallow well.

If the drilling break is a potentially productive interval but no flow is observed, it may be prudent to circulate bottoms up before continuing drilling in order to monitor and record carefully such parameters as time, strokes, flow rate, and pump pressure for indications of potential well control problems. After it is determined that the well is under control, drill another increment of the drilling break and repeat the procedure. Again, there is flexibility in the increment to be drilled. The experience gained from the first increment must be considered. A second increment of 2–5 ft is common. Circulating out may not be necessary after each interval even in the productive zone; however, a short circulating period will disperse any influx. Repeat this procedure until the drilling rate returns to normal and the annulus is free of formation fluids.

Whether the annular preventer or the pipe rams are closed first is a matter of operator choice. The closing time for each blowout preventer must be considered along with the productivity of the formation being penetrated. The objective of the shut-in procedure is to limit the size of the kick. If the annular requires twice as much time to close as the pipe rams and the formation is prolific, the pipe rams maybe the better choice. If both blowout preventers close in approximately the same time, the annular is the better choice since it will close on anything.

Shutting in the well by opening the choke, closing the blowout preventers, and closing the choke is known as a "soft shut-in." The alternative is known as a "hard shut-in," which is achieved by merely closing the blowout preventer on the closed choke line. The primary argument for the hard shut-in is that it minimizes influx volume, and influx volume is critical to success. The hard shut-in became popular in the early days of well control.

Before the advent of modern equipment with remote hydraulic controls, opening choke lines and chokes was time-consuming and could permit significant additional influx. With modern equipment, all hydraulic controls are centrally located, and critical valves are hydraulically operated. Therefore, the shut-in is simplified, and the time is reduced. In addition, blowout preventers, like valves, are made to be open or closed, while chokes are made to restrict flow. In some instances, during hard shut-in, the fluid velocity through closing blowout preventers has been sufficient to cut out the preventer before it could be closed effectively.

In the young rocks such as are commonly found in offshore operations, the consequences of exceeding the maximum pressure can be grave in that the blowout can fracture to the surface outside the casing. The blowout then becomes uncontrolled and uncontrollable. Craters can consume jack-up rigs and platforms. The plight of the floating rig can be even more grim due to the loss of buoyancy resulting from gas in the water.

The most infamous and expensive blowouts in industry history were associated with fracturing to the surface from under surface casing. It is often argued that fracturing to the surface can be avoided by observing the surface pressure after the well is closed in and opening the well if the pressure becomes too high. Unfortunately, in most instances, there is insufficient time to avoid fracturing at the shoe. All things considered, the soft shut-in is the better procedure.

In the event the pressure at the surface reaches the maximum permissible surface pressure, a decision must be made either to let the well blow out underground or to vent the well to the surface. Either approach can result in serious problems. With only surface casing set to a depth of less than 3600 ft, the best alternative is to open the well and permit it to flow through the surface equipment. This procedure can result in the erosion of surface equipment. However, more time is made available for rescue operations and repairs to surface equipment. It also simplifies kill operations.

There is no history of a well fracturing to the surface with pipe set below 3600 ft. Therefore, with pipe set below 3600 ft, the underground blowout is an alternative. It is argued that an underground flow is not as hazardous as a surface flow in some offshore and land operations. When properly rigged up, flowing the well to the surface under controlled conditions is the preferred alternative. A shut-in well that is blowing out underground is difficult to analyze and often more difficult to control.

The maximum permissible shut-in surface pressure is the lesser of 80%–90% of the casing burst pressure and the surface pressure required to produce fracturing at the casing shoe. The procedure for determining the maximum permissible shut-in surface pressure is illustrated in Example 2.1:

Example 2.1

Given:

Surface casing = 2000 ft $8\frac{5}{8}$ in.
Internal yield = 2470 psi
Fracture gradient, $F_g = 0.76$ psi/ft
Mud density, $\rho = 9.6$ ppg
Mud gradient, $\rho_m = 0.5$ psi/ft
Wellbore schematic = Fig. 2.2

Required:

Determine the maximum permissible surface pressure on the annulus, assuming that the casing burst is limited to 80% of the design specification.

Solution:

$$80\%\ \text{burst} = 0.8(2470\ \text{psi}) = 1976\ \text{psi}$$

$$P_{frac} = P_a(\text{Maximum}) + \rho_m D_{sc} \tag{2.1}$$

where
P_{frac} = fracture pressure, psi
P_a = annulus pressure, psi

Continued

Example 2.1—cont'd

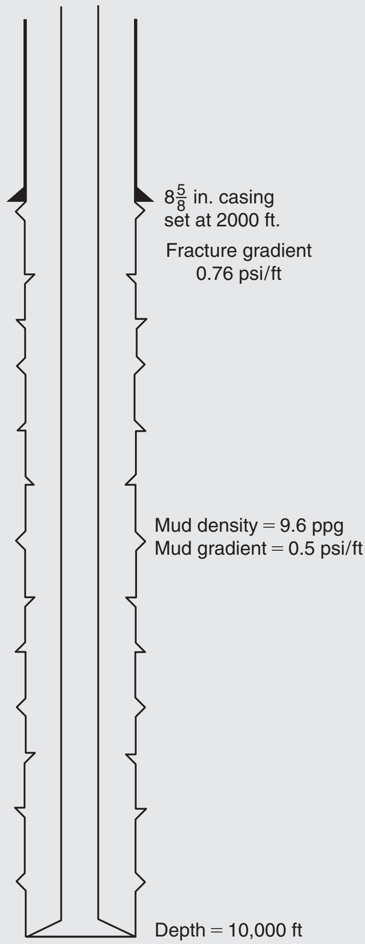

Fig. 2.2 Wellbore schematic.

ρ_m = mud gradient, psi/ft
D_{sc} = depth to the casing shoe, ft
Therefore,

$$\begin{aligned} P_a(\text{Maximum}) &= P_{frac} - \rho_m D_{sc} \\ &= 0.76(2000) - 0.5(2000) \\ &= 520\,\text{psi} \end{aligned}$$

Therefore, the maximum permissible annular pressure at the surface is 520 psi, which is the pressure that would produce formation fracturing at the casing seat.

Recording the gain in pit volume, drill pipe pressure, and annulus pressure initially and over time is very important to controlling the kick. As will be seen in the discussion of special problems in Chapter Four, the surface pressures are critical for determining the condition of the well and the potential success of the well control procedure. Analysis of the gain in the surface volume in consideration of the casing pressure is critical in defining the potential for an underground blowout.

In some instances, due to a lack of familiarity with the surface equipment, crews have failed to shut in the well completely. When the pit volume continued to increase, the oversight was detected, and the well shut in. Recording the surface pressures over time is extremely important. Gas migration, which is also discussed in Chapter Four, will cause the surface pressures to increase over time. Failure to recognize the resultant super pressuring can result in the failure of the well control procedure.

These procedures are fundamental to pressure control. They are the responsibility of the rig crew and should be practiced and studied until they become as automatic as breathing. The entire operation depends upon the ability of the driller and crew to react to a critical situation. Now, the well is under control, and the kill operation can proceed to circulate out the influx.

ARE CLASSICAL WELL CONTROL PROCEDURES APPLICABLE?

At this point, the well is safely shut in without exceeding the maximum permissible annulus pressure. The question then becomes—can the influx be circulated out without breaking down the open hole, losing circulation and losing the well? Stated another way—at what point in the operation is the pressure at the casing shoe at the maximum and will it exceed the fracture pressure at the casing shoe?

Understanding the concept of kick tolerance is critical to make this determination. The kick tolerance is the volume of influx that can be circulated to the surface without exceeding the frac pressure at the weakest point in the open hole, which is usually the fracture pressure at the last casing shoe. The kick tolerance or maximum influx volume should be determined in advance and updated regularly as the well is drilled. And if the influx volume exceeds that determined by the kick tolerance calculations, classical pressure control procedures may not be applicable.

Why do we say—may not be applicable? The model for determining the kick tolerance assumes that the influx is in a continuous bubble. That may or may not be true. Often, the influx is in one continuous bubble and behaves accordingly. However, it is often true that the influx is strung out due to the fact that the well is being circulated continuously. In that case, the actual kick tolerance may be greater than the value theoretically determined. And, when oil-base muds are being used, natural gas is infinitely soluble in oil. Therefore, that will impact the actual kick tolerance.

The kick tolerance or volume of influx that can be circulated to the surface using classical pressure control procedures, commonly referred to as the driller's method and the wait-and-weight method, without losing circulation is a function of the density of the influx, the geometry of the annulus, the depth of the casing shoe, the fracture pressure at the casing shoe, and the intensity of the kick. The intensity of the kick is the underbalance when the kick is taken. The kick tolerance calculations result in a range of influx volumes corresponding to the underbalance.

Consider the wellbore configuration and conditions beginning with Example 2.2 and used throughout this book. Using methodology described in Chapter Four, the kick tolerance would be defined by the diagram presented as Fig. 2.3. As shown in Fig. 2.3, the intensity of the kick is reflected in the shut-in drill pipe pressure, which is the difference between the hydrostatic pressure of the mud and the formation pore pressure.

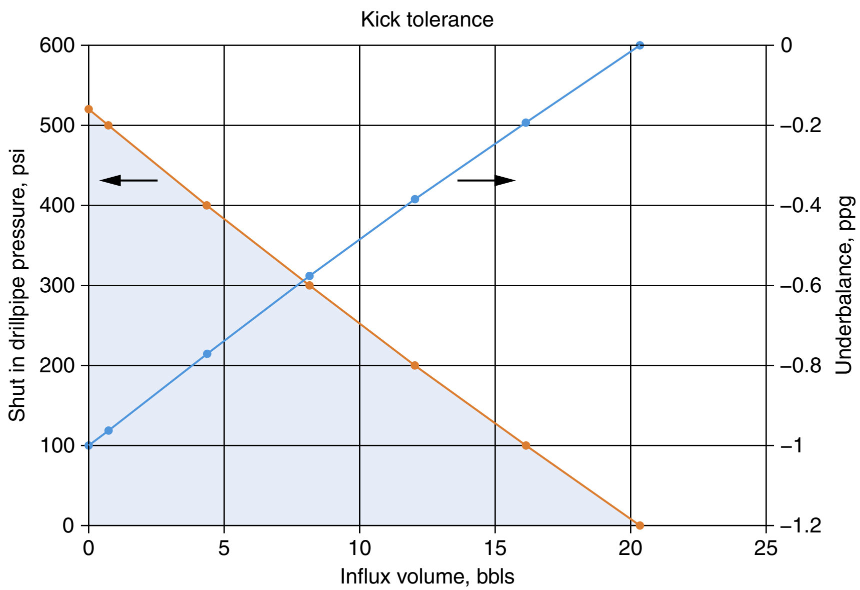

Fig. 2.3 Graph showing kick tolerance calculations.

In Fig. 2.3, the kick tolerance is zero if the well is underbalanced by 1 ppg and the shut-in drill pipe pressure is 520 psi since, as shown in Example 2.1, the maximum permissible annulus pressure for this example is 520 psi. If the well is overbalanced, such as a kick has been swabbed into the hole, an influx of as much as 25 bbl can be safely circulated to the surface.

The kick tolerance envelope is that triangular shaded area in Fig. 2.3. Any point defined by a combination of shut-in drill pipe pressure and corresponding influx volume that falls within the kick tolerance envelope can be safely circulated out of the hole. Any situation defined by a point falling outside the kick tolerance envelope will most likely result in lost circulation and difficulty controlling the well.

CIRCULATING OUT THE INFLUX

Theoretical Considerations

Gas Expansion

Prior to the early 1960s, an influx was circulated to the surface by keeping the pit-level constant. This was also known as the barrel in—barrel out method. Some insist on using this technique today although it is no more successful now than then. If the influx was mostly liquid, this technique was successful. If the influx was mostly gas, the results were disastrous. When a proponent of the constant pit-level method was asked about the results, he replied, "oh, we just keep pumping until something breaks!" Invariably, something did break, as illustrated in the drilling report at the beginning of this chapter.

In the late 1950s and early 1960s, some began to realize that this barrel in—barrel out technique could not be successful. If the influx was gas, the gas had to be permitted to expand as it came to the surface. The basic relationship of gas behavior is given in Eq. (2.2):

$$PV = znRT \tag{2.2}$$

where

P = pressure, psia
V = volume, ft^3
z = compressibility factor
n = number of moles
R = units conversion constant
T = temperature, R

For the purpose of studying gas under varying conditions, the general relationship can be extended to another form as given in Eq. (2.3):

$$\frac{P_1 V_1}{z_1 T_1} = \frac{P_2 V_2}{z_2 T_2} \tag{2.3}$$

1 = denotes conditions at any point

2 = conditions at any point other than point 1

By neglecting changes in temperature, T, and compressibility factor, z, Eq. (2.3) can be simplified into Eq. (2.4) as follows:

$$P_1 V_1 = P_2 V_2 \tag{2.4}$$

In simple language, Eq. (2.4) states that the pressure of a gas multiplied by the volume of the gas is constant. The significance of gas expansion in well control is illustrated by Example 2.2:

Example 2.2

Given:

Wellbore schematic = Fig. 2.4

Mud density, $\rho = 9.6$ ppg

Mud gradient, $\rho_m = 0.5$ psi/ft

Well depth, $D = 10{,}000$ ft

Conditions described in Example 2.1

The wellbore is a closed container.

1 ft^3 of gas enters the wellbore.

Gas enters at the bottom of the hole, which is point 1.

Required:

1. Determine the pressure in the gas bubble at point 1.
2. Assuming that the 1 ft^3 of gas migrates to the surface of the closed container (point 2) with a constant volume of 1 ft^3, determine the pressure at the surface, the pressure at 2000 ft, and the pressure at 10,000 ft.

Solution:

1. The pressure of the gas, P_1, at point 1, which is the bottom of the hole, is determined by multiplying the gradient of the mud (psi/ft) by the depth of the well.

$$P_1 = \rho_m D$$
$$P_1 = 0.5(10{,}000) \tag{2.5}$$
$$P_1 = 5000\,\text{psi}$$

Example 2.2—cont'd

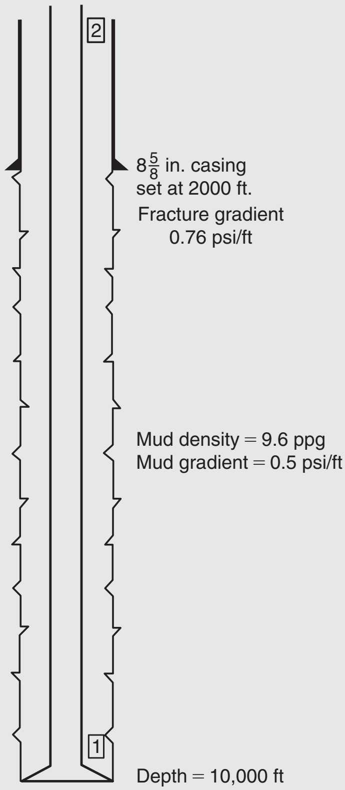

Fig. 2.4 Wellbore schematic—closed container.

2. The pressure in the 1 ft^3 of gas at the surface (point 2) is determined using Eq. (2.4):

$$P_1 V_1 = P_2 V_2$$
$$(5000)(1) = P_2(1)$$
$$P_{surface} = 5000\,\text{psi}$$

Determine the pressure at 2000 ft.

$$P_{2000} = P_2 + \rho_m(2000)$$
$$P_{2000} = 5000 + 0.5(2000)$$
$$P_{2000} = 6000\,\text{psi}$$

Determine the pressure at the bottom of the hole.

Continued

Example 2.2—cont'd

$$P_{10,000} = \rho_m(10,000)$$
$$P_{10,000} = 5000 + 0.5(10,000)$$
$$P_{10,000} = 10,000\,\text{psi}$$

As illustrated in Example 2.2, the pressures in the well become excessive when the gas is not permitted to expand. The pressure at 2000 ft would build to 6000 psi if the wellbore was a closed container. However, the wellbore is not a closed container, and the pressure required to fracture the wellbore at 2000 ft is 1520 psi. When the pressure at 2000 ft exceeds 1520 psi, the container will rupture, resulting in an underground blowout.

The goal in circulating out a gas influx is to bring the gas to the surface, allowing the gas to expand to avoid rupturing the wellbore. At the same time, there is the need to maintain the total hydrostatic pressure at the bottom of the hole at the reservoir pressure in order to prevent additional influx of formation fluids. As will be seen, classical pressure control procedures routinely honor the second condition of maintaining the total hydrostatic pressure at the bottom of the hole equal to the reservoir pressure and ignore any consideration of the fracture pressure at the shoe.

The U-tube Model

All classical displacement procedures are based on the U-tube model illustrated in Fig. 2.5. It is important to understand this model and premise. Too often, field personnel attempt to apply classical well control procedures to nonclassical problems. If the U-tube model does not accurately describe the system, classical pressure control procedures cannot be relied upon.

As illustrated in Fig. 2.5, the left side of the U-tube represents the drill pipe, while the right side of the U-tube represents the annulus. Therefore, the U-tube model describes a system where the bit is on bottom and it is possible to circulate from bottom. If it is not possible to circulate from bottom, classical well control concepts are meaningless and not applicable. This concept is discussed in detail in Chapter Four.

As further illustrated in Fig. 2.5, an influx of formation fluids has entered the annulus (right side of the U-tube). The well has been shut in, which means that the system has been closed. Under these shut-in conditions, there is static pressure on the drill pipe, which is denoted by P_{dp}, and static pressure on the annulus, which is denoted by P_a. The formation fluid, ρ_f, has entered the annulus and occupies a volume defined by the area of the annulus and the height, h, of the influx.

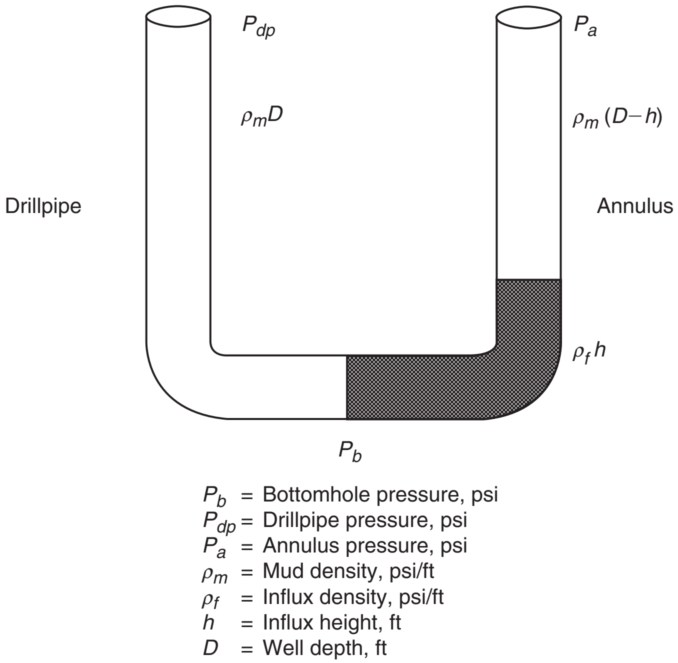

Fig. 2.5 The U-tube model.

An inspection in Fig. 2.5 indicates that the drill pipe side of the U-tube model is simpler to analyze since the pressures are only influenced by mud of known density and pressure on the drill pipe that is easily measured. Under static conditions, the bottom-hole pressure is easily determined utilizing Eq. (2.6):

$$P_b = \rho_m D + P_{dp} \tag{2.6}$$

where

P_b = bottom-hole pressure, psi
ρ_m = mud gradient, psi/ft
D = well depth, ft
P_{dp} = shut-in drill pipe pressure, psi

Eq. (2.6) describes the shut-in bottom-hole pressure in terms of the total hydrostatic on the drill pipe side of the U-tube model. The shut-in bottom-hole pressure can also be described in terms of the total hydrostatic pressure on the annulus side of the U-tube model as illustrated by Eq. (2.7):

$$P_b = \rho_f h + \rho_m (D - h) + P_a \tag{2.7}$$

where

P_b = bottom-hole pressure, psi
ρ_m = mud gradient, psi/ft
D = well depth, ft
P_a = shut-in casing pressure, psi
ρ_f = gradient of influx, psi/ft
h = height of the influx, ft

Classical well control procedures, no matter what terminology is used, must keep the shut-in bottom-hole pressure, P_b, constant to prevent additional influx of formation fluids while displacing the initial influx to the surface. Obviously, the equation for the drill pipe side (Eq. 2.6) is the simpler, and all of the variables are known; therefore, the drill pipe side is used to control the bottom-hole pressure, P_b.

With the advent of pressure control technology, the necessity of spreading that technology presented an awesome task. Simplicity was in order, and the classical driller's method for displacing the influx from the wellbore without permitting additional influx was developed.

The Driller's Method

The driller's method of displacement is simple and requires minimal calculations. The recommended procedure is as follows:

Step 1

On each tour, read and record the standpipe pressure at several rates in strokes per minute (spm), including the anticipated kill rate for each pump.

Step 2

After a kick is taken and prior to pumping, read and record the drill pipe and casing pressures. Determine the anticipated pump pressure at the kill rate using Eq. (2.8):

$$P_c = P_{ks} + P_{dp} \tag{2.8}$$

where

P_c = circulating pressure during displacement, psi
P_{ks} = recorded pump pressure at the kill rate, psi
P_{dp} = shut-in drill pipe pressure, psi

Important: If in doubt at any time during the entire procedure, shut in the well, read and record the shut-in drill pipe pressure and the shut-in casing pressure, and proceed accordingly.

Step 3

Bring the pump to a kill speed, keeping the casing pressure constant at the shut-in casing pressure. This step should require less than 5 min.

Step 4

Once the pump is at a satisfactory kill speed, read and record the drill pipe pressure. Displace the influx, keeping the recorded drill pipe pressure constant.

Step 5

Once the influx has been displaced, record the casing pressure and compare with the original shut-in drill pipe pressure recorded in Step 1. It is important to note that, if the influx has been completely displaced, the casing pressure should be equal to the original shut-in drill pipe pressure.

Step 6

If the casing pressure is equal to the original shut-in drill pipe pressure recorded in Step 1, shut in the well by keeping the casing pressure constant while slowing the pumps. If the casing pressure is greater than the original shut-in drill pipe pressure, continue circulating for an additional circulation, keeping the drill pipe pressure constant, and then shut in the well, keeping the casing pressure constant while slowing the pumps.

Step 7

Read, record, and compare the shut-in drill pipe and casing pressures. If the well has been properly displaced, the shut-in drill pipe pressure should be equal to the shut-in casing pressure.

Step 8

If the shut-in casing pressure is greater than the shut-in drill pipe pressure, repeat Steps 2–7.

Step 9

If the shut-in drill pipe pressure is equal to the shut-in casing pressure, determine the density of the kill-weight mud, ρ_1, using Eq. (2.9) (Note that no "safety factor" is recommended or included):

$$\rho_1 = \frac{\rho_m D + P_{dp}}{0.052D} \tag{2.9}$$

where

ρ_1 = density of the kill-weight mud, ppg
ρ_m = gradient of the original mud, psi/ft
P_{dp} = shut-in drill pipe pressure, psi
D = well depth, ft

Step 10

Raise the mud weight in the suction pit to the density determined in Step 9.

Step 11

Determine the number of strokes to the bit (STB) by dividing the capacity of the drill string in barrels by the capacity of the pump in barrels per stroke according to Eq. (2.10):

$$STB = \frac{C_{dp} l_{dp} + C_{hw} l_{hw} + C_{dc} l_{dc}}{C_p} \tag{2.10}$$

where

STB = strokes to the bit, stk
C_{dp} = capacity of the drill pipe, bbl/ft
C_{hw} = capacity of the heavyweight drill pipe, bbl/ft
C_{dc} = capacity of the drill collars, bbl/ft
l_{dp} = length of the drill pipe, ft
l_{hw} = length of the heavyweight drill pipe, ft
l_{dc} = length of the drill collars, ft
C_p = pump capacity, bbl/stk

Step 12

Bring the pump to speed, keeping the casing pressure constant.

Step 13

Displace the kill-weight mud to the bit, keeping the casing pressure constant.

Warning: Once the pump rate has been established, no further adjustments to the choke should be required. The casing pressure should remain constant at the initial shut-in drill pipe pressure. If the casing pressure begins to rise, the procedure should be terminated, and the well shut in.

Step 14

After pumping the number of strokes required for the kill mud to reach the bit, read and record the drill pipe pressure.

Step 15

Displace the kill-weight mud to the surface, keeping the drill pipe pressure constant.

Step 16

With kill-weight mud to the surface, shut in the well by keeping the casing pressure constant while slowing the pumps.

Step 17

Read and record the shut-in drill pipe pressure and the shut-in casing pressure. Both pressures should be 0.

Step 18

Open the well, and check for flow.

Step 19

If the well is flowing, repeat the procedure.

Step 20

If no flow is observed, raise the mud weight to include the desired trip margin and circulate until the desired mud weight is attained throughout the system.

The discussion of each step in detail follows:

Step 1

On each tour, read and record the standpipe pressure at several flow rates in strokes per minute (spm), including the anticipated kill rate for each pump.

Experience has shown that one of the most difficult aspects of any kill procedure is bringing the pump to speed without permitting an additional influx or fracturing the casing shoe. This problem is compounded by attempts to achieve a precise kill rate. There is nothing magic about the kill rate used to circulate out a kick.

In the early days of pressure control, surface facilities were inadequate to bring an influx to the surface at a high pump speed. Therefore, one-half normal speed became the arbitrary rate of choice for circulating the influx to the surface. However, if only one rate such as the one-half speed is acceptable, problems can arise when the pump speed is slightly less or slightly more than the precise one-half speed. The reason for the potential problem is that the circulating pressure at rates other than the kill rate is unknown. Refer to further discussion after Step 4.

The best procedure is to record and graph several flow rates and corresponding pump pressures as illustrated in Fig. 2.6. It is assumed in Examples 2.3 and 2.4 that the kill speed used is 30 stk/min. However, the actual pump speed used need not be exactly 30 stk/min.

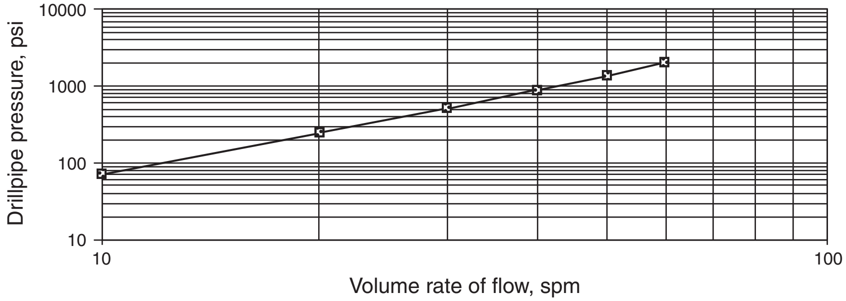

Fig. 2.6 Pressure vs. volume diagram, Example 2.3.

The drill pipe pressure corresponding to the actual pump speed being used could be verified using Fig. 2.6.

Step 2

After a kick has been taken and prior to pumping, read and record the drill pipe and casing pressures. Determine the pump pressure at the kill speed.

Important: If in doubt at any time during the entire procedure, shut in the well, read and record the shut-in drill pipe pressure and the shut-in casing pressure, and proceed accordingly.

It is not uncommon for the surface pressures to fluctuate slightly due to temperature, gas migration, or gauge problems. Therefore, it is important to record the surface pressures immediately prior to commencing pumping operations.

The second statement is extremely important to keep in mind. When in doubt, shut in the well! It seems that the prevailing impulse is to continue circulating regardless of the consequences. If the condition of the well has deteriorated since it was shut in, it deteriorated during the pumping phase. When in doubt, shut in the well, read the surface pressures, compare with the original pressures, and evaluate the situation prior to further operations. If something is wrong with the displacement procedure being used, the situation is less likely to deteriorate while shut in and more likely to continue to deteriorate if pumping is continued.

Step 3

Bring the pump to a kill speed, keeping the casing pressure constant. This step should require less than 5 min.

As previously stated, bringing the pump to speed is one of the most difficult problems in any well control procedure. Experience has shown that the most practical approach is to keep the casing pressure constant at the shut-in casing pressure while bringing the pump to speed. The initial gas expansion is negligible over the allotted time of 5 min required to bring the pump to speed.

It is not important that the initial volume rate of flow be exact. Any rate within 10% of the kill rate is satisfactory. This procedure will establish the correct drill pipe pressure to be used to displace the kick. Fig. 2.6 can be used to verify the drill pipe pressure being used.

Practically, the rate can be lowered or raised at any time during the displacement procedure. Simply read and record the circulating casing pressure and hold that casing pressure constant while adjusting the pumping rate and establishing a new drill pipe pressure. No more than 1–2 min can be allowed for changing the rate when the gas influx is near the surface because the expansion near the surface is quite rapid.

Step 4

Once the pump is at a satisfactory kill speed, read and record the drill pipe pressure. Displace the influx, keeping the recorded drill pipe pressure constant.

Actually, all steps must be considered together and are integral to each other. The correct drill pipe pressure used to circulate out the influx will be that drill pipe pressure established by Step 4. The pump rates and pressures established in Step 1 are to be used as a confirming reference only once the operation has commenced. Consideration of the U-tube model in Fig. 2.5 clearly illustrates that, by holding the casing pressure constant at the shut-in casing pressure while bringing the pump to speed, the appropriate drill pipe pressure will be established for the selected rate.

All adjustments to the circulating operation must be performed considering the casing annulus pressure. In adjusting the pressure on the circulating system, the drill pipe pressure response must be considered secondarily because there is significant lag time between any choke operation and the response on the drill pipe pressure gauge. This lag time is caused by the time required for the pressure transient to travel from the choke to the drill pipe pressure gauge.

Pressure responses travel at the speed of sound in the medium. The speed of sound is 1088 ft/s in air and about 4800 ft/s in most water-based drilling muds. Therefore, in a 10,000 ft well, a pressure transient caused by opening or closing the choke would not be reflected on the standpipe pressure gauge until 4 s later. Utilizing only the drill pipe pressure and the choke usually results in large cyclical variations that cause additional influxes or unacceptable pressures at the casing shoe.

Step 5

Once the influx has been displaced, record the casing pressure and compare with the original shut-in drill pipe pressure recorded in Step 1. It is important to note that, if the influx has been completely displaced, the casing pressure should be equal to the original shut-in drill pipe pressure.

Consider the U-tube model presented in Fig. 2.7 and compare it with the U-tube model illustrated in Fig. 2.5. If the influx has been

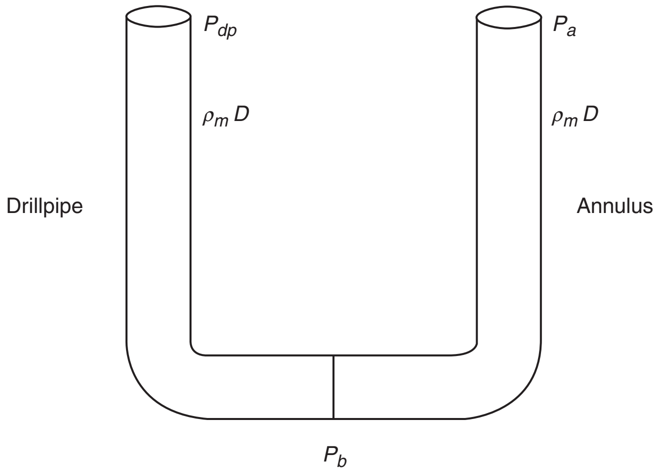

Fig. 2.7 Influx displaced—the U-tube model.

properly and completely displaced, the conditions in the annulus side of Fig. 2.7 are exactly the same as the conditions in the drill pipe side of Fig. 2.5. If the frictional pressure losses in the annulus are negligible, the conditions in the annulus side of Fig. 2.7 will be approximately the same as the drill pipe side of Fig. 2.5. Therefore, once the influx is displaced, the circulating annulus pressure should be equal to the initial shut-in drill pipe pressure.

Step 6

If the casing pressure is equal to the original shut-in drill pipe pressure recorded in Step 1, shut in the well by keeping the casing pressure constant while slowing the pumps. If the casing pressure is greater than the original shut-in drill pipe pressure, continue circulating for an additional circulation, keeping the drill pipe pressure constant, and then shut in the well, keeping the casing pressure constant while slowing the pumps.

Step 7

Read, record, and compare the shut-in drill pipe and casing pressures. If the well has been properly displaced, the shut-in drill pipe pressure should be equal to the shut-in casing pressure.

Again consider Fig. 2.7. Assuming that the influx has been completely displaced, conditions in both sides of the U-tube model are exactly the same. Therefore, the pressures at the surface on both the drill pipe and casing should be exactly the same.

Often, pressure is trapped in the system during the displacement procedure. If the drill pipe pressure and casing pressure are equal after displacing the influx but greater than the original shut-in drill pipe pressure or that drill pipe pressure recorded in Step 2, the difference between the two values is probably due to trapped pressure.

If the surface pressures recorded after displacement are equal but greater than the initial shut-in drill pipe pressure and formation influx is still present in the annulus, this discussion is not valid. These conditions are discussed in the special problems in Chapter Four.

Step 8

If the shut-in casing pressure is greater than the shut-in drill pipe pressure, repeat Steps 2–7.

If, after displacing the initial influx, the shut-in casing pressure is greater than the shut-in drill pipe pressure, it is probable that an additional influx was permitted at some point during the displacement procedure. Therefore, it will be necessary to displace that second influx.

Step 9

If the shut-in drill pipe pressure is equal to the shut-in casing pressure, determine the density of the kill-weight mud, ρ_1, using Eq. (2.9) (Note that no "safety factor" is recommended or included):

$$\rho_1 = \frac{\rho_m D + P_{dp}}{0.052D}$$

Safety factors are discussed in detail in Chapter Four.

Step 10

Raise the mud weight in the suction pit to the density determined in Step 9.

Step 11

Determine the number of STB by dividing the capacity of the drill string in barrels by the capacity of the pump in barrels per stroke according to Eq. (2.10):

$$\mathrm{STB} = \frac{C_{dp} l_{dp} + C_{hw} l_{hw} + C_{dc} l_{dc}}{C_p}$$

Sections or different weights of drill pipe, drill collars, or heavy-weight drill pipe may be added or deleted from Eq. (2.10) simply by adding to or subtracting from the numerator of Eq. (2.10) the product of the capacity and the length of the section.

Step 12

Bring the pump to speed, keeping the casing pressure constant.

Step 13

Displace the kill-weight mud to the bit, keeping the casing pressure constant.

Warning: Once the pump rate has been established, no further adjustments to the choke should be required. The casing pressure should remain constant at the initial shut-in drill pipe pressure. If the casing pressure begins to rise, the procedure should be terminated, and the well shut in.

It is vital to understand Step 13. Again, consider the U-tube model in Fig. 2.7. While the kill-weight mud is being displaced to the bit on the drill pipe side, under dynamic conditions no changes are occurring in any of the conditions on the annulus side. Therefore, once the pump rate has been established, the casing pressure should not change and it should not be necessary to adjust the choke to maintain the constant drill pipe pressure.

If the casing pressure does begin to increase, with everything else being constant, in all probability, there is some gas in the annulus. If there is gas in the annulus, this procedure must be terminated. Since the density of the mud at the surface has been increased to the kill, the proper procedure under these conditions would be the wait-and-weight method, which is further described in the section entitled "The Wait-and-Weight Method." The wait-and-weight method would be used to circulate the gas in the annulus to the surface and control the well.

Step 14

After pumping the number of strokes required for the kill mud to reach the bit, read and record the drill pipe pressure.

Step 15

Displace the kill-weight mud to the surface, keeping the drill pipe pressure constant.

Referring to Fig. 2.7, once kill-weight mud has reached the bit and the displacement of the annulus begins, conditions on the drill pipe side of the U-tube model are constant and do not change. Therefore, the kill-weight mud can be displaced to the surface by keeping the drill pipe pressure constant. Some change in casing pressure and adjustment in the choke size can be expected during this phase. If the procedure has been executed properly, the choke size will be increased to maintain the constant drill pipe pressure, and the casing pressure will decline to 0 when the kill-weight mud reaches the surface.

Step 16

With kill-weight mud to the surface, shut in the well by keeping the casing pressure constant while slowing the pumps.

Step 17

Read and record the shut-in drill pipe pressure and the shut-in casing pressure. Both pressures should be zero.

Step 18

Open the well and check for flow.

Step 19

If the well is flowing, repeat the procedure.

Step 20

If no flow is observed, raise the mud weight to include the desired trip margin and circulate until the desired mud weight is attained throughout the system.

The driller's method is illustrated in Example 2.3:

Example 2.3

Given:

Wellbore schematic = Fig. 2.8

Well depth, $D = 10{,}000$ ft.

Hole size, $D_h = 7\frac{7}{8}$ in.

Drill pipe size, $D_p = 4\frac{1}{2}$ in.

$8\frac{5}{8}$ in. surface casing = 2000 ft

Casing internal diameter, $D_{ci} = 8.017$ in

Fracture gradient, $F_g = 0.76$ psi/ft

Mud weight, $\rho = 9.6$ ppg

Mud gradient, $\rho_m = 0.50$ psi/ft

A kick is taken with the drill string on bottom and

Shut-in drill pipe pressure, $P_{dp} = 200$ psi

Shut-in annulus pressure, $P_a = 300$ psi

Pit-level increase = 10 bbl

Normal circulation rate = 6 bpm at 60 spm

Kill rate = 3 bpm at 30 spm

Circulating pressure at kill rate, $P_{ks} = 500$ psi

Pump capacity, $C_p = 0.1$ bbl/stk

Example 2.3—cont'd

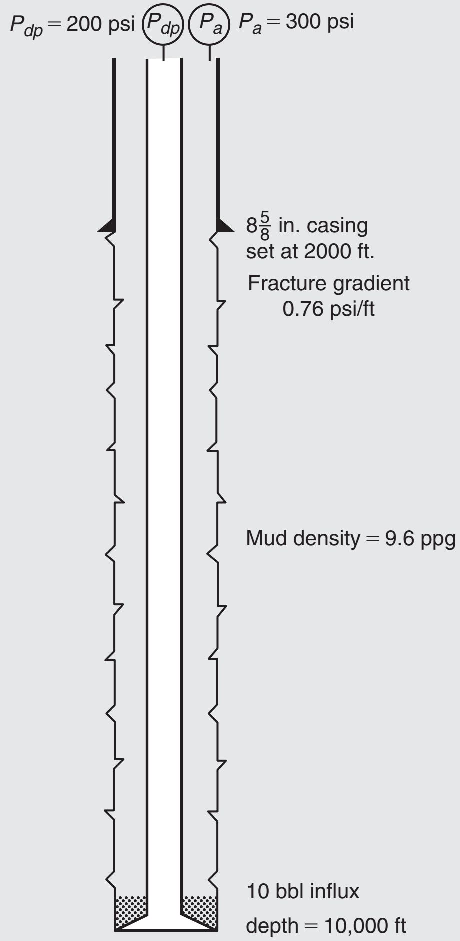

Fig. 2.8 Wellbore schematic-with kick.

Capacity of the

Drill pipe, $C_{dpi} = 0.0142$ bbl/ft

Drill pipe casing annulus, $C_{dpca} = 0.0428$ bbl/ft

Drill pipe hole annulus, $C_{dpha} = 0.0406$ bbl/ft

Kick tolerance diagram—Fig. 2.3

Note: For simplicity in calculation and illustration, no drill collars are assumed. The inclusion of drill collars adds only an intermediate calculation.

Required:

1. Determine if classical well control procedures are applicable.
2. Describe the kill procedure using the driller's method.

Example 2.3—cont'd

Solution:

1. Consider Fig. 2.3. Note that the point established by 200 psi shut-in drill pipe pressure and a 10 bbl influx is within the kick tolerance envelope. Therefore, classical pressure control procedures are applicable.
2. Establish pressure versus volume diagram (Fig. 2.6).
3. Record the shut-in drill pipe pressure and shut-in casing pressure.

$$P_{dp} = 200\,\text{psi}$$
$$P_a = 300\,\text{psi}$$

4. Establish the pumping pressure at the kill rate of 30 spm using Eq. (2.8):

$$P_c = P_{ks} + P_{dp}$$
$$P_c = 500 + 200$$
$$P_c = 700\,\text{psi}$$

5. Bring the pump to 30 spm, maintaining 300 psi on the casing annulus.
6. Read and record the drill pipe pressure equal to 700 psi. Confirm the drill pipe pressure using Fig. 2.6.
7. Displace the annulus and all gas, which has entered the wellbore, keeping the drill pipe pressure constant at 700 psi.
8. Read and record the drill pipe pressure equal to 700 psi and casing pressure equal to 200 psi.
9. Shut in the well, keeping the casing pressure constant at 200 psi. Allow the well to stabilize.
10. Determine that all gas is out of the mud.

$$P_a = P_{dp} = 200\,\text{psi}.$$

11. Determine the kill weight, ρ_1, using Eq. (2.9):

$$\rho_1 = \frac{\rho_m D + P_{dp}}{0.052D}$$
$$\rho_1 = \frac{0.5(10,000) + 200}{0.052(10,000)}$$
$$\rho_1 = 10\,\text{ppg}$$

12. Determine the STB using Eq. (2.10):

$$STB = \frac{C_{dp}l_{dp} + C_{hw}l_{hw} + C_{dc}l_{dc}}{C_p}$$
$$STB = \frac{(0.0142)(10,000)}{0.1}$$
$$STB = 1420\,\text{stk}$$

Continued

Example 2.3—cont'd

13. Raise the mud weight at the surface to 10 ppg.
14. Bring the pump to 30 spm, keeping the casing pressure constant at 200 psi.
15. Displace the 10 ppg mud to the bit with 1420 stk, keeping the annulus pressure, P_a, constant at 200 psi. The choke size must not change.
16. At 1420 stk, observe and record the circulating pressure on the drill pipe. Assume that the observed pressure on the drill pipe is 513 psi.
17. Circulate the 10 ppg mud to the surface, keeping the drill pipe pressure constant at 513 psi.
18. Shut in and check $P_a = P_{dp} = 0$ psi. The well is dead.
19. Circulate and raise the mud weight to some acceptable trip margin, generally between 150 and 500 psi above the formation pressure, P_b, or 10.3–11.0 ppg.
20. Continue drilling ahead.

The Wait and Weight Method

The alternative classical method is commonly known as the wait-and-weight method. As the name implies, the well is shut in, while the mud density is increased to the kill weight as determined by Eq. (2.9). Therefore, the primary difference is operational in that the kill-weight mud, ρ_1, is pumped, while the gas is being displaced. The result is that the well is killed in one circulation with the wait-and-weight method, whereas, with the driller's method, two circulations are required.

In the early days of pressure control, the time required to increase the density of the mud in the surface system to the kill weight was significant. During that time, it was not uncommon for the gas to migrate or for the drill pipe to become stuck. However, modern mud-mixing systems have eliminated the time factor from most operations in that most systems can raise the density of the surface system as fast as the mud is pumped. There are other important comparisons, which will be presented after the wait-and-weight method is presented, illustrated, and discussed.

While each step will be subsequently discussed in detail, the displacement procedure for the wait-and-weight method is as follows:

Step 1

On each tour, read and record the standpipe pressure at several rates in strokes per minute (spm), including the anticipated kill rate for each pump.

Step 2

Prior to pumping, read and record the drill pipe and casing pressures. Determine the anticipated pump pressure at the kill rate using Eq. (2.8):

$$P_c = P_{ks} + P_{dp}$$

Step 3

Determine the density of the kill-weight mud, ρ_1, using Eq. (2.9) (Note that no "safety factor" is recommended or included):

$$\rho_1 = \frac{\rho_m D + P_{dp}}{0.052D}$$

Step 4

Determine the number of STB by dividing the capacity of the drill string in barrels by the capacity of the pump in barrels per stroke according to Eq. (2.10):

$$STB = \frac{C_{dp} l_{dp} + C_{hw} l_{hw} + C_{dc} l_{dc}}{C_p}$$

Step 5

Determine the new circulating pressure, P_{cn}, at the kill rate with the kill-weight mud at the bit utilizing Eq. (2.11):

$$P_{cn} = P_{dp} - 0.052(\rho_1 - \rho)D + \left(\frac{\rho_1}{\rho}\right) P_{ks} \quad (2.11)$$

where

ρ_1 = density of the kill-weight mud, ppg
ρ = density of the original mud, ppg
P_{ks} = original circulating pressure at kill rate, psi
P_{dp} = shut-in drill pipe pressure, psi
D = well depth, ft

Step 6

For a complex drill string configuration, determine and graph the pumping schedule for reducing the initial circulating pressure, P_c, determined in Step 2 to the final circulating pressure, P_{cn}, determined in Step 5. Using Eqs. (2.12a–2.12d), (2.13a–2.13d), calculate Table 2.1 and create the corresponding graph.

Note: A "section" of drill string is the length where all the diameters remain the same. A new section would start any time the hole size or pipe diameter changes. As long as the diameters remain the same, it is one section. Therefore, each section has one annular capacity. The calculations begin from the surface.

For example, if the hole size does not change and the string consists of two weights of drill pipe, heavyweight drill pipe, and drill collars, four calculations would be required.

The table would look like the following:

$$\text{STKS}\ \ 1 = \frac{C_{ds1} l_{ds1}}{C_p} \tag{2.12a}$$

$$\text{STKS}\ \ 2 = \frac{C_{ds1} l_{ds1} + C_{ds2} l_{ds2}}{C_p} \tag{2.12b}$$

$$\text{STKS}\ \ 3 = \frac{C_{ds1} l_{ds1} + C_{ds2} l_{ds2} + C_{ds3} l_{ds3}}{C_p} \tag{2.12c}$$

$$\text{STB} = \frac{C_{ds1} l_{ds1} + C_{ds2} l_{ds2} + C_{ds3} l_{ds3} + \ldots + C_{dc} l_{dc}}{C_p} \tag{2.12d}$$

$$P_1 = P_c - 0.052(\rho_1 - \rho)(l_{ds1}) + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right)\left(\frac{\text{STKS}\ \ 1}{\text{STB}}\right) \tag{2.13a}$$

$$P_2 = P_c - 0.052(\rho_1 - \rho)(l_{ds1} + l_{ds2}) + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right)\left(\frac{\text{STKS}\ \ 2}{\text{STB}}\right) \tag{2.13b}$$

$$P_3 = P_c - 0.052(\rho_1 - \rho)(l_{ds1} + l_{ds2} + l_{ds3}) + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right)\left(\frac{\text{STKS}\ \ 3}{\text{STB}}\right) \tag{2.13c}$$

Table 2.1 Drill pipe pressure schedule

Strokes	**Pressure**
0	700
STKS 1	P_1
STKS 2	P_2
STKS 3	P_3
…	…
STB	P_{cn}

$$P_{cn} = P_{dp} - 0.052(\rho_1 - \rho) \times (l_{ds1} + l_{ds2} + l_{ds3} + \ldots + l_{dc}) + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right) \tag{2.13d}$$

where

STKS 1 = strokes to end of section 1 of drill string

STKS 2 = strokes to end of section 2 of drill string

STKS 3 = strokes to end of section 3 of drill string

STB = strokes to the bit as determined in Step 4

where

ρ_1 = density of kill-weight mud, ppg

ρ = density of original mud, ppg

l_{dc} = length of section of drill collars, ft

$l_{ds1,2,3}$ = length of section of drill string, ft

C_{dc} = capacity of section of drill collars, bbl/ft

$C_{ds1,2,3}$ = capacity of section of drill string, bbl/ft

$P_{1,2,3}$ = circulating pressure with kill-weight mud to the end of sections 1, 2, and 3, psi

P_{dp} = shut-in drill pipe pressure, psi

P_{ks} = circulating pressure at kill speed determined in Step 1, psi

C_p = pump capacity, bbl/stk

P_{cn} = new circulating pressure, psi

P_c = initial displacement pressure determined in Step 2 using Eq. (2.8), psi

For a drill string composed of only one weight of drill pipe and one string of heavyweight drill pipe or drill collars, the pumping schedule can be determined using Eq. (2.14):

$$\frac{\text{STKS}}{25\,\text{psi}} = \frac{25(\text{STB})}{P_c - P_{cn}} \tag{2.14}$$

Step 7

Raise the density of the mud in the suction pit to the kill weight determined in Step 3.

Step 8

Bring the pump to a kill speed, keeping the casing pressure constant at the shut-in casing pressure. This step should require less than 5 min.

Step 9

Once the pump is at a satisfactory kill speed, read and record the drill pipe pressure. Adjust the pumping schedule accordingly. Verify the drill pipe pressure using the diagram established in Step 1. Displace the kill-weight mud to the bit pursuant to the pumping schedule established in Step 6 as revised in this step.

Step 10

Displace the kill-weight mud to the surface, keeping the drill pipe pressure constant.

Step 11

Shut in the well, keeping the casing pressure constant, and observe that the drill pipe pressure and the casing pressure are 0 and the well is dead.

Step 12

If the surface pressures are not 0 and the well is not dead, continue to circulate, keeping the drill pipe pressure constant.

Step 13

Once the well is dead, raise the mud weight in the suction pit to provide the desired trip margin.

Step 14

Drill ahead.

Discussion of each step in detail follows:

Step 1

On each tour, read and record the standpipe pressure at several rates in strokes per minute (spm), including the anticipated kill rate for each pump.

This is the same discussion as presented after Step 1 of the driller's method. Experience has shown that one of the most difficult aspects of any kill procedure is bringing the pump to speed without permitting an additional influx or fracturing the casing shoe. This problem is compounded by attempts to achieve a precise kill rate. There is nothing magic about the kill rate used to circulate out a kick.

In the early days of pressure control, surface facilities were inadequate to bring an influx to the surface at a high pump speed. Therefore, one-half normal speed became the arbitrary rate of choice for circulating the influx to the surface. However, if only one rate such as the one-half speed is acceptable, problems can arise when the pump speed is slightly less or slightly more than the precise one-half speed. The reason for the potential problem is that the circulating pressure at rates other than the kill rate is unknown. Refer to further discussion after Step 4.

The best procedure is to record and graph several flow rates and corresponding pump pressures as illustrated in Fig. 2.6. It is assumed in Examples 2.3 and 2.4 that the kill speed used is 30 stk/min.

However, the actual pump speed used need not be exactly 30 stk/min. The drill pipe pressure corresponding to the actual pump speed being used could be verified using Fig. 2.6.

Step 2

Prior to pumping, read and record the drill pipe and casing pressures. Determine the anticipated pump pressure at the kill rate using Eq. (2.8):

$$P_c = P_{ks} + P_{dp}$$

This is the same discussion as presented after Step 2 of the driller's method. It is not uncommon for the surface pressures to fluctuate slightly due to temperature, migration, or gauge problems. Therefore, it is important to record the surface pressures immediately prior to commencing pumping operations.

When in doubt, shut in the well! It seems that the prevailing impulse is to continue circulating regardless of the consequences. If the condition of the well has deteriorated since it was shut in, it deteriorated during the pumping phase. When in doubt, shut in the well, read the surface pressures, compare with the original pressures, and evaluate the situation prior to further operations. If something is wrong with the displacement procedure being used, the situation is less likely to deteriorate while shut in and more likely to continue to deteriorate if pumping is continued.

Step 3

Determine the density of the kill-weight mud, ρ_1, using Eq. (2.9) (Note that no "safety factor" is recommended or included):

$$\rho_1 = \frac{\rho_m D + P_{dp}}{0.052D}$$

Safety factors are discussed in Chapter Four.

Step 4

Determine the number of STB by dividing the capacity of the drill string in barrels by the capacity of the pump in barrels per stroke according to Eq. (2.10):

$$\text{STB} = \frac{C_{dp} l_{dp} + C_{hw} l_{hw} + C_{dc} l_{dc}}{C_p}$$

Sections of different weights of drill pipe, drill collars, or heavy-weight drill pipe may be added or deleted from Eq. (2.10) simply by adding to or subtracting from the numerator of Eq. (2.10) the product of the capacity and the length of the section.

Step 5

Determine the new circulating pressure, P_{cn}, at the kill rate with the kill-weight mud utilizing Eq. (2.11):

$$P_{cn} = P_{dp} - 0.052(\rho_1 - \rho)D + \left(\frac{\rho_1}{\rho}\right)P_{ks}$$

The new circulating pressure with the kill-weight mud will be slightly greater than the recorded circulating pressure at the kill speed since the frictional pressure losses are a function of the density of the mud. In Eq. (2.11) the frictional pressure loss is considered a direct function of the density. In reality, the frictional pressure loss is a function of the density to the 0.8 power. However, the difference is insignificant.

Step 6

For a complex drill string configuration, determine and graph the pumping schedule for reducing the initial circulating pressure, P_c, determined in Step 2 to the final circulating pressure, P_{cn}, determined in Step 5. Using Eqs (2.12a–2.12d), (2.13a–2.13d), calculate Table 2.1 and create the corresponding graph.

Note: A "section" of drill string is the length where all the diameters remain the same. A new section would start any time the hole size or pipe diameter changed. As long as the diameters remain the same, it is one section. Therefore, each section has one annular capacity. The calculations begin from the surface. For example, if the hole size does not change and the string consists of two weights of drill pipe, heavyweight drill pipe, and drill collars, four calculations would be required.

Determining this pump schedule is a most critical phase. Use of these equations is illustrated in Example 2.4. Basically, the circulating drill pipe pressure is reduced systematically to offset the increase in hydrostatic introduced by the kill-weight mud and ultimately to keep the bottom-hole pressure constant.

The systematic reduction in drill pipe pressure must be attained by reducing the casing pressure by the scheduled amount and waiting 4–5 s for the pressure transient to reach the drill pipe pressure gauge. Efforts to control the drill pipe pressure directly by manipulating the choke are usually unsuccessful due to the time lag.

The key to success is to observe several gauges at the same time. The sequence is usually to observe the choke position, the casing pressure, and drill pipe pressure. Then concentrate on the choke position indicator while slightly opening the choke. Next, check the choke pressure gauge for the reduction in choke pressure. Continue that sequence until the designated amount of pressure has been bled from the annulus pressure gauge.

Finally, wait 10 s and read the result on the drill pipe pressure gauge. Repeat the process until the drill pipe pressure has been adjusted appropriately.

Step 7

Raise the density of the mud in the suction pit to the kill weight determined in Step 3.

Step 8

Bring the pump to a kill speed, keeping the casing pressure constant at the shut-in casing pressure. This step should require less than 5 min.

Step 9

Once the pump is at a satisfactory kill speed, read and record the drill pipe pressure. Adjust the pumping schedule accordingly. Verify the drill pipe pressure using the diagram established in Step 1. Displace the kill-weight mud to the bit pursuant to the pumping schedule established in Step 6 as revised in this step.

As discussed in the driller's method, the actual kill speed used is not critical. Once the actual kill speed is established at a constant casing pressure equal to the shut-in casing pressure, the drill pipe pressure read is correct. The pumping schedule must be adjusted to reflect a pump speed different from the pump speed used to construct the table and graph.

The adjustment of the table is accomplished by reducing arithmetically the initial drill pipe pressure by the shut-in drill pipe pressure and remaking the appropriate calculations. The graph is more easily adjusted. The circulating drill pipe pressure marks the beginning point. Using that point, a line is drawn, which is parallel to the line drawn in Step 6. The new line becomes the correct pumping schedule. The graph of pump pressure versus volume constructed in Step 1 is used to confirm the calculations.

If doubt arises during the pumping procedure, the well should be shut in by keeping the casing pressure constant while slowing the pump. The shut-in drill pipe pressure, shut-in casing pressure, and volume pumped should be used to evaluate the situation. The pumping procedure can be continued by bringing the pump to speed keeping the casing pressure constant, reading the drill pipe pressure, plotting the point on the pumping schedule graph, and establishing a new line parallel to the original. These points are clarified in Examples 2.3 and 2.4.

Keeping the casing pressure constant in order to establish the pump speed and correct circulating drill pipe pressure is an acceptable procedure provided that the time period is short, and the influx is not near the surface. The time period should never be more than 5 min. If the influx is near the surface, the casing pressures will be changing very rapidly. In that case, the time period should be 1–2 min.

Step 10

Displace the kill-weight mud to the surface, keeping the drill pipe pressure constant.

Step 11

Shut in the well, keeping the casing pressure constant, and observe that the drill pipe pressure and the casing pressure are zero and the well is dead.

Step 12

If the surface pressures are not zero and the well is not dead, continue to circulate, keeping the drill pipe pressure constant.

Step 13

Once the well is dead, raise the mud weight in the suction pit to provide the desired trip margin.

Step 14

Drill ahead.

The wait-and-weight method is illustrated in Example 2.4:

Example 2.4

Given:

Wellbore schematic—Fig. 2.8

Kick tolerance diagram—Fig. 2.3

Well depth, $D = 10{,}000$ ft

Hole size, $D_h = 7\frac{7}{8}$in.

Drill pipe size, $D_p = 4\frac{1}{2}$in.

$8\frac{5}{8}$in. surface casing $= 2000$ ft

Casing internal diameter, $D_{ci} = 8.017$ in

Fracture gradient, $F_g = 0.76$ psi/ft

Mud weight, $\rho = 9.6$ ppg

Example 2.4—cont'd

Mud gradient, $\rho_m = 0.50$ psi/ft

A kick is taken with the drill string on bottom and

Shut-in drill pipe pressure, $P_{dp} = 200$ psi

Shut-in annulus pressure, $P_a = 300$ psi

Pit-level increase = 10 bbl

Normal circulation rate = 6 bpm at 60 spm

Kill rate = 3 bpm at 30 spm

Circulating pressure at kill rate, $P_{ks} = 500$ psi

Pump capacity, $C_p = 0.1$ bbl/stk

Capacity of the

Drill pipe, $C_{dpi} = 0.0142$ bbl/ft

Drill pipe casing annulus, $C_{dpca} = 0.0428$ bbl/ft

Drill pipe hole annulus, $C_{dpha} = 0.0406$ bbl/ft

Note: For simplicity in calculation and illustration, no drill collars are assumed. The inclusion of drill collars adds only an intermediate calculation.

Required:

1. Determine if classical well control procedures are applicable.
2. Describe the kill procedure using the wait-and-weight method.

Solution:

1. In Fig. 2.3, note that the point defined by a shut-in drill pipe pressure of 200 psi and an influx of 10 bbl is within the kick tolerance envelope. The kick tolerance diagram such as Fig. 2.3 should be developed assuming that the driller's method will be used to circulate out the influx, which is a worst-case scenario.
2. Establish pressure versus volume diagram using Fig. 2.6.
3. Record the shut-in drill pipe pressure and shut-in casing pressure.

$$P_{dp} = 200\,\text{psi}$$
$$P_a = 300\,\text{psi}$$

4. Establish the pumping pressure at the kill rate of 30 spm using Eq. (2.8):

$$P_c = P_{ks} + P_{dp}$$
$$P_c = 500 + 200$$
$$P_c = 700\,\text{psi}$$

5. Determine the kill weight, ρ_1, using Eq. (2.9):

$$\rho_1 = \frac{\rho_m D + P_{dp}}{0.052D}$$
$$\rho_1 = \frac{0.5(10,000) + 200}{0.052(10,000)}$$
$$\rho_1 = 10\,\text{ppg}$$

Continued

Example 2.4—cont'd

6. Determine the STB using Eq. (2.10):

$$STB = \frac{C_{dp} l_{dp} + C_{hw} l_{hw} + C_{dc} l_{dc}}{C_p}$$

$$STB = \frac{(0.0142)(10,000)}{0.1}$$

$$STB = 1420\,\text{stk}$$

7. Determine the new circulating pressure, P_{cn}, at the kill rate with the kill-weight mud utilizing Eq. (2.11):

$$P_{cn} = P_{dp} - 0.052(\rho_1 - \rho)D + \left(\frac{\rho_1}{\rho}\right) P_{ks}$$

$$P_{cn} = 200 - 0.052(10 - 9.6)(10,000) + \left(\frac{10}{9.6}\right) 500$$

$$P_{cn} = 513\,\text{psi}$$

8. Determine the pumping schedule for a simple drill string pursuant to Eq. (2.14): (Table 2.2)

Table 2.2 Drill pipe pressure schedule, Example 2.4

Strokes	Pressure
0	700
190	675
380	650
570	625
760	600
950	575
1140	550
1330	525
1420	513
1600	513

$$\frac{STKS}{25\,\text{psi}} = \frac{25(STB)}{P_c - P_{cn}}$$

$$\frac{STKS}{25\,\text{psi}} = \frac{25(1420)}{700 - 513}$$

$$\frac{STKS}{25\,\text{psi}} = 190\,\text{stk}$$

Example 2.4—cont'd

9. Construct Fig. 2.9—graph of pump schedule.

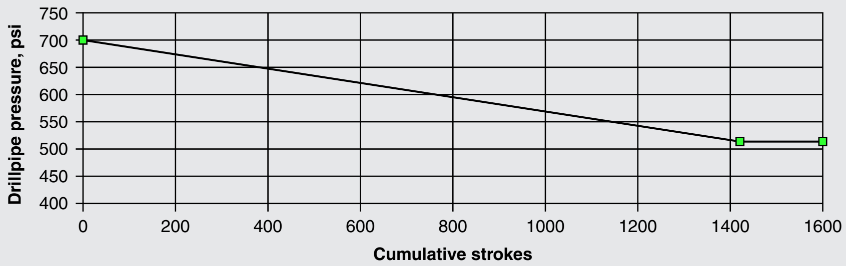

Fig. 2.9 Drillpipe pressure schedule. Wait-and-weight method, Example 2.4.

10. Bring pump to 30 spm, keeping the casing pressure constant at 300 psi.

11. Displace the kill-weight mud to the bit (1420 stk) according to the pump schedule developed in Steps 7 and 8.

After 190 stk, reduce the casing pressure observed at that moment by 25 psi. After 10 s, observe that the drill pipe pressure has dropped to 675 psi. After 380 stk, reduce the casing pressure observed at that moment by 25 psi. After 10 s, observe that the drill pipe pressure has dropped to 650 psi. Continue in this manner until the kill-weight mud is at the bit and the drill pipe pressure is 513 psi.

12. With the kill-weight mud to the bit after 1420 stk, read and record the drill pipe pressure equal to 513 psi.

13. Displace the kill-weight mud to the surface, keeping the drill pipe pressure constant at 513 psi.

14. Shut in the well, keeping the casing pressure constant, and observe that the drill pipe and pressure are zero.

15. Check for flow.

16. Once the well is confirmed dead, raise the mud weight to provide the desired trip margin and drill ahead.

Obviously, the most potentially confusing aspect of the wait-and-weight method is the development and application of the pumping schedule used to circulate the kill-weight mud properly to the bit while maintaining a constant bottom-hole pressure. The development and application of the pump schedule is further illustrated in Example 2.5 to provide additional clarity:

Example 2.5

Given:

Example 2.4

Required:

1. Assume that the kill speed established in Step 9 of Example 2.4 was actually 20 spm instead of the anticipated 30 spm. Determine the effect on the pump schedule and demonstrate the application of Fig. 2.9.
2. Assume that the drill string is complex and composed of 4000 ft of 5 in 19.5 lb/ft, 4000 ft of $4\frac{1}{2}$in. 16.6 lb/ft, 1000 ft of $4\frac{1}{2}$in. heavyweight drill pipe, and 1000 ft of 6 in.-by-2 in. drill collars. Illustrate the effect of the complex string configuration on Fig. 2.9. Compare the pump schedule developed for the complex string with that obtained with the straight line simplification.

Solution:

1. Pursuant to Fig. 2.6, the surface pressure at a kill speed of 20 spm would be 240 psi. The initial displacement surface pressure would be given by Eq. 2.8 as follows:

$$P_c = P_{ks} + P_{dp}$$
$$P_c = 240 + 200$$
$$P_c = 440\,\text{psi}$$

Therefore, simply locate 440 psi on the y-axis of Fig. 2.9 and draw a line parallel to that originally drawn. The new line is the revised pumping schedule. This concept is illustrated as Fig. 2.10.

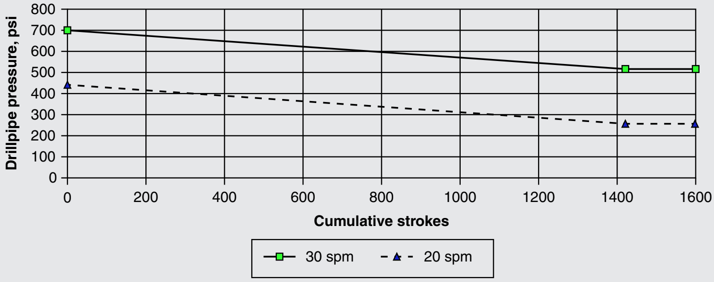

Fig. 2.10 Drillpipe pressure schedule—20 vs. 30 spm.

As an alternative, merely subtract 260 psi (700–440) from the values listed in Table 2.3 in Step 7.

Example 2.5—cont'd

Table 2.3 Drill pipe pressure schedule, Example 2.5

Strokes	Pressure
0	440
190	415
380	390
570	365
760	340
950	315
1140	290
1330	265
1420	253
1600	253

2. Eqs. (2.10), (2.12a–2.12d), (2.13a–2.13d) are used to graph the new pump schedule presented as Fig. 2.11:

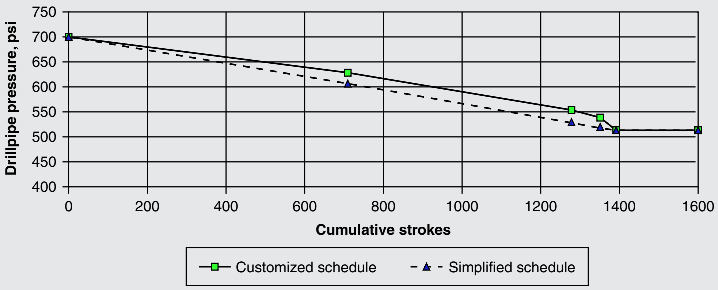

Fig. 2.11 Drillpipe pressure schedule. Custom vs. simplified pump schedule.

$$\text{STB} = \frac{C_{dp}l_{dp} + C_{hw}l_{hw} + C_{dc}l_{dc}}{C_p}$$

$$\text{STB} = \{(0.01776)(4000) + (0.01422)(4000)$$
$$+(0.00743)(1000)$$
$$+ (0.00389)(1000)\} \div 0.10$$

$$\text{STB} = 1392 \text{ stk}$$

The graph is determined from Eqs. (2.12a–2.12d), (2.13a–2.13d):

$$\text{STKS} \quad 1 = \frac{C_{ds1}l_{ds1}}{C_p}$$

$$\text{STKS} \quad 1 = \frac{(0.01776)(4000)}{0.1}$$

$$\text{STKS} \quad 1 = 710 \text{ stk}$$

Continued

Example 2.5—cont'd

$$\text{STKS}\quad 2 = \frac{C_{ds1} l_{ds1} + C_{ds2} l_{ds2}}{C_p}$$

$$\text{STKS}\quad 2 = \frac{(0.01776)(4000) + (0.01422)(4000)}{0.1}$$

$$\text{STKS}\quad 2 = 1279 \text{ stk}$$

$$\text{STKS}\quad 3 = \frac{C_{ds1} l_{ds1} + C_{ds2} l_{ds2} + C_{ds3} l_{ds3}}{C_p}$$

$$\begin{aligned}\text{STKS}\quad 3 &= \{(0.01776)(4000)\\ &\quad + (0.01422)(4000)\\ &\quad + (0.00743)(1000) \div 0.10\end{aligned}$$

$$\text{STKS}\quad 3 = 1353 \text{ stk}$$

Similarly, STKS 4 = 1392 stk

The circulating pressure at the surface at the end of each section of drill string is given by Eq. (2.13a–2.13d):

$$\begin{aligned}P_1 &= P_c - 0.052(\rho_1 - \rho)(l_{ds1})\\ &\quad + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right)\left(\frac{\text{STKS 1}}{\text{STB}}\right)\end{aligned}$$

$$\begin{aligned}P_1 &= 700 - 0.052(10 - 9.6)(4000)\\ &\quad + \left(\frac{(10)(500)}{(9.6)} - 500\right)\left(\frac{710}{1392}\right)\end{aligned}$$

$$P_1 = 627\,\text{psi}$$

$$\begin{aligned}P_2 &= P_c - 0.052(\rho_1 - \rho)(l_{ds1} + l_{ds2})\\ &\quad + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right)\left(\frac{\text{STKS 2}}{\text{STB}}\right)\end{aligned}$$

$$\begin{aligned}P_2 &= 700 - 0.052(10 - 9.6)(4000 + 4000)\\ &\quad + \left(\frac{(10)(500)}{(9.6)} - 500\right)\left(\frac{1279}{1392}\right)\end{aligned}$$

$$P_2 = 552\,\text{psi}$$

Example 2.5—cont'd

$$P_3 = P_c - 0.052(\rho_1 - \rho)(l_{ds1} + l_{ds2} + l_{ds3}) + \left(\frac{\rho_1 P_{ks}}{\rho} - P_{ks}\right)\left(\frac{\text{STKS }3}{\text{STB}}\right)$$

$$P_3 = 700 - 0.052(10 - 9.6) \times (4000 + 4000 + 1000) + \left(\frac{(10)(500)}{(9.6)} - 500\right)\left(\frac{1353}{1392}\right)$$

$$P_3 = 534\,\text{psi}$$

Adding the final section of drill collars to the above equation,

$$P_4 = 513\,\text{psi}$$

As illustrated in Fig. 2.10, changing the pump speed at which the kick is displaced merely moves the pump schedule to a parallel position on the graph. As illustrated in Fig. 2.11, the complex pump schedule is slightly more difficult to construct. The simplified straight line pump schedule will underbalance the well during the period that the kill-weight mud is being displaced to the bit. In this example, the underbalance is only as much as 25 psi.

In reality, in most cases, the annular frictional pressure losses, which are considered negligible in classical pressure control analysis, would more than compensate and an additional influx would not occur. However, that may not be the case in any specific instance, and an additional influx could occur. In most instances, the simplified pump schedule would suffice. In significantly complex drill strings, this comparison should be made.

SUMMARY

Well control procedures for kicks taken while drilling were developed more than 50 years ago and are classical applications of the application of the laws of chemistry and physics to drilling operations. However, it must be realized and understood that these procedures are based on mathematical models, and if the actual situation is not consistent with the model upon which the procedures were developed, the models are meaningless. Further, the kick tolerance envelope describes and defines the boundaries for the application of the classical procedures. If the actual situation is outside the kick tolerance envelope, the procedures are meaningless. If the actual situation is not consistent with the model upon which the procedures were developed, the models are meaningless.

The driller's method was the first and most popular displacement procedure. The crew proceeded immediately to displace the influx. The required calculations were not difficult. The calculations were made, the kill-weight mud was easily displaced, and the drilling operation was resumed. One disadvantage of the driller's method is that at least two circulations are required to control the well.

The wait-and-weight method is slightly more complicated but offers some distinct advantages. First, the well is killed in half the time. Modern mud-mixing facilities permit barite to be mixed at rates up to 600 sacks/h with dual mixing systems; therefore, time required to weight up the suction pit is minimized, and kill rate is not penalized. The wait-and-weight method results in kill mud reaching the well sooner, and that is always an advantage.

In addition, as discussed and illustrated in Chapter Four, the annulus pressures are lower when the wait-and-weight method is used. The primary disadvantage is the potential for errors and problems while displacing the kill-weight mud to the bit. With the driller's method, the procedure can be stopped and started easily. Stopping and starting when using the wait-and-weight method is not as easy, especially during the period when the kill-weight mud is being displaced to the bit. It is not uncommon for good drilling men to get confused during displacement using the wait-and-weight method.

In view of all considerations, the wait-and-weight method is generally preferred by most operators.

REFERENCE

[1] API RP 59. Recommended practice for well control operations. 2nd ed.; 2006. p. 49.

CHAPTER THREE

Pressure Control Procedures While Tripping

22 June
Trip out of the hole. Well began flowing. Trip in the hole with the bottomhole assembly. Gained 60 bbls. Circulated the hole. Pressure continued to increase. Shut in well with 3000 psi. Drillpipe started coming through the rotary table. Opened choke, closed pipe rams above tool joint, and closed choke. Total gain was 140 barrels. Attempt to close safety valve without success. Open choke, close safety valve, close choke. Had 200 barrel total gain. Rigged up snubbing unit.

14 July
Began snubbing in the hole.

15 July
Continued snubbing to 4122 ft. Circulated 18.5 ppg mud. Surface pressure is 3700 psi.

16 July
Snubbed to 8870 ft. Began to circulate 18.5 ppg mud. Surface pressure increased to 5300 psi on casing. Mud in is 540 bbls vs. mud out of 780 bbls. Increased pump rate from 3 to 6 bpm. Drillpipe pressure increased to 6700 psi. Hammer union on rig floor washed out. Unable to close safety valves on rig floor due to excessive pressure and flow. Hydrogen sulfide monitors sounded. Ignited rig with flare gun.

The drilling report above is a good illustration of a disaster resulting from complications during tripping operations at a well that was under control only a few hours prior to the trip. It must be reasoned that any well that is tripped is under control when the bit leaves the bottom. Therefore, operations subsequent to the beginning of the trip precipitate the well control problem. As is often the case, due to operations subsequent to the time that a well control problem was detected, the condition of the well

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deteriorated and the well control problem became progressively more complicated.

The reason for this familiar unfortunate chain of events is that the industry has been and still is inconsistent under these circumstances. A recent survey of the major well control schools revealed substantial inconsistencies under the same given circumstances.

Actually, classical pressure control procedures apply only to problems that occur during drilling operations. Unfortunately, there is no widely accepted procedure to be followed when a kick occurs during a trip. Further, procedures and instructions that apply to problems during drilling are routinely posted on the rig floor. However, just as routinely, there are often no posted instructions that apply to procedures to be followed if the kick occurs during a trip. A federal court in Pecos, Texas, found a major oil company grossly negligent because procedures for problems occurring while drilling were posted and procedures for problems occurring while tripping were not. One purpose of this chapter is to suggest that classical trip procedures be adopted, taught, and posted.

CAUSES OF KICKS WHILE TRIPPING

Any well control problem that occurs during a trip is generally the result of a failure on the part of the rig crew to keep the hole full or the failure of the crew to recognize that the hole is not filling properly. The problem of keeping the hole full of fluid has been emphasized for many years. Pressure control problems and blowouts associated with trips continue to be a major occurrence. A lack of training and understanding contributes to these circumstances.

Classical pressure control procedures apply to drilling operations, not to tripping operations. All of the modeling and technology used in pressure control were developed based on a drilling model as opposed to a tripping model. Therefore, the technology that applies to pressure control problems that occur during drilling operations does not apply to pressure control problems that occur during tripping operations. As a result, when pressure control problems occur while tripping, drilling procedures are often applied, confusion reigns, and disaster results.

Trip Sheets and Filling Procedures

Prior to a trip, it is assumed that the well is under control and that a trip can be made safely if the full hydrostatic is maintained. Pressure control problems that occur during a trip are generally the result of swabbing or a simple failure to keep the hole full. In either case, recognition and prevention of the problem are much easier than the cure.

Accurate "trip sheets" must be kept whenever productive horizons have been penetrated or on the last trip before entering the transition zone or pay interval. The trip sheet is simply a record of the actual amount of mud used to keep the hole full while the drill string is being pulled, compared with the theoretical quantity required to replace the pipe that is being removed. Properly monitoring the tripping operation and utilizing the trip sheet will forewarn the crew of potential well control problems.

In order to fill and monitor the hole properly, the drill pipe must be slugged dry with a barite pill. Difficulty in keeping the pipe dry is not an acceptable excuse for failure to fill the hole properly. If the first pill fails to dry the drill pipe, pump a second pill heavier than the first. If the pipe is dry for some time and then pulls wet, pump another pill. A common question is "how frequently should the hole be filled?" The basic factors determining frequency are regulations, critical nature of the well, and the wellbore geometry.

Often, special field rules or regulatory commissions will specify the method to be used to maintain the hydrostatic in particular fields or areas. Certainly, these rules should be observed. It is acceptable to deviate from the established procedure with appropriate cause, or when the procedure to be used is widely accepted as being more definitive than that established by regulation. Certainly, the condition of some wells is more critical than that of others. The critical nature may be related to location, depth, pressure, hydrocarbon composition, or toxic nature of the formation fluids, to name a few.

To illustrate the significance of the wellbore geometry, consider Example 3.1:

Example 3.1

Given:

Well depth, $D = 10{,}000$ ft
Mud density, $\rho = 15$ ppg
Mud gradient, $\rho_m = 0.78$ psi/ft
Length of stand, $L_{std} = 93$ ft
Displacement of

Continued

Example 3.1—cont'd

$$4\frac{1}{2}\text{in. drillpipe,}\quad DSP_{4\frac{1}{2}} = 0.525\,\text{bbl/std}$$

$$2\frac{7}{8}\text{in. drillpipe,}\quad DSP_{2\frac{7}{8}} = 0.337\,\text{bbl/std}$$

Capacity of

$$12\frac{1}{4}\text{in. hole less pipe displacement,}\quad C_1 = 0.14012\,\text{bbl/ft}$$

$$4\frac{3}{4}\text{in. hole less pipe displacement,}\quad C_2 = 0.01829\,\text{bbl/ft}$$

Stands of pipe to be pulled = 10 stands
Wellbore configuration 1:

$$4\frac{1}{2}\text{ in. drillpipe in }12\frac{1}{4}\text{in. hole}$$

Wellbore configuration 2:

$$2\frac{7}{8}\text{ in. drillpipe in }4\frac{3}{4}\text{ in. hole}$$

Required:
Compare the loss in hydrostatic resulting from pulling 10 stands without filling from wellbore configuration 1 and wellbore configuration 2.

Solution:
Determine the displacement for 10 stands for wellbore configuration 1:

$$Displacement = (DSP_{ds})(\text{number of stands}) \tag{3.1}$$

where
DSP_{ds} = displacement of the drill string, bbls/std
$Displacement = (0.525)(10)$
$Displacement = \mathbf{5.25\ bbls}$
Determine hydrostatic loss for wellbore configuration 1:

$$Loss = \frac{\rho_m(Displacement)}{C_1} \tag{3.2}$$

where
ρ_m = Mud gradient, psi/ft
C_1 = Hole capacity less pipe displacement, bbl/ft

Example 3.1—cont'd

$$Loss = \frac{(0.78)(5.25)}{0.14012}$$

$$Loss = \mathbf{29\ psi}$$

Determine the displacement for 10 stands for wellbore configuration 2.

$Displacement = (DSP_{ds})(\text{number of stands})$

$Displacement = (0.337)(10)$

$Displacement = \mathbf{3.37\ bbls}$

Determine hydrostatic loss for wellbore configuration 2:

$$Loss = \frac{\rho_m(Displacement)}{C_2}$$

$$Loss = \frac{(0.78)(3.37)}{0.01829}$$

$$Loss = \mathbf{144\ psi}$$

The loss in hydrostatic for the first wellbore configuration is obviously insignificant for most drilling operations. The loss of almost 150 psi in hydrostatic for the second case is much more significant. The trip margin, which is the difference between the mud hydrostatic and the formation pore pressure, is often no more than 150 psi. Therefore, all things being equal, filling after 10 stands would be acceptable in the first instance, while continuous filling would be in order in the second case.

Periodic Filling Procedure

Periodic filling, which is filling the hole after pulling a specified number of stands, is the minimum requirement and is usually accomplished utilizing a pump stroke counter according to a schedule. The periodic filling procedure is as follows:

Periodic Filling Procedure

Step 1

Determine the pump capacity (C_p), bbls/stk.

Step 2

Determine the drill string displacement (DSP_{ds}), bbls/std, for each section of drill string.

Step 3

Determine the number of stands of each section of drill string to be pulled prior to filling the hole. (Usually every 5 stands of drill pipe, 3 stands of HWDP, and 1 stand of drill collars.)

Step 4

Determine the theoretical number of pump strokes required to fill the hole after pulling the number of stands determined in Step 3.

Step 5

Prior to reaching the critical interval, begin maintaining a record of the number of pump strokes required to fill the hole after pulling the number of stands determined in Step 3.

Maintain the data in tabular form, comparing the number of stands pulled with the actual strokes required to fill the hole, the number of strokes theoretically required, and the number of strokes required on the previous trip. These data, in tabular form, are the trip sheets. The trip sheet should be posted and maintained on the rig floor.

Step 6

Mix and pump a barite slug in order to pull the drill string dry. Wait for the hydrostatic inside the drill string to equalize.

Step 7

Pull the specified number of stands.

Step 8

Zero the stroke counter. Start the pump. Observe the return of mud to the surface and record in the appropriate column the actual number of strokes required to bring mud to the surface.

Step 9

Compare the actual number of strokes required to bring mud to the surface to the number of strokes required on the previous trip and the number of strokes theoretically determined.

The trip sheet generated by the periodic filling procedure is illustrated in Example 3.2:

Example 3.2

Given:

Pump capacity, $C_p = 0.1$ bbl/stk

Drill pipe displacement, $DSP_{ds} = 0.525$ bbl/std

Drill pipe $= 4\frac{1}{2}$in. 16.60 /ft

Drill pipe pulled between filling = 10 stands

Actual strokes required as illustrated in Table 3.1

Strokes required on previous trip as illustrated in Table 3.1

Required:

Illustrate the proper trip sheet for a periodic filling procedure.

Example 3.2—cont'd

Solution:

Theoretical strokes per 10 stands:

$$Strokes = \frac{DSP_{ds}(\text{number of stands})}{C_p} \tag{3.3}$$

where

DSP_{ds} = displacement of the drill string, bbl/std

C_p = pump capacity, bbl/stk

$$Strokes = \frac{(0.525)(10)}{0.1}$$

$$Strokes = \mathbf{52.5\ per\ 10\ stants}$$

The proper trip sheet for periodic filling is illustrated as Table 3.1.

Table 3.1 Trip sheet periodic filling procedure

Cumulative stands pulled	Actual strokes required	Theoretical strokes	Strokes required on previous trip
10	55	52.5	56
20	58	52.5	57
30	56	52.5	56
…	…	…	…

The periodic filling procedure represents the minimum acceptable filling procedure. The "flo-sho" or drilling fluid return indicator should not be used to indicate when circulation is established. It is preferable to zero the stroke counter, start the pump, and observe the flow line returns. As a matter of practice, the displacement should be determined for each different section of the drill string. The number of stands of each section to be pulled between fillings may vary. For example, the hole should be filled after each stand of drill collars since the drill collar displacement is usually approximately five times drill pipe displacement.

Continuous Filling Procedure

In critical well situations, continuous filling is recommended using a trip tank. A trip tank is a small-volume tank (usually less than 60 bbl) that permits the discerning of fractions of a barrel. The better arrangement is with the trip tank in full view of the driller or floor crew and rigged with a small centrifugal pump for filling the tank and continuously circulating the mud inside the tank through the bell nipple or drill pipe annulus and back into the trip tank. When that mechanical arrangement is used, the hydrostatic will never drop.

The procedure would be for the hole to be filled continuously. After each 10 (or some specified number of) stands, the driller would observe, record, and compare the volume pumped from the trip tank into the hole with the theoretical volume required. The procedure for continuously filling the hole using the trip tank would be as follows:

Step 1

Determine the drill string displacement (DSP_{ds}), bbl/std, for each section of drill string.

Step 2

Determine the number of stands of each section of drill string to be pulled prior to checking the trip tank. (Usually every 5 stands of drill pipe, 3 stands of HWDP, and 1 stand of drill collars.)

Step 3

Determine the theoretical number of barrels required to replace the drill string pulled from the hole. Observe the fill volume determined in Step 2 after reaching the number of stands determined in Step 1.

Step 4

Prior to reaching the critical interval, begin maintaining a record of the number of barrels required to maintain the hydrostatic during the pulling of the number of stands determined in Step 2.

Maintain the data in tabular form, comparing the number of stands pulled with the cumulative volume required to maintain the hydrostatic, the volume required as theoretically determined, and the volume required on the previous trip. These data, in tabular form, are the trip sheets. It should be posted and maintained on the rig floor.

Step 5

Mix and pump a barite slug in order to pull the drill string dry. Wait for the hydrostatic inside the drill string to equalize.

Step 6

Fill the trip tank and isolate the hole from the mud pits.

Step 7

Start the centrifugal pump and observe the return of mud to the trip tank.

Step 8

With the centrifugal pump circulating the hole, pull the number of stands specified in Step 2.

Step 9

After pulling the number of stands specified in Step 2, observe and record the number of barrels of mud transferred from the trip tank to the hole.

Step 10

Compare the number of barrels of mud transferred from the trip tank to the hole during this trip with the same volume transferred during the previous trip and the volume theoretically determined

The trip sheet generated by the continuous filling procedure is illustrated in Example 3.3:

Example 3.3

Given:

Drill pipe $= 4\frac{1}{2}$in. 16.60 /ft

Drill pipe displacement, $DSP_{ds} = 0.525$ bbl/std
Stands pulled between observations = 10 stands
Trip tank capacity is 60 bbls in $\frac{1}{4}$ barrel increments
Actual volume required as illustrated in Table 3.2
Volume required on previous trip as illustrated in Table 3.2

Required:

Illustrate the proper trip sheet for a continuous filling procedure.

Solution:

Determine theoretical volume per 10 stands.

$$Displacement = (DSP_{ds})\ (\text{number of stands})$$
$$Displacement = (0.525)\ (10)$$
$$Displacement = \mathbf{5.25\ bbls\ per\ 10\ stands}$$

The proper trip sheet for periodic filling is illustrated in Table 3.2.

Table 3.2 Trip sheet continuous filling procedure

Cumulative number of stands	Cumulative volume required	Cumulative theoretical volume	Previous trip
10	5.50	5.25	5.40
20	11.50	10.05	11.00
30	17.00	15.75	16.50
40	23.25	21.00	22.75
–	–	–	–

Generally, the actual volume of mud required to keep the hole full exceeds the theoretical calculations. The excess can be as much as 50%. On rare occasions, however, the actual volume requirements to keep the hole full are consistently less than those theoretically determined. Therefore, it is vitally important that the trip sheets from previous trips be kept for future reference. Whatever the fill pattern, it must be recorded faithfully for future comparison.

Tripping into the Hole

In specific instances, though not always, it is prudent to monitor displacement while tripping in the hole to insure that fluid displacement is not excessive. The best means of measuring the displacement going in the hole is to displace directly into the isolated trip tank. A trip sheet exactly like Table 3.2 should be maintained. All too often crews are relaxed and not as diligent as necessary on the trip in the hole. As a result, industry history has recorded several instances where excessive displacement went unnoticed and severe pressure control problems resulted.

Calculations and experience prove that swabbing can occur while tripping out or in. Swab pressures should be calculated, as additional trip time can be more costly and hazardous than insignificant swab pressures. Swab pressures are real and should be considered. If a well is swabbed in on a trip in the hole, the influx will most probably be inside the drill pipe rather than the annulus because the frictional pressure is greater inside the drill string.

Further, the potential for problems does not disappear once the bit is on the bottom. The pit level should be monitored carefully during the first circulation after reaching the bottom. The evolution of the trip gas from the mud as it is circulated to the surface may reduce the total hydrostatic sufficiently to permit a kick.

Special attention is due when using inverted oil-emulsion systems. Historically, influxes into oil muds are difficult to detect. Because gas is infinitely soluble in oil, significant quantities of gas may pass undetected by the usual means until the pressure is reduced to the bubble point for that particular hydrocarbon mixture. At that point, the gas can flash out of solution, unload the annulus, and result in a kick.

SHUT-IN PROCEDURE

Well Kicks While Tripping

When a trip sheet is maintained and the well fails to fill properly, the correct procedure is as follows:

Step 1

The hole is observed not to be filling properly. Discontinue the trip and check for flow.

Step 2

If the well is observed to be flowing, space out as necessary.

Step 3

Stab a full opening valve in the drill pipe and shut in the drill pipe.

Step 4

Open the choke line, close the blowout preventers, and close the choke, pressure permitting.

Step 5

Observe and record the shut-in drill pipe pressure, the shut-in annulus pressure, and the volume of formation fluid that has invaded the wellbore.

Step 6

Repeat Step 5 at 15 min intervals.

Step 7

Prepare to strip or snub back to the bottom.

The following is a discussion of each step:

Step 1

The hole is observed not to be filling properly. Discontinue the trip and check for flow.

If the hole is not filling properly, it should be checked for flow. The observation period is a function of experience in the area, the productivity of the productive formation, the depth of the well, and the mud type. Under most conditions, 15 min is sufficient. In a deep well below 15,000 ft or if oil-based mud is being used, the observation period should be extended to a minimum of 30 min.

If the well is not observed to be flowing, the trip can be continued with the greatest caution. If a periodic filling procedure is being used, the hole should be filled after each stand and checked for flow until the operation returns to normal. If, after pulling another designated number of stands, the well continues to fill improperly, the trip should be discontinued.

If the well is not flowing when the trip is discontinued, the bit may be returned cautiously to bottom. In the event that the bit is returned to bottom, the displacement of each stand should be monitored closely, and the well should be checked for flow after each stand.

If at any time the well is observed to be flowing, the trip should be discontinued. It is well-known that in many areas of the world, trips are made with the well flowing; however, these should be considered isolated instances and special cases.

Step 2

If the well is observed to be flowing, space out as necessary.

The drill string should be spaced out to insure that there is not a tool joint in the rams. If that is not a consideration, a tool joint is normally spotted at the connection position.

Step 3

Stab a full opening valve in the drill pipe and shut in the drill pipe.

The drill pipe should be shut in first. It is well-known that the ball valves normally used to shut in the drill pipe are difficult to close under flow or pressure.

Step 4

Open the choke line, close the blowout preventers, and close the choke, pressure permitting.

This step represents a soft shut-in. For a discussion of the soft shut-in as opposed to the hard shut-in, refer to the shut-in procedure for the driller's method in Chapter Two.

Step 5

Observe and record the shut-in drill pipe pressure, the shut-in annulus pressure, and the volume of formation fluid that has invaded the wellbore.

Step 6

Repeat Step 5 at 15 min intervals.

If the well has been swabbed in, the bubble should be below the bit, as illustrated in Fig. 3.1. In that event, the shut-in drill pipe pressure will be equal to the shut-in casing pressure. The pressures and influx must be monitored at 15 min intervals in order to insure that the well is effectively shut in, to establish the true reservoir pressure, and to monitor bubble rise. Bubble rise is discussed in Chapter Four.

Step 7

Prepare to strip or snub back to bottom.

Stripping is a simple operation. However, stripping does require a means of bleeding and accurately measuring small volumes of mud as the drill string is stripped in the hole. A trip tank is adequate for measuring the mud volumes bled. Alternatively, a service company pump truck can be rigged up to the annulus, and the displacement can be measured into its displacement tanks. If the gain is large and the pressures are high, stripping through the rig equipment may not be desirable. This point is more thoroughly discussed in snubbing operations in Chapter Six.

Once shut in, the well is under control. Properly done, the surface pressure on the well should be less than 500 psi, which is almost insignificant.

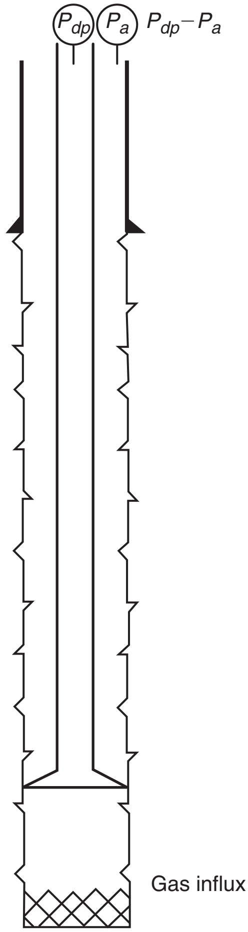

Fig. 3.1 Influx swabbed in.

With the well shut in, there is adequate time to consider alternatives without danger of disaster. The well that has been swabbed in is a well that was under control when the bit started off the bottom. Properly done, it should be a simple procedure to return the well to full control.

Once the well is shut in and under control, the options are as follows:

STRIPPING IN THE HOLE

Stripping in is not complicated if a few simple rules and concepts are observed. The procedure is as follows:

Step 1

Install a back-pressure valve on top of the safety valve in the drill string. Equalize the pressure and open the safety valve.

Step 2

Determine the displacement in barrels per stand of the drill string to be stripped into the hole. Consider that the inside of the drill string will be void.

Step 3

Determine the anticipated increase in surface pressure when the bit enters the influx according to Eq. (3.4):

$$\Delta P_{incap} = \frac{DSP_{ds}}{C_{dsa}}\left(\rho_m - \rho_f\right) \quad (3.4)$$

where

DSP_{ds} = displacement of drill string, bbl/std

C_{dsa} = capacity of drill string annulus, bbl/ft

ρ_m = mud gradient, psi/ft

ρ_f = influx gradient, psi/ft

$$\rho_f = \frac{S_g P_b}{53.3 z_b T_b} \quad (3.5)$$

where

S_g = specific gravity of gas

P_b = bottom-hole pressure, psi

T_b = bottom-hole temperature, °Rankine

z_b = compressibility factor at bottom-hole conditions

Step 4

Determine the anticipated top of the influx, TOI, pursuant to Eq. (3.6):

$$TOI = D - \frac{\mathit{Influx\ volume}}{C_h} \quad (3.6)$$

where

D = well depth, feet

C_h = hole capacity, bbl/ft

Step 5

Prepare to lubricate the drill string with water as it passes through the surface equipment.

Step 6

Lower one stand into the hole.

Step 7

At the same time, bleed and precisely measure the displacement determined in Step 2.

Step 8

Shut in the well.

Step 9

Read and record in tabular form the shut-in casing pressure. Compare the shut-in casing pressures before and after the stand was lowered into the hole.

Note, the shut-in casing pressure should remain constant until the bit reaches the influx.

Step 10

Repeat Step 9 until the bit reaches the top of the influx as determined in Step 4.

Step 11

When the bit reaches the top of the influx as determined in Step 4, the shut-in surface pressure will increase even after the proper volume of mud is released.

Read and record the new shut-in casing pressure and compare with the original shut-in casing pressure and the anticipated increase in shut-in casing pressure as determined in Step 2.

The new shut-in casing pressure should not be greater than the original shut-in casing pressure plus the anticipated increase.

Step 12

Repeat Step 11 until the bit is on the bottom.

Step 13

Once the bit is on the bottom, circulate out the influx using the driller's method as outlined in Chapter Two.

Step 14

If necessary, circulate and raise the mud weight and trip out of the hole.

Each step will be discussed as appropriate:

Step 1

Install a back-pressure valve on top of the safety valve in the drill string. Equalize the pressure and open the safety valve.

Step 2

Determine the displacement in barrels per stand of the drill string to be stripped into the hole. Consider that the inside of the drill string will be void.

Step 3

Determine the anticipated increase in surface pressure when the bit enters the influx according to Eq. (3.4):

$$\Delta P_{incap} = \frac{DSP_{ds}}{C_{dsa}} \left(\rho_m - \rho_f \right)$$

When the bit enters the influx, the influx will become longer because it will then occupy the annular area between the drill string and the hole as opposed to the open hole. Therefore, the volume of mud that is bled from the well will be replaced by the increased length of the influx. Provided that the volume of mud bled from the well is exactly as determined, the result is that the surface pressure will increase automatically by the difference between the hydrostatic of the mud and the hydrostatic of the influx, and the bottom-hole pressure will remain constant. No additional influx will be permitted.

Step 4

Determine the anticipated top of the influx, TOI, pursuant to Eq. (3.6):

$$TOI = D - \frac{Influx\ volume}{C_h}$$

It is necessary to anticipate the depth at which the bit will enter the influx. As discussed, the annular pressure will suddenly increase when the bit enters the influx.

Step 5

Prepare to lubricate the drill string with water as it passes through the surface equipment.

Lubricating the string as it is lowered into the hole will reduce the weight required to cause the drill string to move. In addition, the lubricant will reduce the wear on the equipment used for stripping.

Step 6

Lower one stand into the hole.

It is important that the drill string be stripped into the hole, stand by stand.

Step 7

At the same time, bleed and precisely measure the displacement determined in Step 2.

It is vital that the volume of mud removed is exactly replaced by the drill string that is stripped into the well.

Step 8

Shut in the well.

Step 9

Read and record in tabular form the shut-in casing pressure. Compare the shut-in casing pressures before and after the stand was lowered into the hole.

Note, the shut-in casing pressure should remain constant until the bit reaches the influx.

It is important to monitor the surface pressure after each stand. Prior to the bit entering the influx, the surface pressure should remain constant. However, if the influx is gas and begins to migrate to the surface, the surface pressure will slowly begin to increase. The rate of increase in surface pressure indicates whether the increase is caused by influx migration or penetration of the influx.

If the increase is due to influx penetration, the pressure will increase rapidly during the stripping of one stand. If the increase is due to influx migration, the increase is almost imperceptible for a single stand. Bubble migration and the procedure for stripping in the hole with influx migration are discussed in Chapter Four.

Step 10

Repeat Step 9 until the bit reaches the top of the influx as determined in Step 4.

Step 11

When the bit reaches the top of the influx as determined in Step 4, the shut-in surface pressure will increase even after the proper volume of mud is released.

Read and record the new shut-in casing pressure and compare with the original shut-in casing pressure and the anticipated increase in shut-in casing pressure as determined in Step 2.

The new shut-in casing pressure should not be greater than the original shut-in casing pressure plus the anticipated increase.

Step 12

Repeat Step 11 until the bit is on the bottom.

Step 13

Once the bit is on the bottom, circulate out the influx using the driller's method as outlined in Chapter Two.

Step 14

If necessary, circulate and raise the mud weight and trip out of the hole.

The procedure for stripping is illustrated in Example 3.4:

Example 3.4

Given:

Wellbore = Fig. 3.2

Number of stands pulled = 10 stands

Continued

Example 3.4—cont'd

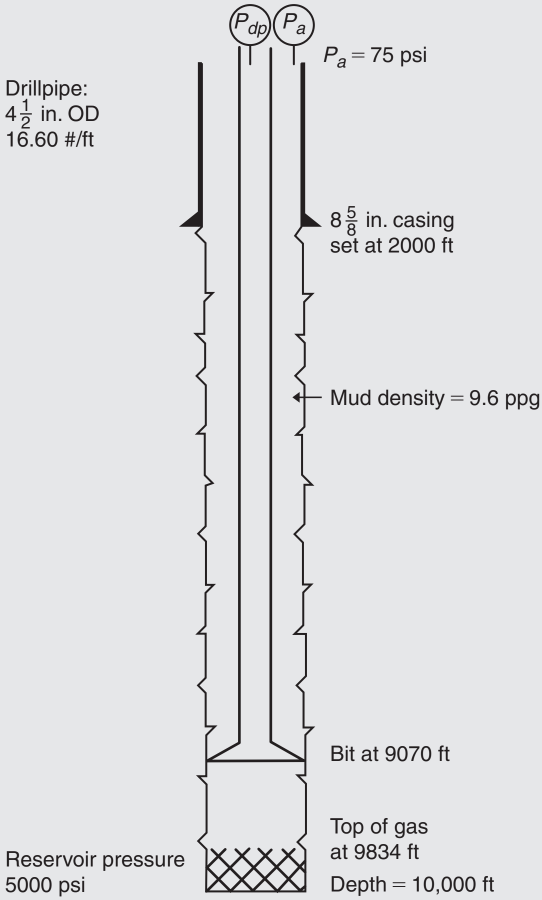

Fig. 3.2 Wellbore schematic while tripping with a kick on bottom.

Length per stand, $L_{std} = 93$ ft/std
Stands stripped into the hole = 10 stands
Drill string to be stripped = $4\frac{1}{2}$in. 16.60#/ft
Drill string displacement, $DSP_{ds} = 2$ bbl/std
Mud density, $\rho = 9.6$ ppg
Influx = 10 bbls of gas
Annular capacity, $C_{dsa} = 0.0406$ bbl/ft
Depth, $D = 10{,}000$ ft
Hole diameter, $D_h = 7\frac{7}{8}$in.
Hole capacity, $C_h = 0.0603$ bbl/ft
Bottom-hole pressure, $P_b = 5000$ psi

Example 3.4—cont'd

Bottom-hole temperature, $T_b = 620°R$
Gas specific gravity, $S_g = 0.6$
Shut-in casing pressure, $P_a = 75$ psi
Compressibility factor, $z_b = 1.1$

Required:
Describe the procedure for stripping the 10 stands back to the bottom.

Solution:
Determine influx height, h_b:

$$h_b = \frac{Influx\ volume}{C_h} \tag{3.7}$$

where
C_h = capacity, bbl/ft:

$$h_b = \frac{10}{0.0603}$$
$$h_b = \mathbf{166\ feet}$$

Determine the top of the influx using Eq. (3.6):

$$TOI = D - \frac{Influx\ volume}{C_h}$$
$$TOI = 10,000 - \frac{10}{0.0603}$$
$$TOI = \mathbf{9834\ feet}$$

The bit will enter the influx on the ninth stand.
Determine the depth to the bit:

$$Depth\ to\ bit = D - (\text{number of stands})(L_{std}) \tag{3.8}$$

where
D = well depth, feet
L_{std} = length of a stand, feet
$Depth\ to\ bit = 10,000—(10)(93)$
$Depth\ to\ bit = \mathbf{9070\ ft}$

Determine ΔP_{incap} using Eq. (3.4):

$$\rho_f = \frac{S_g(P_b)}{53.3 z_b T_b}$$
$$\rho_f = \frac{0.6(5000)}{53.3(1.1)(620)}$$
$$\rho_f = \mathbf{0.0825\ psi/ft}$$

Continued

Example 3.4—cont'd

$$\Delta P_{incap} = \frac{DSP_{ds}}{C_{dsa}}\left(\rho_m - \rho_f\right)$$

$$\Delta P_{incap} = \frac{2}{0.0406}(0.4992 - 0.0825)$$

$$\Delta P_{incap} = \mathbf{20.53\ psi/std}$$

$$\Delta P_{incap} = \mathbf{0.22\ psi/ft}$$

Therefore, lower 8 stands, bleeding and measuring two barrels with each stand. The shut-in casing pressure will remain constant at 75 psi.

Lower the ninth stand, bleeding 2 bbls. Observe that the shut-in casing pressure increases to 91 psi:

$$P_{an} = P_a + \Delta P_{incap}(\mathit{feet\ of\ influx\ penetrated}) \qquad (3.9)$$

where

P_a = shut-in casing pressure, psi

ΔP_{incap} = increase in pressure with bit penetration

$P_{an} = 75 + 0.22(166 - 93)$

$P_{an} = \mathbf{91\ psi}$

Lower the 10th stand, bleeding 2 bbls. Observe that the shut-in casing pressure increases to 112 psi.

Maintain the results as in Table 3.3. Table 3.3 summarizes the stripping procedure. Note that if the procedure is properly done, the shut-in casing pressure remains constant until the bit penetrates the influx. This is true only if the influx is not migrating. The stripping procedure must be modified to

Table 3.3 Stripping procedure Example 3.4

Stand number	Beginning shut-in time	Initial annulus pressure	Barrel bled	Final shut-in annulus pressure
1	0800	75	2	75
2	0810	75	2	75
3	0820	75	2	75
4	0830	75	2	75
5	0840	75	2	75
6	0850	75	2	75
7	0860	75	2	75
8	0900	75	2	75
9	0910	75	2	91
10	0920	91	2	112

accommodate the case of migrating influx. The proper stripping procedure, including migrating influx, is presented in Chapter Four.

Example 3.4 is further summarized in Fig. 3.3. Fig. 3.3 illustrates the relative positions of the bit with respect to the influx during stages of the stripping operation. With 8 stands stripped into the hole, the bit is at 9820 ft, or 14 ft above the top of the influx. Until then, the shut-in surface pressure has remained constant at 75 psi. When the 9th stand is ran, the bit enters the influx and the shut-in surface pressure increases to 91 psi. On the

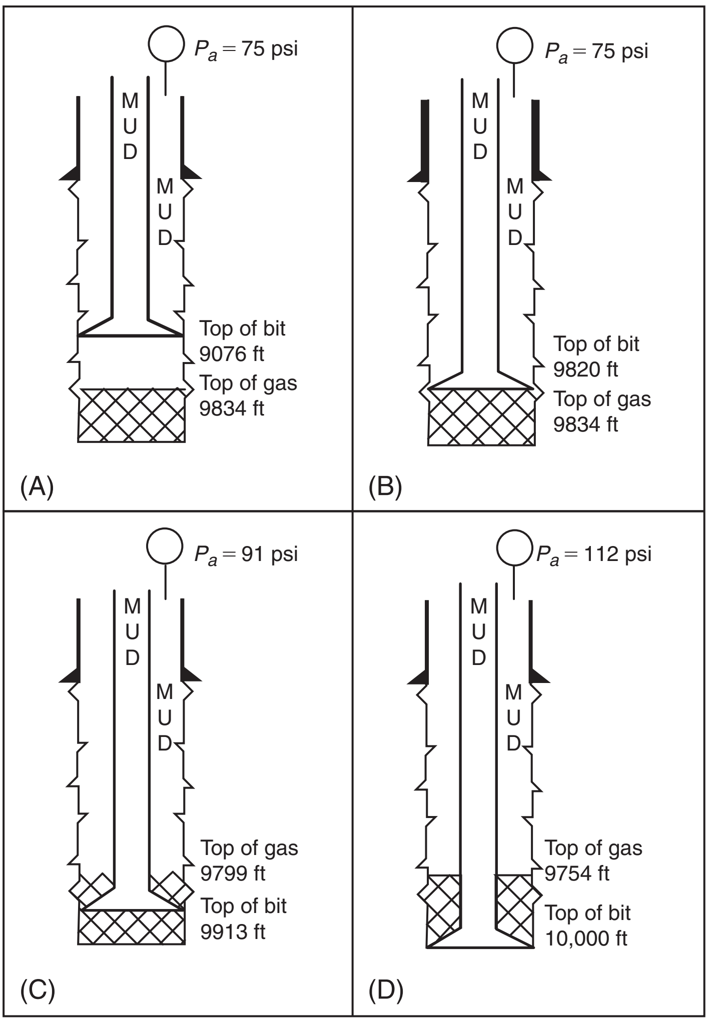

Fig. 3.3 (A) 0 stands in; (B) 8 stands in; (C) 9 stands in; and (D) 10 stands in.

last stand, the bit is in the influx and the shut-in surface pressure increases to 112 psi. Throughout the stripping procedure, the bottom-hole pressure has remained constant at 5000 psi.

One should not conclude that stripping is performed while keeping the shut-in surface pressure constant. As illustrated in Example 3.4, had keeping the shut-in surface pressure constant been the established procedure, the well would have been underbalanced during the time that the last two stands were ran, and additional influx would have resulted. Certainly, the shut-in surface pressure must be considered. However, it is only one of many important factors.

Once the bit is back on bottom, the influx can easily be circulated to the surface using the first circulation of the driller's method as outlined in Chapter Two. With the influx circulated out, the well is under control and in the same condition as before the trip began.

CHAPTER FOUR

Special Conditions Problems and Procedures in Well Control

9 November

Took kick of approximately 100 bbls at 1530 hours. Shut in well with 2400 psi on drill pipe and casing. At 1730 pressure increased to 2700 psi. At 1930 pressure increased to 3050 psi.

10 November

0200 pressure is 2800 psi. Determined total gain was 210 bbls. At 0330 pressure is 3800 psi. Bled 10 bbls of mud and pressure dropped to 3525 psi. At 0445 pressure is 3760 psi and building 60 psi every 15 min. At 0545 pressure is 3980 psi and building 40 psi every 15 min. Pressure stabilized at 4400 psi at 1000 hours.

As illustrated in this drilling report, the circumstances surrounding a kick do not always fit the classical models. In this drilling report from southeast New Mexico, the bit was at 1500 ft and total depth was below 14,000 ft. In addition, the surface pressures were changing rapidly. These conditions are not common to classical pressure control procedures and must be given special consideration.

This chapter is intended to discuss nonclassical situations. It is important to understand classical pressure control. However, for every well control situation that fits within the classical model, there is a well control situation that bears no resemblance to the classical. According to statistics reported by the industry to the UK Health and Safety Executive, classical kicks are uncommon. For the three-year period from 1990 to 1992, of the 179 kicks reported, only 39 (22%) were classic.

The student of well control must be aware of the situations in which classical procedures are appropriate and be capable of distinguishing those nonclassical situations where classical procedures have no application. In addition, when the nonclassical situation occurs, it is necessary to know

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and understand the alternatives and which one has the greatest potential for success. In the nonclassical situation, the use of classical procedures may result in the deterioration of the well condition to the point that the well is lost or the rig is burned.

SIGNIFICANCE OF SURFACE PRESSURES

In any well control situation, the pressures at the surface reflect the heart of the problem. A well out of control must obey the laws of physics and chemistry. Therefore, it is for the well control specialists to analyze and understand the problem. The well will always accurately communicate its condition. It is for us to interpret the communication properly.

A Kick Is Taken While Drilling

As discussed in Chapter two on classical pressure control, when a kick is taken while drilling and the well is shut in, the shut-in drill pipe pressure and the shut-in casing pressure are routinely recorded. The relationship between these two pressures is very important. The applicability of the classical Driller's or wait-and-weight method must be considered in light of the relationship between the shut-in drill pipe pressure and the shut-in casing pressure.

Consider the classical U-tube model presented as Fig. 4.1. In this figure, the left side of the U-tube represents the drill pipe, while the right side represents the annulus. When the well is first shut in, the possible relationships between the shut-in drill pipe pressure, P_{dp}, and the shut-in annulus pressure, P_a, are described in inequalities (4.1), (4.2) and Eq. (4.3) as follows:

$$P_a > P_{dp} \tag{4.1}$$

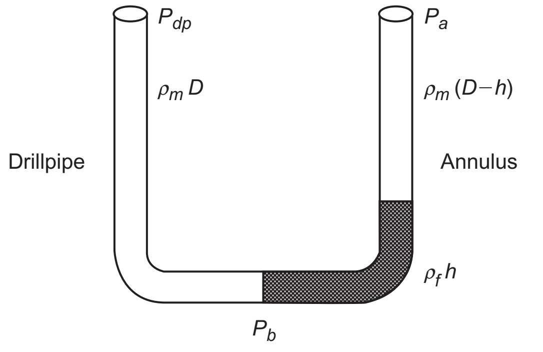
$$P_a < P_{dp} \tag{4.2}$$

$$P_a \cong P_{dp} \tag{4.3}$$

With respect to the U-tube model in Fig. 4.1, the bottom-hole pressure, P_b, may be defined by the conditions on the drill pipe side and the conditions on the annulus side pursuant to Eqs. (2.6) and (2.7).

On the drill pipe side, P_b is given by Eq. (2.6) as follows:

$$P_b = \rho_m D + P_{dp}$$



Where:
P_{dp} = Shut-in drillpipe pressure, psi
P_a = Shut-in annulus pressure, psi
D = Depth of well, feet
ρ_m = Mud density, psi/ft
ρ_f = Influx density, psi/ft
h = Height of influx, psi/ft
P_b = Bottomhole pressure, psi

Fig. 4.1 Classical U-tube model.

On the annulus side, P_b is given by Eq. (2.7) as follows:

$$P_b = \rho_f h + \rho_m (D - h) + P_a$$

Eqs. (2.6) and (2.7) may be rearranged to give the following expressions for P_{dp} and P_a, respectively:

$$P_{dp} = P_b - \rho_m D$$

and

$$P_a = P_b - \rho_m (D - h) - \rho_f h$$

To illustrate the significance of the relationship between the shut-in drill pipe pressure and the shut-in annulus pressure, it is first assumed that a kick is taken, the well is shut in, and the shut-in annulus pressure is greater than the shut-in drill pipe pressure as expressed in inequality (4.1):

$$P_a > P_{dp}$$

Substituting Eq. (2.6) for the right side of the inequality and Eq. (2.7) for the left side of the inequality results in the following expression:

$$P_b - \rho_m (D - h) - \rho_f h > P_b - \rho_m D$$

Expanding the terms gives

$$P_b - \rho_m D + \rho_m h - \rho_f h > P_b - \rho_m D$$

Adding $\rho_f h$ and $\rho_m D$ to both sides and subtracting P_b from both sides gives

$$P_b - P_b + \rho_m D - \rho_m D + \rho_m h + \rho_f h - \rho_f h > P_b - P_b + \rho_m D - \rho_m D + \rho_f h$$

Simplifying the above equation results in the following:

$$\rho_m h > \rho_f h$$

Finally, dividing both sides of the inequality by h gives the consideration that

$$\rho_m > \rho_f \tag{4.4}$$

The significance of the analysis is this: When a well is on bottom drilling, a kick is taken, and the well is shut in pursuant to the condition illustrated by the U-tube model in Fig. 4.1. One of the conditions presented as expressions (4.1–4.3) must describe the relationship between the shut-in drill pipe pressure and the shut-in casing pressure.

For the purpose of illustration in this analysis, it was assumed that the shut-in casing pressure was greater than the shut-in drill pipe pressure as described in inequality (4.1), which results in inequality (4.4). Therefore, it is a certainty that when a well kicks and is shut in, if the shut-in annulus pressure is greater than the shut-in drill pipe pressure, the density of the fluid that has entered the wellbore must be less than the density of the mud that is in the wellbore.

If the mud density is 15 ppg, the pressure on the annulus, P_a, must be greater than the pressure on the drill pipe, P_{dp}, since the heaviest naturally occurring salt water is about 9–10 ppg. If the mud density is 9 ppg and P_a is greater than P_{dp}, the fluid entering the wellbore is gas or some combination of gas and oil or water. (Determining the density of the fluid that entered the wellbore is illustrated later in this chapter.)

Consider that by similar analysis it can be shown that if the inequality (4.2) or Eq. (4.3) describes the relationship between the shut-in drill pipe pressure and the shut-in annulus pressure, the following must be true:

If

$$P_a < P_{dp}$$

it must follow that

$$\rho_m < \rho_f \tag{4.5}$$

or if

$$P_a \cong P_{dp}$$

it must follow that

$$\rho_m \cong \rho_f \tag{4.6}$$

That is, if the shut-in annulus pressure is less than or equal to the shut-in drill pipe pressure, the density of the fluid that has entered the wellbore must be greater than or equal to the density of the mud in the wellbore!

Further, when the density of the drilling mud in the wellbore is greater than 10 ppg or when the influx is known to be significantly hydrocarbon, it is theoretically not possible for the shut-in casing pressure to be equal to or less than the shut-in drill pipe pressure.

Now, here is the point, and it is vitally important that it be understood. If the reality is that the well is shut in, the density of the mud exceeds 10 ppg, or the fluid that has entered the wellbore is known to be significantly hydrocarbon, and the shut-in annulus pressure is equal to or less than the shut-in drill pipe pressure, the mathematics and reality are incompatible.

When the mathematics and reality are incompatible, the mathematics has failed to describe reality, or the gauges are not reading correctly. In other words, something is wrong downhole or with the surface equipment. Something is different downhole than assumed in the mathematical U-tube model, and that something is usually that lost circulation has occurred and the well is blowing out underground. The shut-in annulus pressure is influenced by factors other than the shut-in drill pipe pressure.

As a test, pump a small volume of mud down the drill pipe with the annulus shut in and observe the shut-in annulus pressure. No response indicates lost circulation and an underground blowout.

Whatever the cause of the incompatibility between the shut-in casing pressure and the shut-in drill pipe pressure, the significance is that under these conditions, the U-tube model is not applicable and *CLASSICAL PRESSURE CONTROL PROCEDURES ARE NOT APPLICABLE.* The Driller's method will not control the well! The wait-and-weight method will not control the well! "Keep the drill pipe pressure constant" has no more meaning under these conditions than any other five words in any language. "Pump standing on left foot" has as much significance and as much chance of success as "keep the drill pipe pressure constant!"

Under these conditions, nonclassical pressure control procedures must be used. There are no established procedures for nonclassical pressure control operations. Each instance must be analyzed considering the unique and individual conditions, and the procedure must be detailed accordingly.

Influx Migration

To suggest that a fluid of lesser density will migrate through a fluid of greater density should be no revelation. However, in drilling operations, there are many factors that affect the rate of influx migration. In some instances, the influx has been known not to migrate.

In recent years, there has been considerable research related to influx migration. In the final analysis, the variables required to predict the rate of influx migration are simply not known in field operations. The old field rule of migration of approximately 1000 ft/h has proved to be as reliable as many much more theoretical calculations.

Some interesting and revealing observations and concepts have resulted from the research that has been conducted. Whether or not the influx will migrate depends upon the degree of mixing that occurs when the influx enters the wellbore. If the influx that enters over a relatively long period of time is significantly distributed as small bubbles in the mud and the mud is viscous, the influx may not migrate. If the influx enters the wellbore in a continuous bubble, as is the case when the influx is swabbed into the wellbore, it is more likely to migrate. As the viscosity approaches that of water, the probability of migration increases.

Researchers have observed many factors that will influence the rate of migration of an influx. For example, a migrating influx in a vertical annulus will travel up one side of the annulus with liquid backflow occupying an area opposite the influx. In addition, the migrating velocity of an influx is affected by annular clearances. The smaller the annular clearances, the slower the influx will migrate. The greater the density difference between the influx and the drilling mud, the faster the influx will migrate.

Therefore, the composition of the influx will affect the rate of migration, as will the composition of the drilling fluid. Further, the rate of migration of an influx is reduced as the viscosity of the drilling mud is increased. Finally, an increase in the velocity of the drilling fluid will increase the migration velocity of the influx since drilling fluids are shear thinning. Obviously, without specific laboratory tests on the drilling fluid, the influx fluid, and the resulting mixture of the fluids in question, predictions concerning the behavior of an influx would be virtually meaningless.

As previously stated, the surface pressures are a reflection of the conditions in the wellbore. Influx migration can be observed and analyzed from the changes in the shut-in surface pressures. Basically, as the influx migrates toward the surface, the shut-in surface pressure increases provided that the geometry of the wellbore does not change. An increase in the surface pressure is the result of the reduction in the drilling mud hydrostatic above the influx as it migrates through the drilling mud toward the surface.

As the influx migrates and the surface pressure increases, the pressure on the entire wellbore also increases. Thereby, the system is superpressured until the fracture gradient is exceeded or until mud is released at the surface, permitting the influx to expand properly. The procedures for controlling the pressures in the wellbore as the influx migrates are discussed later in this section.

At this point, it is important to understand that even under ideal conditions, the surface annular pressure will increase as the influx migrates, provided that the geometry of the wellbore does not change. If the casing is larger in the upper portion of the wellbore and the influx is permitted to expand properly, the surface pressure will decrease as the length of the influx shortens in the larger diameter casing. After decreasing as the influx enters the larger casing, the surface pressure will increase as the influx continues to migrate toward the surface.

A few field examples illustrate the points discussed. At the well in southeastern New Mexico from which the drilling report at the beginning of this chapter was excerpted, a 210 bbl influx was taken while on a trip at 14,000 ft. The top of the influx in the $6\frac{1}{2}$in. hole was calculated to be at 8326 ft. The kick was taken at 1530 hours and migrated to the surface through the 11.7 ppg water-based mud at 1000 hours the following morning. The average rate of migration was 450 ft/h.

At the Pioneer Corporation Burton #1 in Wheeler County, Texas, all gas was circulated out of the wellbore at the end of each day for more than 1 month. In this case, the gas migrated from 13,000 ft to the surface in the 7 in. casing by $2\frac{7}{8}$in. tubing annulus in approximately 8 h. The average rate of migration under those conditions was calculated to be 1600 ft/h. However, the pressure was recorded and the rate of rise was exponential.

It is generally considered that an influx will migrate faster in a directional well (not horizontal) with all other factors being equal (Fig. 4.2). At a directional well in New Zealand, 7 in. casing had been set to 2610 m, and a 6 in.

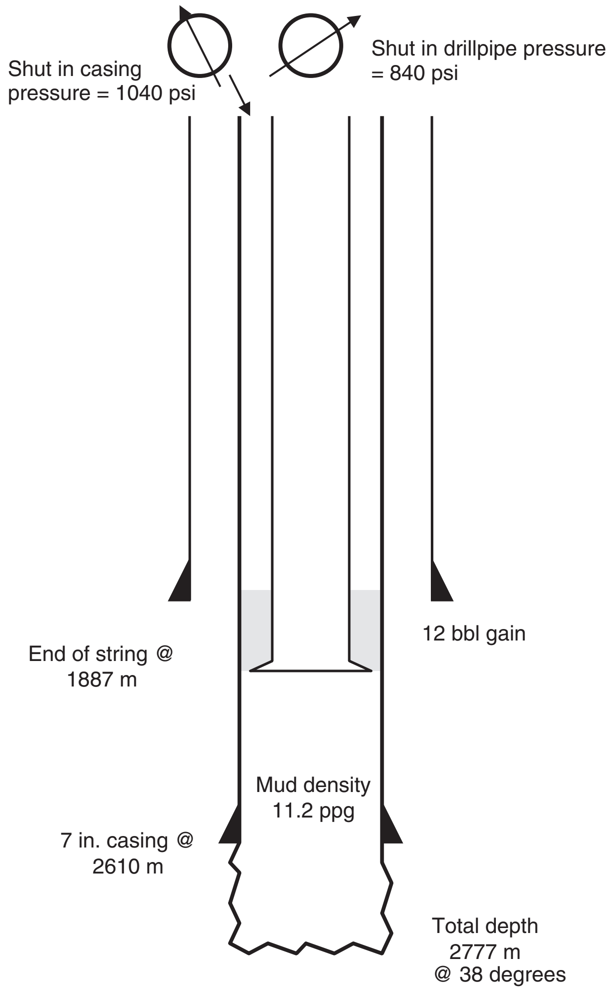


Fig. 4.2 Directional well in New Zealand.

core was being recovered from 2777 m measured depth, 2564 m true vertical depth. The wellbore was deviated 38 degrees from vertical at an azimuth of 91 degrees. The gel polymer mud density was 11.2 ppg, the plastic viscosity was 29 cp, and the yield point was 29 lbf/100 ft^2.

At 0700 hours with the core bit at 1884 m on the trip out of the hole to recover the core, an influx was taken, and the well was shut in. A 12 bbl influx was recorded. The shut-in drill pipe and casing pressures were 830 and 1040 psi, respectively.

Analysis of the pressure data indicated that the top of the influx was at 1428 m or 4685 ft. Preparations were being made to strip the core bit back to bottom. During the preparations, the influx migrated, reaching the surface before stripping operations could be commenced. Gas was detected at the surface at 1030 hours for a migration rate of 1330 ft/h.

More often than one would think, the influx will not migrate. Consider another well in New Zealand where 7 in. casing had been set at 2266 m (Fig. 4.3). After coring to a total depth of 2337 m, a trip was commenced

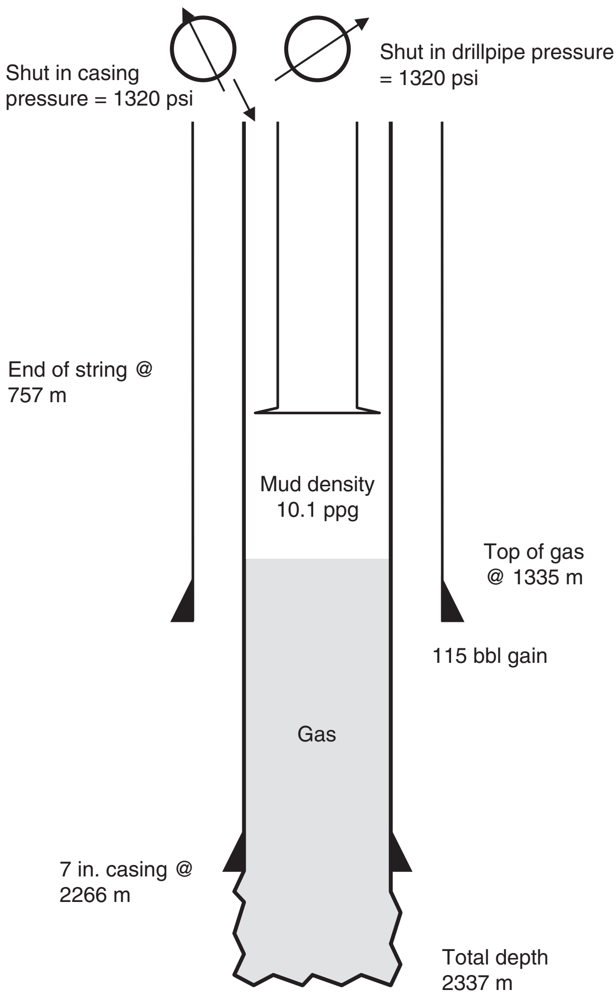


Fig. 4.3 Well with no gas migration.

to retrieve the core. The gel polymer mud had a density of 10.1 ppg, a plastic viscosity of 14 cp, a yield point of 16 lbf/100 ft^2, and a funnel viscosity of 40 s/L.

With the core bit at 757 m on the trip out, a gain of 3 bbls was observed. The well was shut in with a total gain of 6 bbls. The shut-in drill pipe and annulus pressures were equal at 350 psi. The kelly was picked up. The choke was opened, and the well was circulated. When the well was shut in the second time, the total gain was 115 bbls, and the shut-in surface pressures were equal at 1350 psi.

Calculations indicated that the top of the influx was only 1335 m from the surface. With these conditions, intuition and experience would strongly suggest that the influx would rise rapidly to the surface. The operator decided to permit the influx to migrate to the surface. Accordingly, the well was observed for 3 days. Ironically, the surface pressures remained constant at 1320 psi, indicating no influx movement.

During the next 24 h, the drill string was stripped back to the bottom of the hole. As the drill string was being stripped, 7 bbls of gas was randomly bled from the annulus along with the appropriate quantity of mud, which was replaced by the drill string. The remainder of the original 115 bbls of gas was in a bubble on the bottom of the hole and had to be circulated to the surface.

At the E. N. Ross No. 2 near Jackson, Mississippi, a 260 bbl kick was taken inside a $7\frac{5}{8}$in. liner while out of the hole on a 19,419 ft sour gas well. The top of the influx was calculated to be at 13,274 ft. A 17.4 ppg oil-based mud was being used. The initial shut-in surface pressure was 3700 psi. The pressure remained constant for the next 17 days, while snubbing equipment was being rigged up, indicating that the influx did not move during that 17 days. After 17 days, the influx began to migrate into the $9\frac{5}{8}$in. intermediate casing, and the surface pressure declined accordingly. Six days later, the influx was encountered during snubbing operations at 10,000 ft. The influx had migrated only 3274 ft in 6 days. Consider Example 4.1:

Example 4.1

Given:

Wellbore schematic = Figs. 4.4 and 4.5

Top of $7\frac{5}{8}$in. liner, $D_t = 13{,}928$ ft

Well depth, $D = 19{,}419$ ft

Example 4.1—cont'd

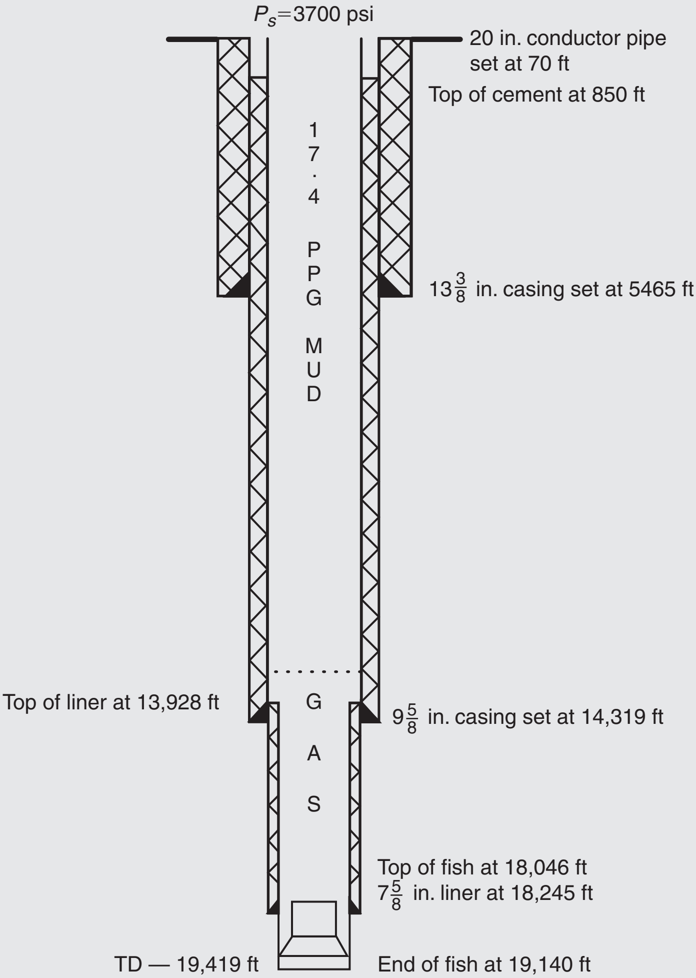


Fig. 4.4 E. N. Ross No. 2 conditions after initial kick.

Influx volume = 260 bbl
Capacity of casing, $C_c = 0.0707$ bbl/ft
Mud weight, $\rho = 17.4$ ppg OBM
Mud gradient, $\rho_m = 0.9048$ psi/ft
Bottom-hole pressure, $P_b = 16{,}712$ psi
Bottom-hole temperature, $T_b = 772°R$
Temperature at 10,200 ft, $T_x = 650°R$
Influx gradient, $\rho_f = 0.163$ psi/ft on bottom

Continued

Example 4.1—cont'd

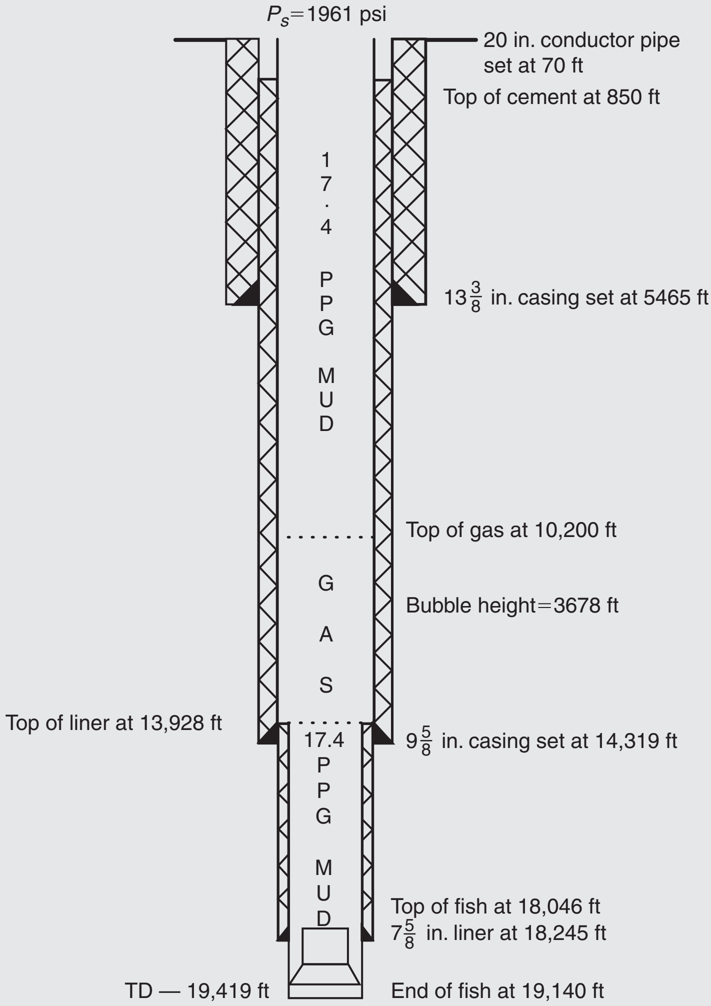


Fig. 4.5 E. N. Ross No. 2 after bubble migration.

$$\rho_f = 0.158 \text{ psi/ft inside } 9\frac{5}{8}$$

Compressibility factor at

10,200 ft, $z_x = 1.581$

19,419 ft, $z_b = 1.988$

Required:

Determine the surface pressure when the influx has migrated to 10,200 ft and is completely inside the $9\frac{5}{8}$ in. intermediate casing.

Example 4.1—cont'd

Solution:

From the ideal gas law,

$$\frac{P_b V_b}{z_b T_b} = \frac{P_x V_x}{z_x T_x}$$

Since the influx has migrated without expansion,

$$V_b = V_x = 260\,\text{bbls}$$

Therefore,

$$P_x = \frac{z_x T_x P_b}{z_b T_b}$$

or

$$P_x = \frac{16,712(1.581)(650)}{(1.988)(772)}$$

$$P_x = \mathbf{11,190\,psi}$$

and

$$P_s = 11,190 - 0.9048(10,200)$$

$$P_s = \mathbf{1961\,psi}$$

Analysis of the surface pressure data was in good agreement with the actual condition encountered. The surface pressure at the time that the influx was encountered at 10,200 ft was 2000 psi. The calculated surface pressure under the given conditions was 1961 psi. It is important to note that this influx was not expanded as it migrated and the surface pressure decreased significantly. Instinctively, it is anticipated that the surface pressure will increase significantly as an unexpanded influx migrates. However, under these unusual conditions, the opposite was true.

Recent research has suggested that migration analysis based upon pressure interpretations is limited due to the fact that the compressibilities of the mud, hole filter cake, and formations are not routinely considered in field analyses. However, field application of the techniques described in this chapter has proved generally successful. An increase in surface pressure is the result of the reduction in drilling mud hydrostatic above the influx as the influx migrates through the drilling mud. Field observations have generally proved consistent with the theoretical considerations described herein.

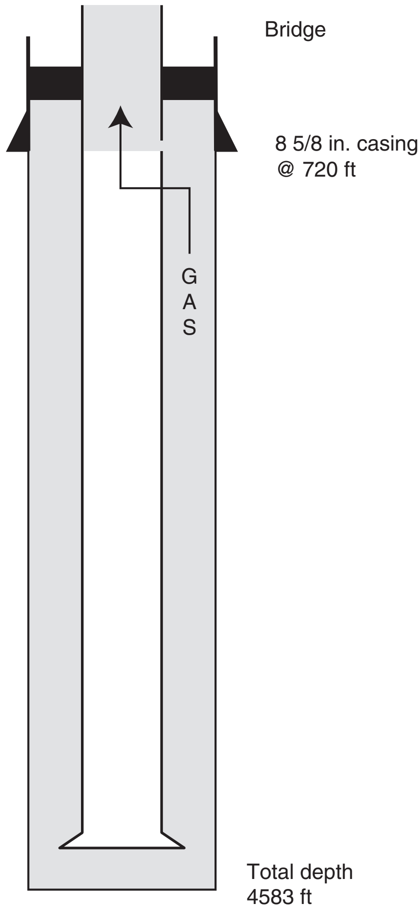


Fig. 4.6 Well with hole in the drill pipe.

Consider the wellbore schematic presented as Fig. 4.6, which depicts a blowout near Albany, Texas. As illustrated, there was a hole in the drill pipe at 980 ft and an open hole from the $8\frac{5}{8}$in. casing shoe at 720 ft to total depth at 4583 ft. After the well was killed, gas from supercharged shallow zones was migrating to the surface through the hole in the drill pipe. As a result, an opportunity to analyze the reliability of traditional calculations was presented. Further, since the substantial open-hole interval contained a variety of fluids including mud, gas, water, and cement, it was possible to observe the error-producing effects described in literature related to compressibility.

On one of many pumping operations, the gas migrated to the surface through water in the $4\frac{1}{2}$in. drill pipe in 1 h and 15 min for a migration rate of 784 ft/h. On another occasion, as the gas migrated, water was pumped in four 2 bbl increments, and the resulting change in surface pressure was recorded. The volume of water was carefully measured from the calibrated tank of a service company cement pump truck. In the $4\frac{1}{2}$in. drill pipe, 2 bbls of fresh water represents 142 ft of hydrostatic or 122 psi. On each occasion, the surface pressure declined by a measured 120 psi after 2 bbls were pumped. The increase in surface pressure was the result of the reduction in drilling mud hydrostatic above the influx as the influx migrated through the water. Therefore, it must be concluded in this case that the compressibility of the formation and fluids had no apparent effect on the ability to predict and analyze the behavior of the influx as reflected by the surface pressures.

The concepts of influx migration and rate of migration are further illustrated in Example 4.2:

Example 4.2

Given:

Wellbore schematic = Fig. 4.7
Well depth, $D = 10{,}000$ ft
Hole size, $D_h = 7\frac{7}{8}$in
Drill pipe size, $D_p = 4\frac{1}{2}$in
$8\frac{5}{8}$in. surface casing = 2000 ft
Casing internal diameter, $D_{ci} = 8.017$ in.
Fracture gradient, $F_g = 0.76$ psi/ft
Mud weight, $\rho = 9.6$ ppg
Mud gradient, $\rho_m = 0.50$ psi/ft
A kick is taken with the drill string on bottom and
Shut-in drill pipe pressure, $P_{dp} = 200$ psi
Shut-in annulus pressure, $P_a = 300$ psi
Pit level increase = 10 bbls
Capacity of the
Drill pipe casing annulus, $C_{dpca} = 0.0428$ bbl/ft
Drill pipe hole annulus, $C_{dpha} = 0.0406$ bbl/ft
Depth to top of influx = 9754 ft

Further, the rig has lost all power and is unable to displace the influx. After 1 h, the shut-in drill pipe pressure has increased to 300 psi, and the shut-in annulus pressure has increased to 400 psi.

Required:

The depth to the top of the influx after 1 h and the rate of influx migration

Continued

Example 4.2—cont'd

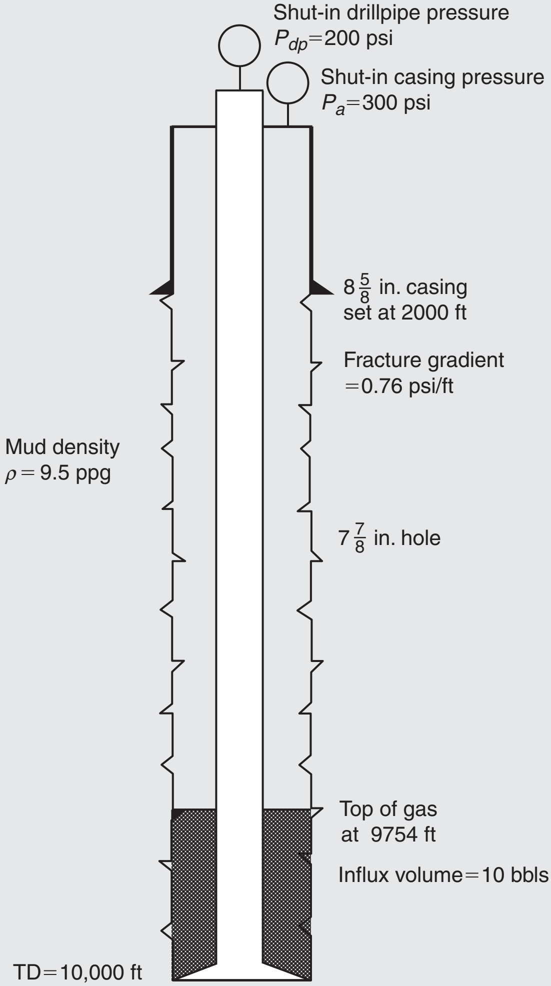


Fig. 4.7 Influx migration.

Solution:

The distance of migration, D_{mgr}, is given by Eq. (4.7):

$$D_{mgr} = \frac{\Delta P_{inc}}{0.052\rho} \tag{4.7}$$

where

ΔP_{inc} = pressure increase, psi
ρ = mud weight, ppg

Example 4.2—cont'd

$$D_{mgr} = \frac{100}{(0.052)(9.6)}$$
$$D_{mgr} = \mathbf{200\ ft}$$

The depth to the top of the influx, D_{toi}, after 1 h is

$$D_{toi} = TOI - D_{mgr} \tag{4.8}$$

where
TOI = initial top of influx, ft
D_{mgr} = distance of migration, ft

$$D_{toi} = 9754 - 200$$
$$D_{toi} = \mathbf{9554\ ft}$$

Velocity of migration, V_{mgr}, is given by

$$V_{mgr} = \frac{D_{mgr}}{\text{Time}} \tag{4.9}$$
$$V_{mgr} = \frac{200}{1}$$
$$V_{mgr} = \mathbf{200\ ft/h}$$

The condition of the well after 1 h is schematically illustrated as Fig. 4.8. After 1 h, the shut-in surface pressures have increased by 100 psi. The shut-in drill pipe pressure has increased from 200 psi to 300 psi, and the shut-in casing pressure has increased from 300 psi to 400 psi. Therefore, the drilling mud hydrostatic equivalent to 100 psi has passed from above the influx to below the influx, or the influx has migrated through the equivalent of 100 psi mud hydrostatic, which is equivalent to 200 ft of mud hydrostatic. The loss in mud hydrostatic of 100 psi has been replaced by additional shut-in surface pressure of 100 psi. Therefore, the rate of migration for the first hour is 200 ft/h.

It should not be anticipated that the rate of migration will remain constant. As the influx migrates toward the surface, the velocity normally will increase. The influx will expand, the diffused bubbles will accumulate into one large bubble, and the migration velocity will increase.

The influx could be permitted to migrate to the surface. The methodology would be exactly the same as the Driller's method at 0 bbls/min circulation rate. The drill pipe pressure would be kept constant by bleeding mud from the annulus. The casing pressure would have to be bled in small increments while noting the effect on the drill pipe pressure after a few seconds.

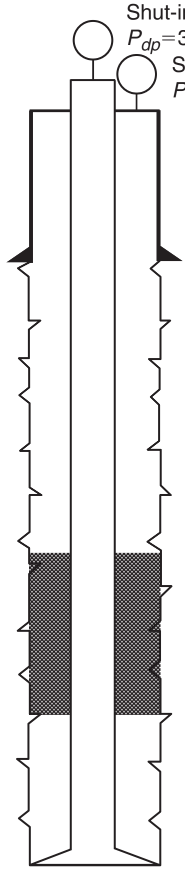


Fig. 4.8 Influx migration after 1 h.

For example, in this instance, it would not be proper to bleed 100 psi from the annulus and wait to observe the drill pipe pressure. The proper procedure would be to permit the surface pressure to build by 100 psi increments and then to bleed the casing pressure in 25 psi increments while observing the effect on the drill pipe pressure. The exact volumes of mud bled must be measured and recorded. The drill pipe pressure must be maintained at slightly over 200 psi. In that fashion, the influx could be permitted to migrate to the surface. However, once the influx reaches the surface, the procedure generally must be terminated. Bleeding influx at the surface will usually result in additional influx at the bottom of the hole.

The procedure is illustrated in Example 4.3.

Example 4.3

Given

Same conditions as Example 4.2

Required:

Describe the procedure for permitting the influx to migrate to the surface.

Solution:

The effective hydrostatic of 1 bbl of mud, P_{hem}, in the annulus is given by Eq. (4.10):

$$P_{hem} = \frac{0.052\rho}{C_{dpha}} \tag{4.10}$$

where

ρ = mud weight, ppg
C_{dpha} = annular capacity, bbl/ft

$$P_{hem} = \frac{0.052(9.6)}{0.0406}$$
$$P_{hem} = \mathbf{12.3\ psi/bbl}$$

Therefore, for each barrel of mud bled from the annulus, the minimal acceptable annulus pressure must be increased by 12.3 psi.

The Table 4.1 summarizes the procedure.

As illustrated in Fig. 4.9 and Table 4.1, the pressure on the surface is permitted to build to a predetermined value. This value should be calculated to consider the fracture gradient at the casing shoe in order that an underground blowout will not occur. In this first instance, the value is a 100 psi increase in surface pressure. After the surface pressure has built

Table 4.1 Procedure for influx migration

Time	Drill pipe pressure	Casing pressure	Volume bled	Minimum casing pressure
0900	200	300	0.00	300
1000	300	400	0.00	300
1005	275	375	0.05	301
1010	250	350	0.10	301
1015	225	325	0.15	302
1020	200	303	0.20	303
–	–	–	–	–

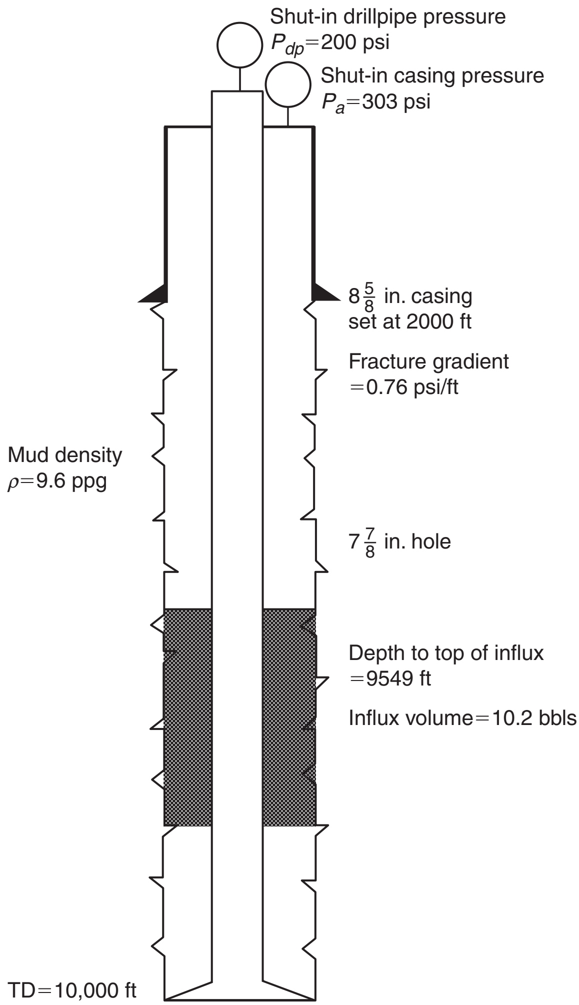


Fig. 4.9 Influx migration after bubble expansion.

100–300 psi on the drill pipe and 400 psi on the casing, the influx is expanded and the surface pressure lowered by bleeding mud from the annulus. The pressure is bled in 25 psi increments.

Due to the expansion of the influx, the drill pipe pressure will return to 200 psi, but casing pressure will not return to 300 psi. Rather, the hydrostatic of the mud released from the annulus must be replaced by the equivalent pressure at the surface. In this case, 0.20 bbls was bled from the annulus, and the drill pipe pressure returned to 200 psi. However, the casing pressure could not be lowered below 303 psi. The 3 psi additional casing pressure replaces the 0.20 bbl of mud hydrostatic.

As further illustrated in Fig. 4.9, the depth to the top of the influx after the mud has been bled from the annulus is 9549 ft. Therefore, the influx has expanded 5 ft, which was the volume formerly occupied by the 0.20 bbls of mud. Also, the influx volume has increased from 10 to 10.2 bbls.

The calculations presented in this example are based on the actual theoretical calculations. In the field, the drill pipe pressure would probably be maintained at a value in excess of the original shut-in drill pipe pressure. However, the fracture gradient at the shoe must be considered in order to ensure that no underground blowout occurs.

Influx Migration—Volumetric Procedure

Influx migration without the ability to read the drill pipe pressure represents a much more difficult situation. The influx can safely be permitted to migrate to the surface if a volumetric procedure is used. Once again, consider Eq. (2.7):

$$P_b = \rho_f h + \rho_m (D - h) + P_a$$

Expanding Eq. (2.7) gives

$$P_b = P_a + \rho_m D - \rho_m h + \rho_f h$$

The object of the procedure is to permit the influx to migrate while maintaining the bottom-hole pressure constant. Therefore, the right side of Eq. (2.7) must remain constant as the influx migrates. For any given conditions, $\rho_m D$ is constant. In addition, $\rho_f h$ is constant provided the geometry of the wellbore remains constant. To be pure theoretically, the geometry of the wellbore would have to be considered. However, to assume that the geometry is the same as on bottom is normally to err conservatively. That is, the cross-sectional area of the annulus might increase nearer the surface, thereby reducing the hydrostatic of the influx, but it almost never decreases nearer the surface. The one obvious exception is in floating drilling operations where the influx would have to migrate through a small choke line.

Therefore, in order to permit the influx to migrate while maintaining the bottom-hole pressure constant, Eq. (2.7) is reduced to

$$\text{Constant} = P_a + \text{Constant} - \rho_m h + \text{Constant}$$

If the bottom-hole pressure is to remain constant during the influx migration, any change in the mud hydrostatic due to the expansion of the influx must be offset by a corresponding increase in the annulus pressure. In this example, if 1 bbl of mud was released from the annulus, the shut-in casing pressure could not be reduced below 312 psi. If 2 bbls of mud were released, the shut-in casing pressure could not be reduced below 324 psi.

The procedure is illustrated in Example 4.4, which is the same as Example 4.3 with the exception that the drill pipe contains a float that does not permit the shut-in drill pipe pressure to be recorded.

Example 4.4

Given:

Same conditions as Example 4.3 except the drill pipe contains a float that does not permit the shut-in drill pipe pressure to be recorded. Further, the rig has lost all power and is unable to displace the influx. After 1 h, the shut-in annulus pressure has increased to 400 psi.

Required:

Describe the procedure for permitting the influx to migrate to the surface.

Solution:

The effective hydrostatic of 1 bbl of mud, P_{hem}, in the annulus is given by Eq. (4.10):

$$P_{hem} = \frac{0.052\rho}{C_{dpha}}$$

$$P_{hem} = \frac{0.052(9.6)}{0.0406}$$

$$P_{hem} = \mathbf{12.3\ psi/bbl}$$

Therefore, for each barrel of mud bled from the annulus, the minimum acceptable annulus pressure is increased by 12.3 psi.

Maximum acceptable increase in surface pressure prior to influx expansion is equal to 100 psi.

Bleed 1 bbl, but do not permit the surface pressure to fall below 312 psi.

After a cumulative volume of 1 bbl has been released, do not permit the surface pressure to fall below 324 psi.

After a cumulative volume of 2 bbls has been released, do not permit the surface pressure to fall below 336 psi.

After a cumulative volume of 3 bbls has been released, do not permit the surface pressure to fall below 348 psi. Continue in this manner until the influx reaches the surface.

When the influx reaches the surface, shut in the well.

The plan and instructions would be to permit the pressure to rise to a predetermined value considering the fracture gradient at the shoe. In this instance, a 100 psi increase is used. After the pressure had increased by

100 psi, mud would be released from the annulus. As much as 1 bbl would be released, provided that the shut-in casing pressure did not fall below 312 psi. Consider Table 4.2.

In this case, in the first step, less than 0.20 bbls would have been bled, and the casing pressure would be reduced to 312 psi. At that point, the well would be shut in, and the influx is permitted to migrate further up the hole.

When the shut-in surface pressure reached 412 psi, the procedure would be repeated. After a total of 1 bbl was bled from the well, the minimum casing pressure would be increased to 324 psi, and the instructions would be to bleed mud to a total volume of 2 bbls, but not to permit the casing pressure to fall below 324 psi.

When the shut-in surface pressure reached 424 psi, the procedure would be repeated. After a total of 2 bbls was bled from the well, the minimum casing pressure would be increased to 336 psi, and the instructions would be to bleed mud to a total volume of 3 bbls, but not to permit the casing pressure to fall below 336 psi.

For each increment of 1 bbl of mud that was bled from the hole, the minimum shut-in surface pressure that would maintain the constant bottom-hole pressure would be increased by the hydrostatic equivalent of 1 bbl of mud, which is 12.3 psi for this example. If the geometry changed as the influx migrated, the hydrostatic equivalent of 1 bbl of mud would be recalculated, and the new value is used.

Table 4.2 Volumetric procedure for influx migration

Time	Surface pressure	Volume bled	Cumulative volume bled	Minimum surface pressure
0900	300	0.00	0.00	300
1000	400	0.00	0.00	300
1005	312	0.20	0.20	312
1100	412	0.00	0.20	312
1105	312	0.20	0.40	312
1150	412	0.00	0.40	312
1155	312	0.20	0.60	312
1230	412	0.00	0.60	312
1235	312	0.25	0.85	312
1300	412	0.00	0.85	312
1305	324	0.25	1.10	324
–	–	–	–	–

Influx migration is a reality in well control operations and must be considered. Failure to consider the migration of the influx will usually result in unacceptable surface pressure, ruptured casing, or an underground blowout.

SAFETY FACTORS IN CLASSICAL PRESSURE CONTROL PROCEDURES

It is well established that the Driller's method and the wait-and-weight method are based on the classical U-tube model as illustrated in Fig. 4.1. The displacement concept for all classical procedures regardless of the name is to determine the bottom-hole pressure from the mud density and the shut-in drill pipe pressure and to keep that bottom-hole pressure constant while displacing the influx. For the conditions given in Fig. 4.7, the shut-in bottom-hole pressure would be 5200 psi. Therefore, as illustrated in Chapter two, the goal of the control procedure would be to circulate the influx out of the wellbore while maintaining the bottom-hole pressure constant at 5200 psi.

One of the most serious and frequent well control problems encountered in the industry is the inability to bring the influx to the surface without experiencing an additional influx or causing an underground blowout. In addition, in the field, difficulty is experienced starting and stopping displacement without permitting an additional influx. To address the latter problem, many have adopted "safety factor" methods.

The application of the "safety factors" arbitrarily alters the classical procedures and can result in potentially serious consequences. "Safety factors" are usually in three forms. The first is in the form of some arbitrary additional drill pipe pressure in excess of the calculated circulating pressure at the kill speed. The second is an arbitrary increase in mud density above that calculated to control the bottom-hole pressure. The third is an arbitrary combination of the two. When the term "safety factor" is used, there is generally no question about the validity of the concept. Who could question "safety"? However, arbitrary "safety factors" can have serious effects on the well control procedure and can cause the very problems that they were intended to avoid! Consider Example 4.5:

Example 4.5

Given:

Wellbore schematic = Fig. 4.7

U-tube schematic = Fig. 4.10

Example 4.5—cont'd

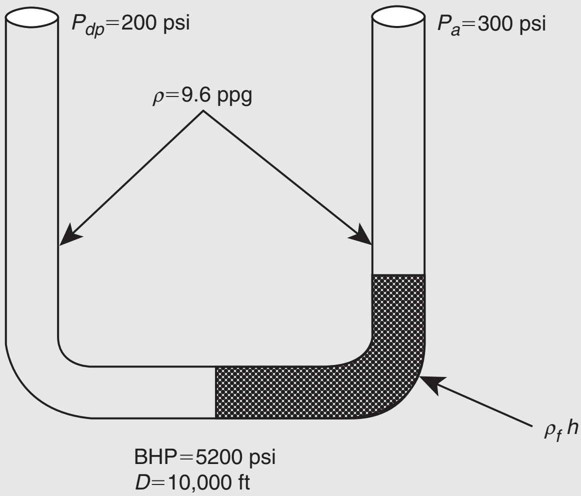


Fig. 4.10 U-tube schematic when shut-in.

Well depth, $D = 10{,}000$ ft
Hole size, $D_h = 7\frac{7}{8}$ in
Drill pipe size, $D_p = 4\frac{1}{2}$ in
$8\frac{5}{8}$in. surface casing $= 2000$ ft
Casing internal diameter, $D_{ci} = 8.017$ in.
Fracture gradient, $F_g = 0.76$ psi/ft
Fracture pressure $= 1520$ psi
Mud weight, $\rho = 9.6$ ppg
Mud gradient, $\rho_m = 0.50$ psi/ft
A kick is taken with the drill string on bottom and
Shut-in drill pipe pressure, $P_{dp} = 200$ psi
Shut-in annulus pressure, $P_a = 300$ psi
Pit level increase $= 10$ bbls
Normal circulation $= 6$ bpm at 60 spm
Kill rate $= 3$ bpm at 30 spm
Circulating pressure at kill rate, $P_{ks} = 500$ psi
Pump capacity, $C_p = 0.1$ bbl/stk
Capacity of the
  Drill pipe casing annulus, $C_{dpca} = 0.0428$ bbl/ft
  Drill pipe hole annulus, $C_{dpha} = 0.0406$ bbl/ft
  Initial displacement pressure, $P_c = 700$ psi at 30 spm
  Shut-in bottom-hole pressure, $P_b = 5200$ psi
  Maximum permissible surface pressure $= 520$ psi

Continued

Example 4.5—cont'd

Required:

1. The consequences of adding a 200 psi "safety factor" to the initial displacement pressure in the Driller's method
2. The consequences of adding a 0.5 ppg "safety factor" to the kill-mud density in the wait-and-weight method

Solution:

1. The consequence of adding a 200 psi "safety factor" to the initial displacement pressure is that the pressure on the casing is increased from 200 to 500 psi.

   The pressure at the casing shoe is increased to 1500 psi, which is perilously close to the fracture gradient. See Fig. 4.11.
2. With 10.5 ppg mud to the bit, the pressure on the left side of the U-tube is

$$P_{10000} = \rho_{m1} D$$
$$P_{10000} = 0.546(10,000)$$
$$P_{10000} = \mathbf{5460\ psi}$$

Therefore, with the weighted mud at the bit, the pressure on the right side of the U-tube is increased by **260 psi**, which would result in lost circulation at the shoe.

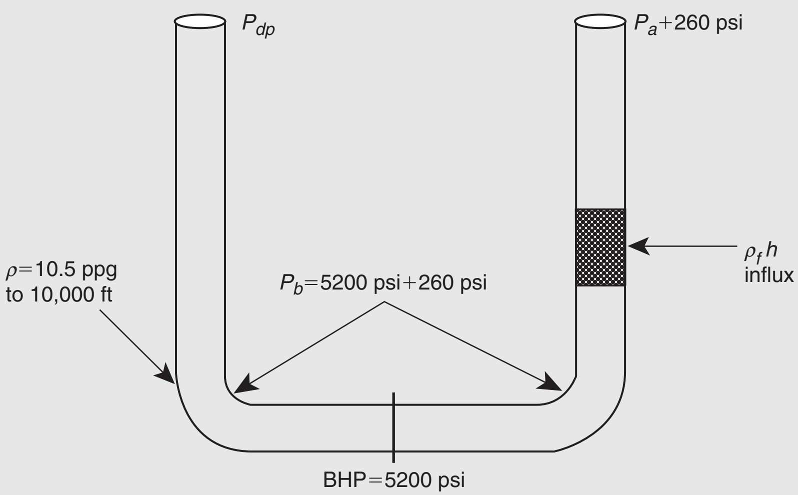


Fig. 4.11 U-tube schematic when influx is partially circulated out.

In these examples, the "safety factors" were not safety factors after all. As illustrated in Fig. 4.10, in the instance of a "safety factor" in the form of additional surface pressure, the additional pressure is added to the entire system.

The bottom-hole pressure is not being kept constant at the shut-in bottom-hole pressure as intended. Rather, it is being held constant at the shut-in bottom-hole pressure and the "safety factor," which is 5400 psi in this example. To further aggravate the situation, the "safety factor" is applied to the casing shoe.

Thanks to the "safety factor," the pressure at the casing shoe is increased from 1300 psi to 1500 psi, which is within 20 psi of the pressure necessary to cause an underground blowout. As the influx is circulated to the casing shoe, the pressure at the casing shoe increases. Therefore, under the conditions in Example 4.5, with the 200 psi "safety factor," lost circulation and a possible underground blowout would be inevitable!

In Fig. 4.11, it is illustrated that the increase in kill-mud weight to 10.5 ppg resulted in an additional 260 psi on the entire system. The bottom-hole pressure was no longer being kept constant at 5200 psi as originally conceived. It was now being kept constant at 5460 psi. This additional burden was more than the fracture gradient that was capable of withstanding. By the time that the kill mud reached the bit, the annulus pressure would be well above the maximum permissible 520 psi. Therefore, under these conditions, with the additional 0.5 ppg "safety factor," lost circulation and a possible underground blowout would be inevitable.

A kill-mud density higher than calculated by classical techniques can be used, provided that Eq. (2.11) is strictly adhered to

$$P_{cn} = P_{dp} - 0.052(\rho_1 - \rho) + \left(\frac{\rho_1}{\rho}\right) P_{ks}$$

In Eq. (2.11), any additional hydrostatic pressure resulting from the increased density is subtracted from the frictional pressure. Therefore, the bottom-hole pressure can be maintained constant at the calculated bottom-hole pressure, which is 5200 psi in this example. Following this approach, there would be no adverse effects as a result of using the 10.5 ppg mud as opposed to the 10.0 ppg mud. Further, there would be no "safety factor" in terms of pressure at the bottom of the hole greater than the calculated shut-in bottom-hole pressure.

However, there would be a "safety factor" in that the pressure at the casing shoe with 10.5 ppg mud would be lower than the pressure at the casing shoe with 10.0 ppg mud. The annulus pressure profiles are further discussed in a following section. Another advantage would be that the circulating time would be less if 10.5 ppg mud was used because the trip margin would have been included in the original circulation.

A disadvantage is that the operation would fail if it became necessary to shut in the well any time after the 10.5 ppg mud reached the bit and before the influx reached the casing shoe. In that event, the pressure at the casing shoe would exceed the fracture gradient, and an underground blowout may occur.

CIRCULATING A KICK OFF BOTTOM

All too often, a drilling report reads like this: "Tripped out of hole. Well flowing. Tripped in with 10 stands and shut in well. Shut-in pressure 500 psi. Circulated heavy mud, keeping the drill pipe pressure constant. Shut-in pressure 5000 psi."

Attempting to circulate with the bit off bottom in a kick situation has caused as many well control situations to deteriorate as any other single operation. Simply put, *there is no classical well control procedure that applies to circulating with the bit off bottom with a formation influx in the wellbore!* The reason is that the classical U-tube model does not describe the wellbore condition and is not valid in this situation.

If the bit is off bottom as illustrated in Fig. 4.12, the U-tube model becomes a Y-tube model. The drill pipe pressure can be influenced by the operations at the choke. However, the drill pipe pressure can also be affected by the wellbore condition and activity in the bottom of the Y-tube. It is not possible to know the relative effect of each factor.

Therefore, the concepts, technology, and terminology of classical well control have no meaning or application under these circumstances. The Driller's method is not valid. The wait-and-weight method is not valid. Keeping the drill pipe pressure constant has no meaning. These are valid only if the U-tube model describes the wellbore conditions.

A well can be circulated safely off bottom with a kick in the hole provided that it exhibits all the characteristics of a dead well. That is, the drill pipe pressure must remain constant, the casing pressure must remain constant, the choke size must remain constant, the circulation rate must remain constant, and the pit volume must remain constant. Continuing to circulate with any of these factors changing usually results in more serious well control problems.

CLASSICAL PROCEDURES—PLUGGED NOZZLE EFFECT

While a kick is being circulated out utilizing the Driller's method or the wait-and-weight method, it is possible for a nozzle to plug. In the event that a nozzle does plug, the choke operator would observe a sudden rise in

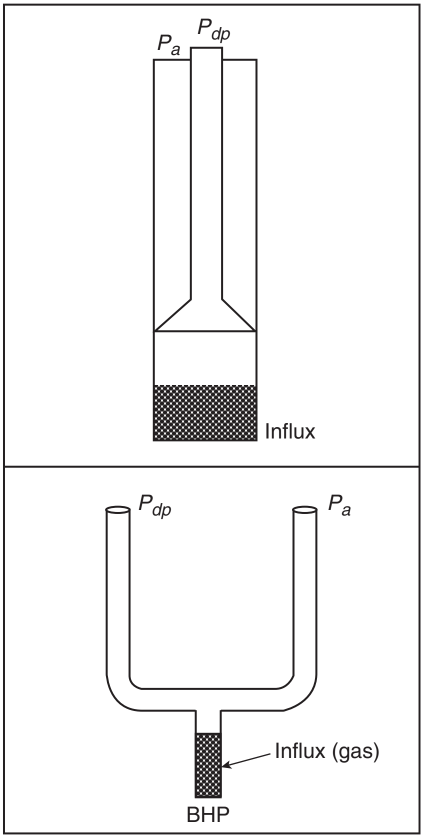


Fig. 4.12 Circulating off bottom alters U-tube model.

circulating drill pipe pressure with no corresponding increase in annulus pressure. The normal reaction would be for the choke operator to open the choke in an attempt to keep the drill pipe pressure constant. Of course, when the choke is opened, the well becomes underbalanced, and additional influx is permitted. Unchecked, the well will eventually unload, and a blowout will follow.

A plugged nozzle does not alter the U-tube model. The U-tube model and classical pressure control procedures are still applicable. What have been altered are the frictional pressure losses in the drill string. The circulating pressure at the kill speed has been increased as a result of the plugged nozzle. The best procedure to follow when the drill pipe pressure increases suddenly is to shut in the well and restart the procedure as outlined in Chapter two for either the wait-and-weight method or the Driller's method.

Modern polycrystalline diamond compact (PDC) bits, generally contain at least six large nozzles. At pump rates used to kill a well, a plugged nozzle would not result in a pressure increase of more than 10–20 psi. A single plugged nozzle is going to be difficult to detect.

CLASSICAL PROCEDURES—DRILL STRING WASHOUT EFFECT

When a washout occurs in the drill string, a loss in drill pipe pressure will be observed with no corresponding loss in annulus pressure. The only alternative is to shut in the well and analyze the problem. If the Driller's method is being used, the analysis is simplified. As illustrated in Fig. 4.13A, if the well is shut in and the influx is below the washout, the shut-in drill pipe pressure and the shut-in annulus pressure will be equal. Under these conditions, the U-tube model is not applicable, and no classical procedure is appropriate.

There are several alternatives. Probably the best general alternative is to permit the influx to migrate to the surface pursuant to the prior discussions and, once the influx has reached the surface, circulate it out. Another alternative is to locate the washout, strip out to the washout, repair the bad joint or connection, strip in the hole to bottom, and resume the well control procedure.

If the Driller's method is being utilized when the washout occurs, the well is shut in, and the influx is above the washout as illustrated in Fig. 4.13B, the shut-in drill pipe pressure will be less than the shut-in annulus pressure. Under these conditions, the U-tube model is applicable, and the influx can be circulated out by continuing the classical Driller's method as outlined in Chapter two.

The frictional pressure losses in the drill string have been altered, and the circulating pressure at the kill speed that was originally established is no longer applicable. A new circulating pressure at the kill speed must be established as outlined in Chapter two. That is, hold the casing pressure constant while bringing the pump to speed. Read the new drill pipe pressure and keep that drill pipe pressure constant, while the influx is circulated to the surface.

If the wait-and-weight method is being used, the analysis is considerably more complicated because, as illustrated in Fig. 4.13C and D, the kill-weight mud has been introduced to the system. Therefore, the differences in mud hydrostatic must be included in the analysis to determine the relationship between the shut-in drill pipe pressure and the shut-in casing pressure. Since

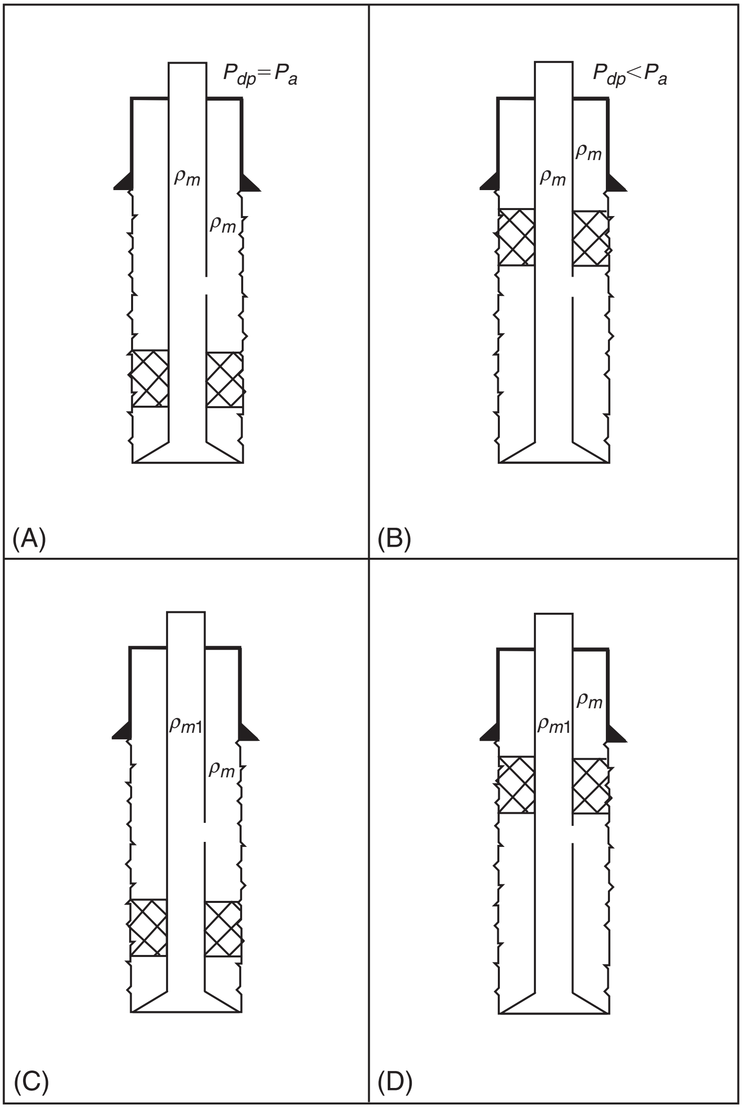


Fig. 4.13 (A) Driller's method, influx below washout, (B) Driller's method, influx above washout, (C) wait-and-weight method, influx below washout (D) wait-and-weight method, influx above washout.

the depth of the washout is not usually known, it may not be possible to determine a reliable relationship between the shut-in drill pipe pressure and the shut-in casing pressure. Once the analysis is performed, the alternatives are the same as those discussed for the Driller's method.

DETERMINATION OF SHUT-IN DRILL PIPE PRESSURES

Generally, the drill pipe pressure will stabilize within minutes after shut-in and is easily determined. In some instances, the drill pipe pressure may never build to reflect the proper bottom-hole pressure, particularly in cases of long open-hole intervals at or near the fracture gradient coupled with very low productivities. When water is used as the drilling fluid, gas migration can be rapid, thereby masking the shut-in drill pipe pressure. In these instances, a good knowledge of anticipated bottom-hole pressures and anticipated drill pipe pressures is beneficial in recognizing and identifying problems and providing a base for pressure control procedures.

A float in the drill string complicates the determination of the drill pipe pressure; however, it can be readily determined by pumping slowly on the drill pipe and monitoring both the drill pipe and annulus pressure. When the annulus pressure first begins to increase, the drill pipe pressure at that instant is the shut-in drill pipe pressure.

Another popular procedure is to pump through the float for a brief moment, holding the casing pressure constant, and then shut in with the original annulus pressure, thereby trapping the drill pipe pressure on the stand pipe gauge. An additional technique is to bring the pump to kill speed and compare the circulating pressure with the prerecorded circulating pressure at the kill rate with the difference being the drill pipe pressure. Still another alternative is to use a flapper-type float with a small hole drilled through the flapper that permits pressure reading but not significant flow.

DETERMINATION OF THE TYPE OF FLUID THAT ENTERED THE WELLBORE

Of primary interest in the determination of fluid types is whether gas has entered the wellbore. If only liquid is present, control is simplified. An accurate measurement of increase in pit level is mandatory if a reliable determination is to be made. Example 4.6 illustrates the calculation:

Example 4.6

Given:

Wellbore schematic = Fig. 4.7

Well depth, $D = 10{,}000$ ft

Hole size, $D_h = 7\frac{7}{8}$ in

Drill pipe size, $D_p = 4\frac{1}{2}$ in

$8\frac{5}{8}$ in. surface casing = 2000 ft

Casing internal diameter, $D_{ci} = 8.017$ in.

Fracture gradient, $F_g = 0.76$ psi/ft

Example 4.6—cont'd

Mud weight, $\rho = 9.6$ ppg
Mud gradient, $\rho_m = 0.50$ psi/ft
A kick is taken with the drill string on bottom and
Shut-in drill pipe pressure, $P_{dp} = 200$ psi
Shut-in annulus pressure, $P_a = 300$ psi
Pit level increase = 10 bbls
Capacity of
Drill pipe hole annulus, $C_{dpha} = 0.0406$ bbl/ft

Required:

Determine density of the fluid entering the wellbore.

Solution:

From Eq. (2.6)

$$P_b = \rho_m D + P_{dp}$$

From Eq. (2.7)

$$P_b = \rho_f h + \rho_m (D - h) + P_a$$

The height of the bubble, h, is given by Eq. (3.7):

$$h = \frac{\text{Influx Volume}}{C_{dpha}}$$
$$h = \frac{10}{0.0406}$$
$$h = \mathbf{246\ ft}$$

Solving Eqs. (2.6), (2.7) simultaneously gives

$$\rho_m D + P_{dp} = \rho_f h + \rho_m (D - h) + P_a$$

The only unknown is ρ_f; therefore substituting and solving yield

$$\rho_f (246) = 0.5(10,000) + 200 - 0.5(10,000 - 246) - 300$$
$$\rho_f = \frac{23}{246}$$
$$\rho_f = \mathbf{0.094\ psi/ft}$$

Confirmation can be attained utilizing Eq. (3.5):

$$\rho_f = \frac{S_g P_b}{53.3 z_b T_b}$$
$$\rho_f = \frac{0.6(5200)}{53.3(1.1)(620)}$$
$$\rho_f = \mathbf{0.0858\ psi/ft}$$

Continued

Example 4.6—cont'd

Therefore, since the calculated influx gradient is approximately the same as the fluid gradient determined using an assumed influx specific gravity of 0.6, the fluid in the wellbore is gas. Natural gas will usually have a fluid gradient of 0.15 psi/ft or less, while brine water has a density of approximately 0.45 psi/ft, and oil has a density of approximately 0.3 psi/ft. Obviously, combinations of gas, oil, and water can have a gradient anywhere between 0.1 and 0.45 psi/ft.

FRICTIONAL PRESSURE LOSSES

Frictional pressure losses inside the drill string are usually measured, while frictional pressure losses in the annulus in conventional operations are usually ignored. However, in any kill operation, well-site personnel should have the means and ability to calculate the circulating pressure losses.

For laminar flow in the annulus, the frictional pressure loss is given by Eq. (4.11) for the power-law fluid model:

$$P_{fla} = \left[\left(\frac{2.4\overline{v}}{D_h - D_p}\right)\left(\frac{2n+1}{3n}\right)\right]^n \frac{Kl}{300\left(D_h - D_p\right)} \tag{4.11}$$

For laminar flow inside pipe, the frictional pressure loss is given by Eq. (4.12):

$$P_{fli} = \left[\left(\frac{1.6\overline{v}}{D}\right)\left(\frac{3n+1}{4n}\right)\right]^n \frac{Kl}{300} \tag{4.12}$$

For turbulent flow in the annulus, the frictional pressure loss is given by Eq. (4.13):

$$P_{fta} = \frac{7.7(10^{-5})\rho^{0.8}Q^{1.8}(PV)^{0.2}l}{\left(D_h - D_p\right)^3\left(D_h + D_p\right)^{1.8}} \tag{4.13}$$

For turbulent flow inside pipe, the frictional pressure loss is given by Eq. (4.14):

$$P_{fti} = \frac{7.7(10^{-5})\rho^{0.8}Q^{1.8}(PV)^{0.2}l}{D_i^{4.8}} \tag{4.14}$$

For flow through the bit, the pressure loss is given by Eq. (4.15):

$$P_{bit} = 9.14\left(10^{-5}\right)\frac{\rho Q^2}{A_n^2} \tag{4.15}$$

where

P_{bit} = bit pressure losses, psi
P_{fla} = laminar annular losses, psi
P_{fta} = turbulent annular losses, psi
P_{fli} = laminar losses inside pipe, psi
P_{fti} = turbulent losses inside pipe, psi
$\overline{v}$ = average velocity, fpm
D_h = hole diameter, in
D_p = pipe outside diameter, in
D_i = pipe inside diameter, in
ρ = mud weight, ppg
Θ_{600} = viscometer reading at 600 rpm, $\frac{\text{lb}_f}{100\text{ft}^2}$
Θ_{300} = viscometer reading at 300 rpm, $\frac{\text{lb}_f}{100\text{ft}^2}$

$$n = 3.32 \log\left(\frac{\Theta_{600}}{\Theta_{300}}\right) \tag{4.16}$$

$$K = \frac{\Theta_{300}}{511^n} \tag{4.17}$$

l = Length, ft
Q = Volume rate of flow, gpm
PV = Plastic viscosity, centipoise

$$= \Theta_{600} - \Theta_{300} \tag{4.18}$$

A_n = Total nozzle area, in.^{2}

Flow inside the drill string is usually turbulent, while flow in the annulus is normally laminar. When the flow regime is now known, make the calculations assuming both flow regimes. The calculation resulting in the greater value for frictional pressure loss is correct and defines the flow regime.

Example 4.7 illustrates a calculation.

Example 4.7

Given:

Wellbore schematic = Fig. 4.7
Well depth, D = 10,000 ft
Hole size, $D_h = 7\frac{7}{8}$ in
Drill pipe size, $D_p = 4\frac{1}{2}$ in
$8\frac{5}{8}$ in. surface casing = 2000 ft

Continued

Example 4.7—cont'd

Casing internal diameter, $D_{ci} = 8.017$ in.
Mud weight, $\rho = 9.6$ ppg
Mud gradient, $\rho_m = 0.50$ psi/ft
Normal circulation rate = 6 bpm at 60 spm
Kill circulation rate = 3 bpm at 30 spm
Capacity of
Drill pipe hole annulus, $C_{dpha} = 0.0406$ bbl/ft

$$\Theta_{600} = 25 \frac{\mathrm{lb_f}}{100\,\mathrm{ft}^2}$$
$$\Theta_{300} = 15 \frac{\mathrm{lb_f}}{100\,\mathrm{ft}^2}$$

Required:

The frictional pressure loss in the annulus assuming laminar flow

Solution:

$$\bar{v} = \frac{Q}{Area}$$

$$\bar{v} = \frac{126\left(\frac{\mathrm{gal}}{\mathrm{min}}\right)}{\frac{\pi}{4}\left(7.875^2 - 4.5^2\right)\left(\mathrm{in}^2\right)}\left(\frac{144\frac{\mathrm{in}^2}{\mathrm{ft}^2}}{7.48\frac{\mathrm{gal}}{\mathrm{ft}^3}}\right)$$

$$\bar{v} = \mathbf{74\,fpm}$$

$$n = 3.32\log\left(\frac{\Theta_{600}}{\Theta_{300}}\right)$$

$$n = 3.32\log\left(\frac{25}{15}\right)$$

$$n = \mathbf{0.74}$$

$$K = \frac{\Theta_{300}}{511^n}$$

$$K = \frac{15}{511^{0.74}}$$

$$K = \mathbf{0.15}$$

$$P_{fla} = \left[\left(\frac{2.4\bar{v}}{D_h - D_p}\right)\left(\frac{2n+1}{3n}\right)\right]^n \frac{Kl}{300\left(D_h - D_p\right)}$$

$$P_{fla} = \left[\left(\frac{2.4(74)}{7.875 - 4.5}\right)\left(\frac{2(0.74)+1}{3(0.74)}\right)\right]^{0.74} \times \frac{(0.15)(10,000)}{300(7.875 - 4.5)}$$

$$P_{fla} = \mathbf{30\,psi}$$

In this example, the frictional pressure loss in the annulus is only 30 psi. However, it is important to understand that the frictional pressure loss in the annulus is neglected in classical pressure control procedures. Therefore, the actual bottom-hole pressure during a displacement procedure is greater than the calculated pressure by the *value* of the frictional pressure loss in the annulus. In this case, the bottom-hole pressure would be held constant at 5230 psi during the Driller's method and the wait-and-weight method. In the final analysis, the frictional pressure loss in the annulus is a true "safety factor."

In deep wells with small annular areas, the frictional pressure loss in the annulus could be very significant and should be determined. Theoretically, if the fracture gradient at the shoe is a problem, the circulating pressure at the kill speed could be reduced by the frictional pressure loss in the annulus. For instance, using the Driller's method in this example, the circulating pressure at the kill speed could be reduced from 700 psi at 30 spm to 670 psi at 30 spm. The bottom-hole pressure would remain constant at 5200 psi, and there would be no additional influx during displacement.

ANNULUS PRESSURE PROFILES WITH CLASSICAL PROCEDURES

The annulus pressure profile and analysis of the pressures at the casing shoe during classical pressure control procedures provide essential insight into any well control operation. Further, the determination of the gas volume at the surface and the time sequence for events are essential to the understanding and execution of classical pressure control procedures. Those responsible for killing the well must be informed of what is to be expected and the appropriate sequence of events.

As will be illustrated in the following example, the annulus pressure will increase by almost three times during the displacement procedure, and at the end, dry gas will be vented for 20 min. Those with little experience may not expect or be mentally prepared for 20 min of dry gas and might be tempted to alter an otherwise sound and prudent procedure. Furthermore, confidence might be shaken by the reality of an additional 50 bbl increase in pit level. In any well control procedure, the more complete and thorough the plan, the better the chance of an expeditious and successful completion.

One of the primary problems in well control is that of circulating a kick to the surface after the well has been shut in without losing circulation and causing an underground blowout. Analysis of the annulus pressure behavior prior to initiating the displacement procedure would permit the evaluation and consideration of alternatives and probably prevent a disaster.

The annulus pressure profile during classical pressure control procedures for an influx of gas can be calculated for both the Driller's method and the wait-and-weight method. For the Driller's method, consider Fig. 4.14. The pressure, P_x, at the top of the influx at any point in the annulus X ft from the surface is given by Eq. (4.19):

$$P_x = P_a + \rho_m X \tag{4.19}$$

With the influx X ft from the surface, the surface pressure on the annulus is given by Eq. (4.20):

$$P_a = P_b - \rho_m (D - h_x) - P_f \tag{4.20}$$

where

P_x = pressure at depth X, psi

P_a = annulus pressure, psi

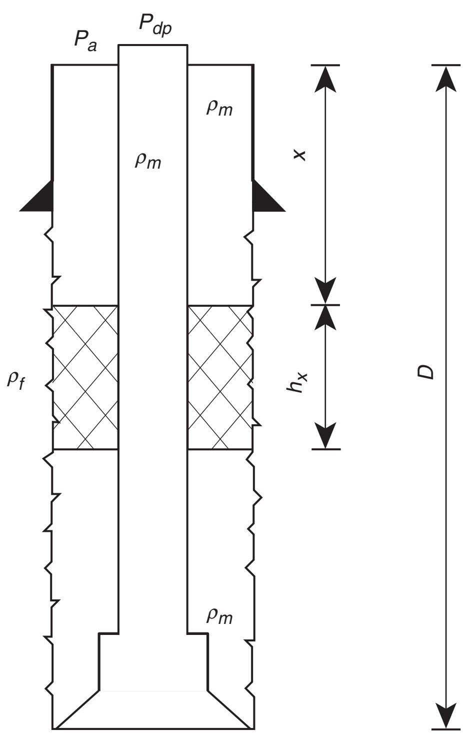


Fig. 4.14 Wellbore schematic for the Driller's method.

P_b = bottom-hole pressure, psi
ρ_m = mud gradient, psi/ft
D = well depth, ft
h_x = height of the influx at depth X, ft
P_f = pressure exerted by the influx at depth X, psi

and pursuant to the ideal gas law:

$$h_x = \frac{P_b z_x T_x A_b}{P_x z_b T_b A_x} h_b \tag{4.21}$$

b denotes bottom-hole conditions
x denotes conditions at depth X

The density of the influx is given by Eq. (3.5):

$$\rho_f = \frac{S_g P_b}{53.3 z_b T_b}$$

Substituting and solving yield the Eq. (4.22), which is an expression for the pressure at the top of the influx when it is any distance X from the surface when the Driller's method is being used:

$$P_{xdm} = \frac{B}{2} + \left[\frac{B^2}{4} + \frac{P_b \rho_m z_x T_x h_b A_b}{z_b T_b A_x}\right]^{\frac{1}{2}} \tag{4.22}$$

$$B = P_b - \rho_m (D - X) - P_f \frac{A_b}{A_x} \tag{4.23}$$

where

b = conditions at the bottom of the well
x = conditions at X
X = distance from surface to top of influx, ft
D = depth of well, ft
P_a = annular pressure, psi
ρ_m = mud gradient, psi/ft
P_b = bottom-hole pressure, psi
P_f = hydrostatic of influx, psi
z = compressibility factor
T = temperature, °R
A = annular area, in.^{2}
S_g = specific gravity of gas

Pursuant to analysis of Fig. 4.15, for the wait-and-weight method, the pressure at X is also given by Eq. (4.18). However, the expression for the pressure on the annulus becomes Eq. (4.24):

$$P_a = P_b - \rho_{m1}(D - X - h_x - l_{vds}) - \rho_m (l_{vds} + X) - P_f \frac{A_b}{A_x} \tag{4.24}$$

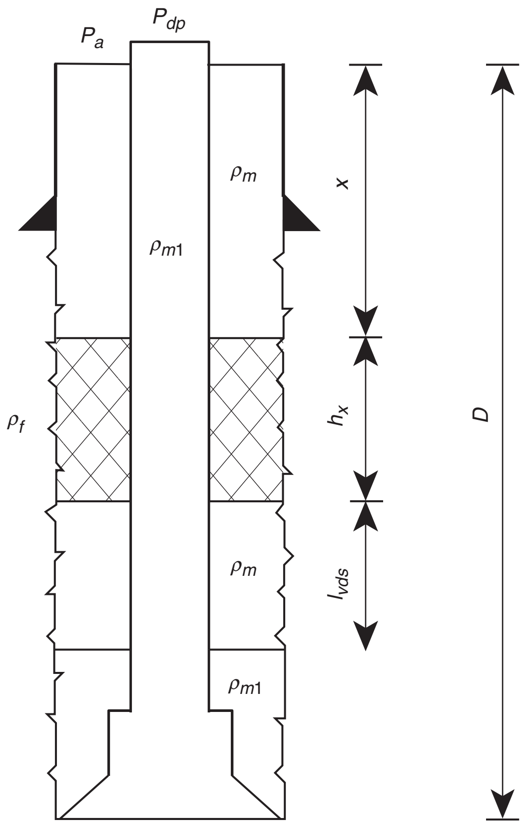


Fig. 4.15 Wellbore schematic for wait-and-weight method.

where

ρ_{m1} = kill-mud gradient, psi/ft

l_{vds} = length of drill string volume in annulus, ft

Solving Eqs. (3.5), (4.19), (4.21), (4.24) simultaneously results in Eq. (4.25), which is an expression for the pressure at the top of the influx at any distance X from the surface when the wait-and-weight method of displacement is being used:

$$P_{xww} = \frac{B_1}{2} + \left[\frac{B_1^2}{4} + \frac{P_b \rho_{m1} z_x T_x h_b A_b}{z_b T_b A_x}\right]^{\frac{1}{2}} \tag{4.25}$$

$$B_1 = P_b - \rho_{m1}(D - X) - P_f \frac{A_b}{A_x} + l_{vds}(\rho_{m1} - \rho_m) \tag{4.26}$$

Eq. (4.22) can be used to calculate the pressure at the top of the gas bubble at any point in the annulus X distance from the surface, assuming there is no change in mud weight (Driller's method). Similarly, Eq. (4.25) can be used to calculate the pressure at the top of the gas bubble at any point in the annulus X distance from the surface, assuming that the gas bubble is displaced with weighted, ρ_{m1}, mud (wait-and-weight method).

Depending on drill string geometry, the maximum pressure at any point in the annulus will generally occur when the bubble first reaches that point. The exception occurs when the drill collars are sufficiently larger than the drill pipe to cause a significant shortening of the influx as it passes from the drill-collar annulus to the drill pipe annulus. In that instance, the pressure in the annulus will be lower than the initial shut-in annulus pressure until the influx has expanded to a length equal to its original length around the drill collars. From that point upward, the pressure in the annulus at the top of the influx will be greater than when the well was first shut in.

Example 4.8 illustrates the use of Eqs. (4.22), (4.25) along with the significance and importance of the calculations:

Example 4.8

Given:

Wellbore schematic = Fig. 4.7
Well depth, $D = 10{,}000$ ft
Hole size, $D_h = 7\frac{7}{8}$ in
Drill pipe size, $D_p = 4\frac{1}{2}$ in
$8\frac{5}{8}$ in. surface casing = 2000 ft
Casing internal diameter, $D_{ci} = 8.017$ in.
Fracture gradient, $F_g = 0.76$ psi/ft
Fracture pressure = 1520 psi
Mud weight, $\rho = 9.6$ ppg
Mud gradient, $\rho_m = 0.50$ psi/ft
A kick is taken with the drill string on bottom and
Shut-in drill pipe pressure, $P_{dp} = 200$ psi
Shut-in annulus pressure, $P_a = 300$ psi
Pit level increase = 10 bbls
Kill-mud weight, $\rho_1 = 10$ ppg
Kill-mud gradient, $\rho_{m1} = 0.52$ psi/ft
Normal circulation = 6 bpm at 60 spm
Kill rate = 3 bpm at 30 spm

Continued

Example 4.8—cont'd

Circulating pressure at kill rate, $P_{ks} = 500$ psi
Pump capacity, $C_p = 0.1$ bbl/stk
Capacity of the
Drill pipe (inside), $C_{dpi} = 0.0142$ bbl/ft
Drill pipe casing annulus, $C_{dpca} = 0.0428$ bbl/ft
Drill pipe hole annulus, $C_{dpha} = 0.0406$ bbl/ft
Initial displacement pressure, $P_c = 700$ psi at 30 spm
Shut-in bottom-hole pressure, $P_b = 5200$ psi
Maximum permissible surface pressure = 520 psi
Ambient temperature = 60°F
Geothermal gradient = 1.0°/100 ft
$\rho_f h = P_f = 23$ psi
$h_b = 246$ ft
Annular area, $A_b = 32.80$ in.^{2}

Required:

A. Assuming the Driller's method of displacement
1. The pressure at the casing seat when the well is first shut in
2. The pressure at the casing seat when the top of the gas bubble reached that point
3. The annulus pressure when the gas bubble first reaches the surface
4. The height of the gas bubble at the surface
5. The pressure at the casing seat when the gas bubble reaches the surface
6. The total pit volume increase with the influx at the surface
7. The surface annulus pressure profile during displacement using the Driller's method

B. Using the wait-and-weight method of displacement
1. The pressure at the casing seat when the well is first shut in
2. The pressure at the casing seat when the top of the gas bubble reached that point
3. The annulus pressure when the gas bubble first reaches the surface
4. The height of the gas bubble at the surface
5. The pressure at the casing seat when the gas bubble reaches the surface
6. The total pit volume increase with the influx at the surface
7. The surface annulus pressure profile during displacement using the Driller's method
8. The rate at which barite must be mixed and the minimum barite required

Example 4.8—cont'd

C. Compare the two procedures

D. The significance of 600 ft of 6 in. drill collars on the annulus pressure profile

Solution:

A. **1.** The pressure at the casing shoe at 2000 ft when the well is first shut in is given by Eq. (4.19):

$$P_x = P_a + \rho_m X$$
$$P_{2000} = 300 + 0.5(2000)$$
$$P_{2000} = \mathbf{1300\ psi}$$

2. For the Driller's method of displacement, the pressure at the casing seat at 2000 ft when the top of the influx reaches that point is given by Eq. (4.22):

$$P_{xdm} = \frac{B}{2} + \left[\frac{B^2}{4} + \frac{P_b \rho_m z_x T_x h_b A_b}{z_b T_b A_x}\right]^{\frac{1}{2}}$$
$$B = P_b - \rho_m (D - X) - P_f \frac{A_b}{A_x}$$
$$B = 5200 - 0.5(10,000 - 2000) - 23\left[\frac{32.80}{32.80}\right]$$
$$B = \mathbf{1177}$$
$$P_{2000dm} = \frac{1177}{2} + \frac{1177^2}{4} + \frac{5200(0.5)(0.811)(540)(246)(32.80)}{(620)(1.007)(32.80)}\Bigg]^{\frac{1}{2}}$$
$$P_{2000dm} = \mathbf{1480\ psi}$$

3. For the Driller's method of displacement, the annulus pressure when the gas bubble first reaches the surface may be calculated using Eq. (4.22) as follows:

$$P_{xdm} = \frac{B}{2} + \left[\frac{B^2}{4} + \frac{P_b \rho_m z_x T_x h_b A_b}{z_b T_b A_x}\right]^{\frac{1}{2}}$$
$$B = P_b - \rho_m (D - X) - P_f \frac{A_b}{A_x}$$
$$B = 5200 - 0.5(10,000 - 0) - 23$$
$$B = \mathbf{177}$$

Continued

Example 4.8—cont'd

$$A_0 = \left(\frac{\pi}{4}\right)\left(8.017^2 - 4.5^2\right)$$

$$A_0 = 34.58\,\text{in.}^2$$

$$P_{0dm} = \frac{177}{2} + \left[\frac{177^2}{4} + \frac{5200(0.5)(0.875)(520)(246)(32.80)}{(620)(1.007)(34.58)}\right]^{\frac{1}{2}}$$

$$P_{0dm} = \mathbf{759\,psi}$$

4. The height of the gas bubble at the surface can be determined using Eq. (4.21):

$$h_x = \frac{P_b z_x T_x A_b}{P_x z_b T_b A_x} h_b$$

$$h_0 = \frac{5200(0.875)(520)(32.80)}{759(1.007)(620)(34.58)}(246)$$

$$h_0 = \mathbf{1165\,ft}$$

5. The pressure at the casing seat when the influx reaches the surface may be calculated by adding the annulus pressure to the mud and influx hydrostatics as follows:

$$P_{2000} = P_{0dm} + P_f \frac{A_b}{A_0} + \rho_m(2000 - h_0)$$

$$P_{2000} = 759 + 23\left[\frac{32.80}{34.58}\right] + 0.50(2000 - 1165)$$

$$P_{2000} = \mathbf{1198\,psi}$$

6. The total pit volume increase with the influx at the surface. From part 4, the length of the influx when it reaches the surface is 1165 ft:

$$\text{Total pit gain} = h_0 C_{dpca}$$

$$\text{Total pit gain} = (1165)(0.0428)$$

$$\text{Total pit gain} = \mathbf{50\,bbls}$$

7. The surface annulus pressure profile during displacement using the Driller's method.

Example calculation, from part 2 with the top of the influx at 2000 ft, the pressure at 2000 ft is calculated to be

$$P_{2000dm} = \mathbf{1480\,psi}$$

With the top of the influx at 2000 ft, the surface annulus pressure is

Example 4.8—cont'd

$$P_x = P_a + \rho_m X$$

$$P_0 = 1480 - 0.50(2000)$$

$$P_0 = \mathbf{480\ psi}$$

The surface annulus pressure profile is summarized in Table 4.3 and illustrated as Fig. 4.16.

Table 4.3 Surface annulus pressures—Driller's method

Depth to top of bubble, ft	Volume pumped, bbl	Annular pressure, psi
9754	0	300
9500	10	301
9000	30	303
8500	50	306
8000	69	310
7500	89	313
7000	109	318
6500	128	323
6000	148	329
5500	167	336
5000	186	346
4500	205	357
4000	224	371
3500	242	389
3000	260	412
2500	277	442
2000	294	480
1500	311	517
1000	326	579
500	340	659
0	353	759

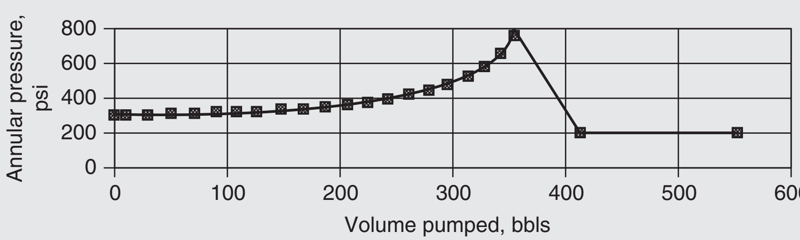


Fig. 4.16 Annular pressure profile, Driller's method.

Continued

Example 4.8—cont'd

B. **1.** The pressure at the casing shoe at 2000 ft when the well is first shut in is the same for both the Driller's method and the wait-and-weight method:

$$P_{2000} = \mathbf{1300\ psi}$$

2. For the wait-and-weight method, the pressure at the casing seat at 2000 ft when the top of the influx reaches that point is given by Eq. (4.25):

$$P_{xww} = \frac{B_1}{2} + \left[\frac{B_1^2}{4} + \frac{P_b \rho_{m1} z_x T_x h_b A_b}{z_b T_b A_x}\right]^{\frac{1}{2}}$$

$$B_1 = P_b - \rho_{m1}(D - X) - P_f \frac{A_b}{A_x} + l_{vds}(\rho_{m1} - \rho_m)$$

$$B_1 = 5200 - 0.52(10,000 - 2000) - 23\left(\frac{32.80}{32.80}\right) + \left(\frac{142}{0.0406}\right)(0.52 - 0.50)$$

$$B_1 = \mathbf{1087}$$

$$P_{2000ww} = \frac{1087}{2} + \left[\frac{1087^2}{4} + \frac{5200(0.52)(0.816)(540)(246)(32.80)}{(620)(1.007)(32.80)}\right]^{\frac{1}{2}}$$

$$P_{2000ww} = \mathbf{1418\ psi}$$

3. For the wait-and-weight method of displacement, the annulus pressure when the gas bubble first reaches the surface may be calculated using Eq. (4.25) as follows:

$$P_{xww} = \frac{B_1}{2} + \left[\frac{B_1^2}{4} + \frac{P_b \rho_{m1} z_x T_x h_b A_b}{z_b T_b A_x}\right]^{\frac{1}{2}}$$

$$B_1 = P_b - \rho_{m1}(D - X) - P_f \frac{A_b}{A_x} + l_{vds}(\rho_{m1} - \rho_m)$$

$$B_1 = 5200 - 0.52(10,000 - 0) - 23\left(\frac{32.80}{34.58}\right) + \left(\frac{142}{0.0406}\right)(0.52 - 0.50)$$

$$B_1 = \mathbf{48}$$

Example 4.8—cont'd

$$P_{0ww} = \frac{48}{2} + \left[\frac{48^2}{4} + \frac{5200(0.52)(0.883)(520)(246)(32.80)}{(620)(1.007)(34.58)}\right]^{\frac{1}{2}}$$

$$P_{0ww} = \mathbf{706\,psi}$$

4. The height of the gas bubble at the surface can be determined using Eq. (4.21):

$$h_x = \frac{P_b z_x T_x A_b}{P_x z_b T_b A_x} h_b$$
$$h_0 = \frac{5200(0.883)(520)(32.80)}{706(1.007)(620)(34.58)}(246)$$
$$h_0 = \mathbf{1264\,ft}$$

5. The pressure at the casing seat when the influx reaches the surface may be calculated by adding the annulus pressure to the mud and influx hydrostatics as follows:

$$P_{2000} = P_{0ww} + P_f \frac{A_b}{A_0} + \rho_m(2000 - h_0)$$
$$P_{2000} = 706 + 23\left[\frac{32.80}{34.58}\right] + 0.50(2000 - 1264)$$
$$P_{2000} = \mathbf{1096\,psi}$$

6. The total pit volume increase with the influx at the surface. From part 4, the length of the influx when it reaches the surface is 1264 ft:

$$\text{Total pit gain} = h_0 C_{dpca}$$
$$\text{Total pit gain} = (1264)(0.0428)$$
$$\text{Total pit gain} = \mathbf{54\,bbls}$$

7. The surface annulus pressure profile during displacement using the wait-and-weight method.

Example calculation, from part 2 with the top of the influx at 2000 ft, the pressure at 2000 ft is calculated to be

$$P_{2000ww} = \mathbf{1418\,psi}$$

With the top of the influx at 2000 ft, the surface annulus pressure is given by Eq. (4.19):

$$P_x = P_a + \rho_m X$$
$$P_0 = 1418 - 0.50(2000)$$
$$P_0 = \mathbf{418\,psi}$$

Continued

Example 4.8—cont'd

The surface annulus pressure profile is summarized in Table 4.4 and illustrated as Fig. 4.17.

8. The rate at which barite must be mixed and the minimum barite required:

Table 4.4 Surface annulus pressures—wait-and-weight method

Depth to top of bubble, ft	Volume pumped, bbl	Annular pressure, psi
9754	0	300
9500	10	301
9000	30	303
8500	50	306
8000	69	310
7500	89	313
7000	109	318
6500	128	323
6000	148	326
5500	167	323
5000	186	323
4500	205	325
4000	223	331
3500	241	341
3000	259	358
2500	276	382
2000	293	416
1500	309	450
1000	324	513
500	337	596
0	353	706

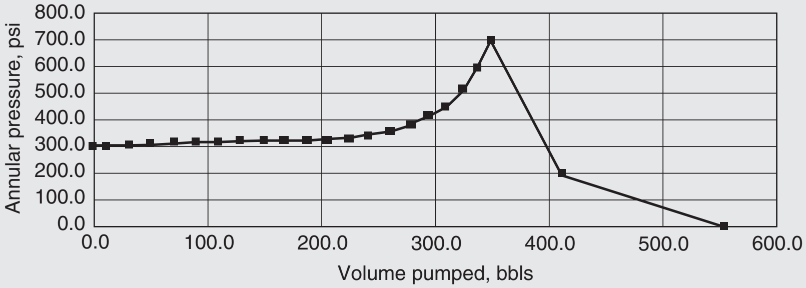


Fig. 4.17 Annular pressure profile, wait-and-weight method.

Example 4.8—cont'd

$$X' = 350 \times S_m \left[\frac{W_2 - W_1}{(S_m \times 8.33) - W_2} \right] \tag{4.27}$$

where
X' = amount of barite, lbs barite/bbl mud
W_2 = final mud weight, ppg
W_1 = initial mud weight, ppg
S_m = specific gravity of the weight material, water = 1
Note, S_m for barite = 4.2

$$X' = 350(4.2) \left[\frac{(10 - 9.6)}{(8.33 \times 4.2) - 10} \right]$$

$$X' = \mathbf{23.5\,lbs\ barite/bbl\ mud}$$

Minimum volume of mud = 548 bbl in the drill pipe and annulus

$$\text{Barite required} = (23.5)(548)$$

$$\text{Barite required} = \mathbf{12{,}878\ lbs\ of\ barite}$$

Rate at which barite must be mixed:

$$\text{Rate} = (23.5)(3)$$

$$\text{Rate} = \mathbf{70.5\ lbs\ barite/min}$$

C. Compare the two procedures.
Table 4.5 and Fig. 4.18 compare the two methods.

D. The significance of 600 ft of 6 in. drill collars on the annulus pressure profile.

Table 4.5 Comparison of the Driller's method and wait-and-weight method

	Driller's method	**Wait-and-weight method**
Pressure at casing seat when well is first shut in	1300 psi	1300 psi
Pressure at casing seat when influx reaches that point	1480 psi	1418 psi
Fracture gradient at casing seat	1520 psi	1520 psi
Annulus pressure with gas to the surface	759 psi	706 psi
Height of the gas bubble at the surface	1165 ft	1264 ft
Total pit volume increase	50 bbl	54 bbl

Continued

Example 4.8—cont'd

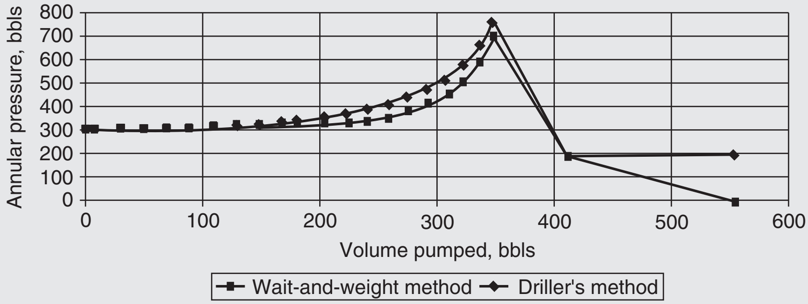


Fig. 4.18 Annular pressure profile, comparison.

The significance of adding 600 ft of drill collars to each example is that the initial shut-in annulus pressure will be higher because the bubble is longer. The new annular capacity due to the additional drill collars, C_{dcha}, is 0.0253 bbl/ft. Pursuant to Eq. (3.7), the new influx height is

$$h_b = \frac{Influx\ Volume}{C_{dcha}}$$

$$h_b = \frac{10}{0.0253}$$

$$h_b = \mathbf{395\ ft}$$

The annular pressure is given by Eq. (4.20):

$$P_a = P_b - \rho_m(D - h_x) - P_f$$

$$P_a = 5200 - 0.5(10,000 - 395) - 0.094(395)$$

$$P_a = \mathbf{360\ psi}$$

As Figs. 4.16–4.18 and Table 4.5 illustrate, the annulus pressure profile is exactly the same for both the Driller's method and the wait-and-weight method until the weighted mud reaches the bit. After the weighted mud passes the bit in the wait-and-weight method, the annulus pressures are lower than those experienced when the Driller's method is used.

In this example, the Driller's method may result in an underground blowout since the maximum pressure at the casing shoe, 1480 psi, is perilously close to the fracture gradient, 1520 psi. The well is more safely controlled using the wait-and-weight method since the maximum pressure at the casing seat, 1418 psi, is almost 100 psi below the fracture gradient.

Obviously, both displacement techniques would fail if a 200 psi "safety factor" was added to the circulating drill pipe pressure. This is another reason the wait-and-weight method is preferred.

In reality, the difference between the annulus pressure profiles may not be as pronounced due to influx migration during displacement. In the final analysis, the true annular pressure profile for the wait-and-weight method is probably somewhere between the profile for the Driller's method and the profile for the wait-and-weight method.

In part D, with 600 ft of drill collars in the hole, the annular area is smaller. Therefore, the length of the influx will be increased from 246 ft to 395 ft. As a result, the initial shut-in annulus pressure will be 360 psi is opposed to 300 psi. Using either the Driller's method or the wait-and-weight method, after 5 bbl is pumped, the influx will begin to shorten as it occupies the larger volume around the drill pipe. After 15 bbl of displacement is pumped, the influx is around the drill pipe, and the annulus profiles for both techniques are unaltered from that point forward (see Fig. 4.19).

The calculations of Example 4.8 are important so that rig personnel can be advised of the coming events. Being mentally prepared and forewarned may prevent a costly error. For example, if the Driller's method is used, rig personnel would expect that the maximum annulus pressure would be 759 psi, with gas to the surface; that the total pit level increase would be 50 bbls, which might cause the pits to run over; that gas would be at the surface in 2 h [(406 − 50)/3] or less, depending on influx migration; and that dry gas might be vented at the surface for a period of 20 min, at an equivalent rate of 12 million ft^3 of gas per day. Certainly, these events are enough to challenge the confidence of unsuspecting and uninitiated rig personnel and cause a major disaster. Be prepared and prepare all involved for the events to come.

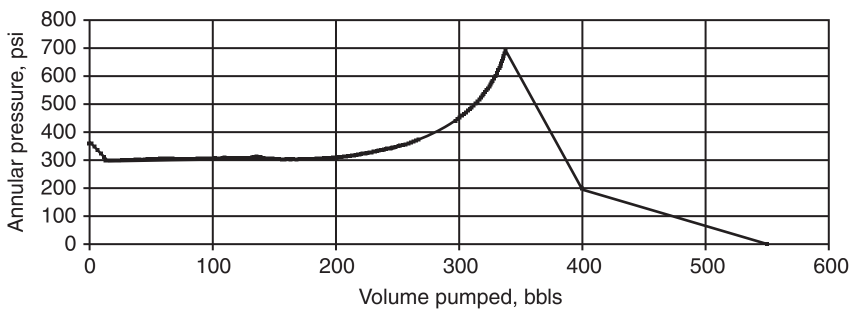


Fig. 4.19 Annular pressure profile, wait-and-weight method.

KICK TOLERANCE ENVELOPE

Now that the concepts used in determining the pressure in the annulus as the influx is circulated to the surface are understood, the determination of the kick tolerance envelope can be considered. It must be remembered that the kick tolerance envelope is that combination of underbalance and influx volume that can be safely circulated to the surface. As shown in Fig. 4.18, the casing pressures are always higher when the Driller's method is used to circulate an influx to the surface. Since the Driller's method represents a worst-case scenario, the kick tolerance envelope should be developed based on the concepts of the Driller's method.

The procedure involves determining conditions required to reach the critical pressure in the open hole. The critical pressure in the open hole is that pressure that will result in the rupture of the open hole and the loss of circulation. Therefore, constructing the kick tolerance envelope involves determining when in the circulating process the maximum pressure at the weakest point occurs. As a general statement, the maximum pressure at the weakest point occurs either when the well is first shut in or when the top of the influx first reaches the weak point in the open hole. Most usually, the weak point in the open hole is the last casing shoe. Therefore, absent information to the contrary, the kick tolerance will define the influx volume corresponding to the shut-in drill pipe pressure, which results in exceeding the fracture pressure at the last casing shoe.

One boundary would be the shut-in drill pipe pressure combined with the mud hydrostatic at the last casing shoe that would equal the fracture pressure at the last casing shoe. As given in Examples 2.1 and 4.8, the maximum permissible shut-in surface pressure for that example was 520 psi. Therefore, the maximum permissible influx volume for a shut-in drill pipe pressure of 520 psi would be 0 bbls. And, the underbalance for this condition would be

$$\text{Underbalanced, ppg} = \frac{P_{dp}}{0.052D} \tag{4.28}$$

$$\text{Underbalanced, ppg} = \frac{520}{0.052 \times 10000} = 1\,ppg$$

That value of a shut-in drill pipe pressure of 520 psi at 0 bbl influx represents one limit in the kick tolerance envelope.

The other limit is represented by the volume of influx that is required to exceed the fracture pressure at the weak zone when the pore pressure is equal to the mud hydrostatic pressure such as when the well has been swabbed in.

Eq. (4.20) can be rearranged to determine the influx height at the casing shoe, which results in equaling the fracture pressure at the shoe:

$$h_x = (P_a + \rho_m D - P_b)/\left(\rho_m - \rho_f\right) \tag{4.29}$$

The density of the influx at the casing shoe is given by Eq. (3.5):

$$\rho_f = \frac{S_g P_x}{53.3 z_x T_x}$$

$$\rho_f = \frac{0.6 \times 1518}{53.3 \times 0.811 \times 540} = 0.039 \frac{\text{psi}}{\text{ft}}$$

Therefore, substituting into Eq. (4.29), the height of the influx at the casing shoe, which results in the fracture pressure at the casing shoe, is

$$h_x = (520 + 0.052 \times 9.6 \times 10000 - 0.052 \times 9.6 \times 10000)/ \\ (0.052 \times 9.6 - 0.038)$$

$$h_x = 1130\,\text{ft}$$

Since the cross-sectional area at the shoe is the same as the cross-sectional area at the bottom of the hole, the height of the influx at the shoe is determined by the ideal gas law:

$$h_b = \frac{P_x h_x z_b T_b}{P_b z_x T_x}$$

$$h_b = \frac{1518 \times 1130 \times 1.007 \times 640}{4992 \times 0.811 \times 540} = 506\,\text{ft}$$

The critical influx volume then is the height multiplied by the capacity:

$$\text{Critical Influx Volume} = h_x C_{dpha}$$

$$\text{Critical Influx Volume} = 506 \times 0.0406 = 20.5\,bbls$$

The kick tolerance envelope can then be reasonably represented by a straight line drawn between these two points.

CONSTANT CASING PRESSURE, CONSTANT DRILL PIPE PRESSURE, AND MODIFICATION OF THE WAIT AND WEIGHT METHOD

After a well kick, the basic philosophy of control is the same, regardless of the procedure used. The total pressure against the kicking formation is maintained at a value sufficient to prevent further fluid entry and below the pressure that would fracture exposed formations. Simplicity is generally emphasized because decisions have to be made quickly when a well kicks and many people are involved in the control procedure.

With the inception of current well control procedures, there was a considerable emphasis on the Driller's method because the formation influx was immediately displaced. In recent years, it has become apparent that the Driller's method, while simple, may result in an underground blowout that could have been prevented. Thus, many operators have adopted the wait-and-weight method and accepted the necessity of increasing mud weight before displacement or during displacement of formation fluids. As illustrated in this chapter, the increase in mud weight requires an adjustment of drill pipe pressure during displacement of the weighted mud down the drill string. As a result, calculations are necessary to determine the pumping schedule required to maintain a constant bottom-hole pressure.

To minimize the calculations, a modification of the wait-and-weight method has become common. This procedure is known as the constant casing pressure, constant drill pipe pressure wait-and-weight method. It is very simple. The only modification is that the casing pressure is kept constant at the initial shut-in casing pressure until the weighted mud reaches the bit. At that point, the drill pipe pressure is recorded and kept constant until the influx has been displaced.

The significance of this approach is illustrated by analyzing Table 4.4 and Figs. 4.17 and 4.19. As illustrated, if there is no change in drill string geometry, as in the case of only one or two drill collars with heavyweight drill pipe, the casing pressure would be kept constant at 300 psi for the first 142 bbls of displacement. At that point, the casing pressure should be 352 psi. Obviously, the equivalent hydrostatic is less than the formation pressure and will continue to be less than the formation pressure throughout the displacement of the influx. Additional influx of formation fluid will be permitted, and the condition of the well will deteriorate into an underground blowout.

Pursuant to Fig. 4.19, if 600 ft of drill collars are present and the casing pressure is kept constant at 360 psi while the drill pipe is displaced with 142 bbls, the well will probably be safely controlled since the casing pressure at 142 bbls should be approximately 325 psi or only 35 psi less than the 360 psi being rather arbitrarily held. After the weighted mud reaches the bit, the drill pipe pressure would be held 35 psi higher than necessary to maintain the bottom-hole pressure constant at 5200 psi, while the influx is displaced. In this instance, that additional 35 psi would have no detrimental or harmful effects. However, each situation is unique and should be considered. For example, if larger collars are being used, the margin would be even greater.

The obvious conclusion is that the constant casing pressure, constant drill pipe pressure wait-and-weight method results in arbitrary pressure profiles, which can just as easily cause deterioration of the condition of the well or loss of the well. Therefore, use of this technique is not recommended without careful consideration of the consequences, which could result in the simplification being more complicated than the conventional wait-and-weight technique.

THE LOW CHOKE PRESSURE METHOD

Basically, the low choke pressure method dictates that some predetermined maximum permissible surface pressure will not be exceeded. In the event that pressure is reached, the casing pressure is maintained constant at that maximum permissible surface pressure by opening the choke, which obviously permits an additional influx of formation fluids. Once the choke size has to be reduced in order to maintain the maximum permissible annulus pressure, the drill pipe pressure is recorded, and that drill pipe pressure is kept constant for the duration of the displacement procedure.

The low choke pressure method is considered by many to be a viable alternative in classical pressure control procedures when the casing pressure exceeds the maximum permissible casing pressure. However, close scrutiny dictates that this method is applicable only when the formations have low productivity.

It is understood and accepted that an additional influx will occur. However, it is assumed that the second kick will be smaller than the first. If the assumption that the second kick will be smaller than the first is correct and the second kick is in fact smaller than the first, the well might ultimately be controlled. However, if the second kick is larger than the first, the well will be lost.

In Example 4.8, the maximum permissible annulus pressure is 520 psi, which is that surface pressure that would cause fracturing at the casing seat at 2000 ft. If the low choke pressure method was used in conjunction with the Driller's method in Example 4.8, the condition of the well would deteriorate to an underground blowout. Consider Table 4.3 and Fig. 4.17. Assuming that the Driller's method for displacement was being used, the drill pipe pressure would be held constant at 700 psi at a pump speed of 30 spm until 311 bbls had been pumped and the casing pressure reached 520 psi.

After 311 bbls of displacement, the choke would be opened in order to keep the casing pressure constant at 520 psi. As the choke was opened to maintain the casing pressure at 520 psi, the drill pipe pressure would drop below 700 psi, and additional formation fluids would enter the wellbore. The well would remain underbalanced until the influx, which is approximately 406 bbls, was circulated to the surface. At a pump rate of 3 bbls/min, the well would be underbalanced for approximately 32 min by as much as 186 psi!

Considering that during the original influx the underbalance was only 200 psi for much less than 32 min, the second influx is obviously excessive. Clearly, only a miracle will prevent an influx of formation fluids greater than the original influx of 10 bbls. That means that the well would ultimately be out of control since each successive bubble would be larger.

The low choke pressure method originated in West Texas, where formations are typically high pressure and low volume. In that environment, the well is circulated on a choke until the formation depletes. In any event, the productivity is seldom sustained at more than 1 mmscfpd. Occasionally, even in that environment, the productivity is high, resulting in a serious well control problem. Therefore, in general, the low choke pressure method is an acceptable procedure only in areas of known low productivity and even in that environment can result in very serious well control problems and ultimate loss of the well. When inadvertently used in areas of high productivity, disasters of major proportions can result. The low choke pressure method is not generally recommended.

REVERSE THE BUBBLE OUT THROUGH THE DRILL PIPE

It is becoming increasingly common to reverse the influx out through the drill pipe. When the bubble is reversed out, the pressure profiles for the drill pipe and annulus are reversed, resulting in a reduction in annulus pressure when the wait-and-weight method is used and a constant casing pressure when the Driller's method is used. The potential hazards of bridging the annulus or plugging the bit or drill pipe are the primary objections to utilizing the reverse circulation technique; however, industry experience utilizing this technique has been successful, and the industry has not experienced either drill string plugging, bit plugging, or bridging in the annulus.

Planning is essential if reverse circulation is anticipated since it must be convenient to tie the drill pipe into the choke-manifold system. In addition, if time permits, it is recommended that the jets be blown out of the bit. A float in the drill string is not an insurmountable obstacle in that it can be blown out of the drill string along with the jets in the bit. As an alternative, a metal bar can be pumped through the float to hold it open during the reverse circulating operation. To date, reverse circulating the influx to the surface through the drill pipe has not become a common technique; however, the limited experience of the industry to date has been good, and the technical literature is promising. Having directional tools in the drill string would prohibit reversing the bubble out. All directional tools are run with a float, and there would be no access to the float.

Operationally, reverse circulating is difficult due to the problems involved in commencing. As illustrated in Fig. 4.20, the influx is in the annulus at first, and within a few strokes, it moves into the drill pipe. Therefore, the pressures on the drill pipe and annulus are changing rapidly during the first few strokes. The pressure on the drill pipe will increase to a value greater than the original shut-in annulus pressure, while the pressure on the annulus will decline to the original shut-in drill pipe pressure. The U-tube model does not apply to the first few strokes; hence, there is no definitive and easy procedure for circulating the influx into the drill pipe.

Another consideration is that in classical pressure control, most of the frictional pressure losses are in the drill pipe. Therefore, the circulating pressure at the casing shoe is not affected by the frictional pressure losses.

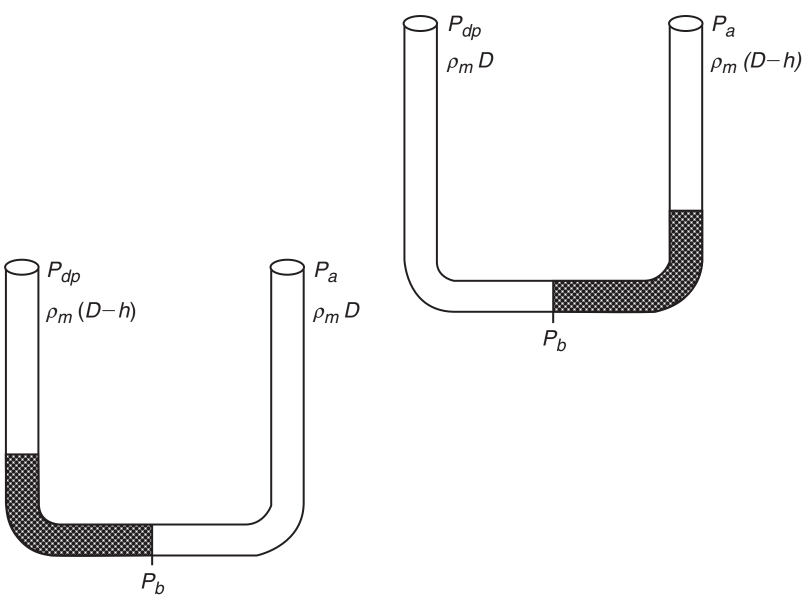


Fig. 4.20 Effect of reverse circulation on U-tube model.

However, with reverse circulation, any frictional pressure losses in the system are applied to the casing seat, which is the weak point in the circulating system. It is imperative that the procedure be designed with emphasis on the fracture pressure at the casing shoe. Consider Example 4.9:

Example 4.9

Given:

Wellbore schematic = Fig. 4.7
Well depth, $D = 10{,}000$ ft
Hole size, $D_h = 7\frac{7}{8}$ in
Drill pipe size, $D_p = 4\frac{1}{2}$ in
$8\frac{5}{8}$ in. surface casing = 2000 ft
Casing internal diameter, $D_{ci} = 8.017$ in.
Fracture gradient, $F_g = 0.76$ psi/ft
Fracture pressure = 1520 psi
Mud weight, $\rho = 9.6$ ppg
Mud gradient, $\rho_m = 0.50$ psi/ft
A kick is taken with the drill string on bottom and
Shut-in drill pipe pressure, $P_{dp} = 200$ psi
Shut-in annulus pressure, $P_a = 300$ psi
Pit level increase = 10 bbls
Kill-mud weight, $\rho_1 = 10$ ppg
Kill-mud gradient, $\rho_{m1} = 0.52$ psi/ft
Normal circulation = 6 bpm at 60 spm
Kill rate = 3 bpm at 30 spm
Circulating pressure at kill rate, $P_{ks} = 500$ psi
Pump capacity, $C_p = 0.1$ bbl/stk
Capacity of the
  Drill pipe (inside), $C_{dpi} = 0.0142$ bbl/ft
  Drill pipe casing annulus, $C_{dpca} = 0.0428$ bbl/ft
  Drill pipe hole annulus, $C_{dpha} = 0.0406$ bbl/ft
Initial displacement pressure, $P_c = 700$ psi at 30 spm
Shut-in bottom-hole pressure, $P_b = 5200$ psi
Maximum permissible surface pressure = 520 psi
Ambient temperature = 60°F
Geothermal gradient = 1.0°/100 ft
$\rho_f h = P_f = 23$ psi
$h_b = 246$ ft

Required:

Prepare a schedule to reverse circulate the influx to the surface.

Example 4.9—cont'd

Solution:

1. The first problem is to get the gain into the drill pipe.
   The maximum annulus pressure is given as 520 psi.
   Therefore, the circulating annulus pressure must not exceed 520 psi.
2. Determine the volume rate of flow, Q, such that the frictional pressure is less than the difference between the maximum permissible annulus pressure and the shut-in annulus pressure.

The maximum permissible annular frictional pressure is

$$520 - 300\,\text{psi} = 220\,\text{psi}$$

From the relationship given in Eq. (4.14)

$$P \propto Q^{1.8}$$

If at $Q = 30$ spm and $P = 500$ psi, Q may be determined for $P = 220$ psi as follows:

$$\left(\frac{Q}{30}\right)^{1.8} = \left(\frac{220}{500}\right)$$

$$Q = \mathbf{19\ spm}$$

Therefore, the bubble must be reversed at rates less than 19 spm (1.9 bpm) to prevent fracturing the shoe.

Choose 1 bbl/min = 10 spm.

3. Conventionally, pump the influx up the annulus 100 stk (an arbitrary amount) using the Driller's method, keeping the drill pipe pressure constant.
4. Shut in the well.
5. Begin reverse circulation by keeping the drill pipe pressure constant at 200 psi while bringing the pump to speed approximately equal to 10 spm, with the annulus pressure not to exceed 500 psi. Total volume pumped in this step must not exceed that pumped in step 3 (100 stk in this example).
6. Once the rate is established, read the annulus pressure and keep that pressure constant until the influx is completely displaced.
7. Once the influx is out, shut in and read that the drill pipe pressure equals the annulus pressure equals 200 psi.
8. Circulating conventionally (the long way), circulate the kill-weight mud to the bit keeping the annulus pressure equal to 200 psi.

The choke should not change during this step. The only change in pit level should be that caused by adding barite. If not, shut in.

9. With kill mud at the bit, read the drill pipe pressure and circulate kill mud to the surface, keeping the drill pipe pressure constant.
10. Circulate and weight up to provide desired trip margin.

Once the influx is in the drill pipe, the procedure is the same as that for the Driller's method. Calculations such as presented in Example 4.8 can be used. With the influx inside the drill pipe, the drill pipe pressure would be 487 psi. The maximum pressure on the drill pipe would be 1308 psi and would occur when the influx reached the surface. The influx would be 2347 ft long at the surface, and the total pit gain would be 33 bbls. The time required to bring the gas to the surface would be 109 min, and displacement of the influx would require 33 min. The distinct advantage is that the casing shoe would be protected from excessive pressure and an underground blowout would be avoided.

Once the influx is definitely in the drill pipe, the annulus pressure could be reduced by the difference between the original shut-in drill pipe pressure and the original shut-in annulus pressure, which is 100 psi in this example. The pressure on the annulus necessary to keep the bottom-hole pressure constant at the original shut-in bottom-hole pressure is the equivalent of the original shut-in drill pipe pressure plus the frictional pressure loss in the circulating system.

THE OVERKILL WAIT-AND-WEIGHT METHOD

The overkill wait-and-weight method is the wait-and-weight method using a mud density greater than the calculated density for the kill-weight mud. Analysis of Example 4.8 indicates that the use of kill-weight mud to displace the gas bubble reduced the pressures in the annulus. It follows that, if increasing the mud weight from 9.6 lb/gal to 10 lb/gal reduced the pressure at the casing seat by 62 psi as shown in Table 4.5, then additional increases in mud weight would further reduce the pressure at the casing seat. The maximum practical density would be that that would result in a vacuum on the drill pipe. The effect on the pressure at the casing seat of utilizing such a technique is calculable.

Consider the utilization under the conditions described in Example 4.10:

Example 4.10

Given:

Example 4.6

Required:

1. The effect on the pressure at the casing seat when the density of the kill-weight mud is increased to 11 ppg.

Example 4.10—cont'd

2. The appropriate pumping schedule for displacing the influx with 11 ppg mud.

Solution:

1. For the wait-and-weight method, the pressure at the casing seat at 2000 ft when the top of the influx reaches that point is given by Eq. (4.25):

$$P_{xww} = \frac{B_1}{2} + \left[\frac{B_1^2}{4} + \frac{P_b \rho_{m1} z_x T_x h_b A_b}{z_b T_b A_x}\right]^{\frac{1}{2}}$$

$$B_1 = P_b - \rho_{m1}(D - X) - P_f \frac{A_b}{A_x} + l_{vds}(\rho_{m1} - \rho_m)$$

$$B_1 = 5200 - 0.572(10{,}000 - 2000)$$

$$-23\left[\frac{32.80}{32.80}\right] + \left(\frac{142}{0.0406}\right)(0.572 - 0.50)$$

$$B_1 = \mathbf{852}$$

$$P_{2000ww} = \frac{852}{2} + \left[\frac{852^2}{4}\right.$$

$$\left. + \frac{5200(0.572)(0.828)(540)(246)(32.80)}{(620)(1.007)(32.80)}\right]^{\frac{1}{2}}$$

$$p_{2000ww} = \mathbf{1267\ psi}$$

2. The appropriate pumping schedule may be determined using Eqs. (2.11), (2.14) and is illustrated in Fig. 4.21:

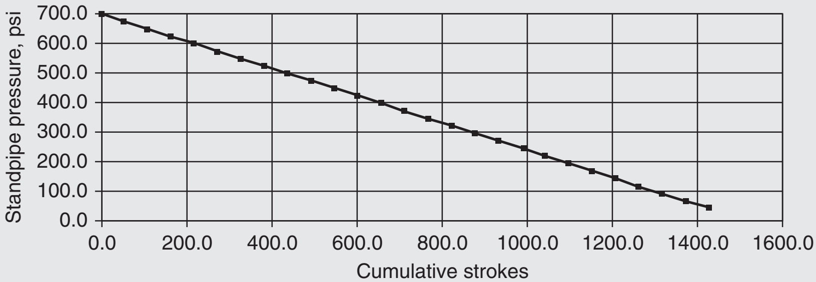


Fig. 4.21 Standpipe pressure schedule using 11.0 ppg mud.

Continued

Example 4.10—cont'd

$$P_{cn} = P_{dp} - 0.52(\rho_1 - \rho)D + \left(\frac{\rho_1}{\rho}\right)P_{ks}$$

$$P_{cn} = 200 - 0.052(11.0 - 9.6)10,000 + \left(\frac{11.0}{9.6}\right)500$$

$$P_{cn} = \mathbf{45\ psi}$$

From Eq. (2.14)

$$\frac{STKS}{25\text{ psi}} = \frac{25(STB)}{P_c - P_{cn}}$$

$$\frac{STKS}{25} = \frac{25(1420)}{700 - 45}$$

$$\frac{STKS}{25} = 55$$

The drill pipe pressure schedule is calculated in Table 4.6.

Obviously, the Driller's method and the wait-and-weight method result in the same annulus profile, while the drill pipe is being displaced since it contains unweighted mud of density ρ. In this instance, the drill pipe capacity is 142 bbls, which means that both techniques have the same effect on annulus pressure for that period regardless of the density of the kill-weight mud being used in the wait-and-weight method.

As illustrated in Table 4.4, the annulus pressure at the surface after 142 bbls is approximately 325 psi. Therefore, the pressure at the shoe at 2000 ft after 142 bbls is approximately 1325 psi. Pursuant to Example 4.10, the pressure at the casing seat when the influx reaches the casing seat is 1267 psi. Therefore, the maximum pressure at the casing seat occurred when the weighted mud reached the bit. In this example, with the 11 ppg kill-weight mud, the maximum pressure at the casing seat was almost 200 psi less than the fracture pressure of 1520 psi. The annulus pressure profile is illustrated as Fig. 4.22.

In order to maintain the bottom-hole pressure constant at 5200 psi, the drill pipe pressure must be reduced systematically to 45 psi and held constant throughout the remainder of the displacement procedure. Failure to consider properly reduction in drill pipe pressure resulting from the increased density is the most common cause of failure of the overkill wait-and-weight method. Properly utilized as illustrated in Example 4.10, the overkill

Table 4.6 Standpipe pressure schedule

Cumulative strokes	Standpipe pressure
0	700
55	675
110	649
165	624
220	599
275	573
330	548
385	523
440	497
495	472
550	446
605	421
660	396
715	370
770	345
825	320
880	294
935	269
990	244
1045	218
1100	193
1155	168
1210	142
1265	117
1320	91
1375	66
1430	45

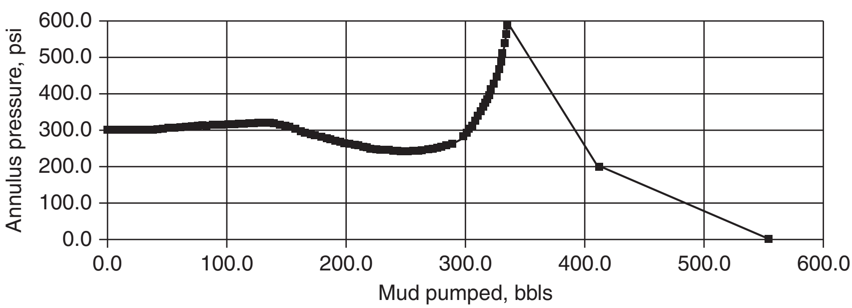


Fig. 4.22 Annulus pressure profile, 11.0 ppg kill mud.

wait-and-weight method can be a good alternative well control displacement procedure when casing shoe pressures approach fracture pressures and an underground blowout threatens.

SLIM-HOLE DRILLING—CONTINUOUS CORING CONSIDERATIONS

Continuous coring utilizing conventional hard-rock mining equipment to conduct slim-hole drilling operations offers unique considerations in pressure control. A typical slim-hole-wellbore schematic is illustrated in Fig. 4.23. As previously discussed, the classical pressure control displacement procedures assume that the only significant frictional pressure losses are in the drill string and that the frictional pressure losses in the annulus are negligible.

As can be seen from an analysis of Fig. 4.23, in slim-hole drilling, the conditions are reversed. That is, the frictional pressure losses in the drill string are negligible, and the frictional pressure losses in the annulus are considerable. In addition, in slim-hole drilling, the volume of the influx is much more critical because the annulus area is small. Under normal conditions, a 1 bbl influx would not result in a significant surface annulus pressure. However, in slim-hole drilling, a 1 bbl influx may result in excessive annular pressures.

The best and most extensive work in this area has been done by Amoco Production Company [1]. Sensitive flow meters have been developed, which are capable of detecting extremely small influxes. Provided that the casing seats are properly selected and the influx volume is limited, classical pressure control procedures can be used. However, consideration must be given to frictional pressure losses in the annulus.

The first step is to measure the surface pressure as a function of the circulation rate as discussed in Chapter two. Modeling must then be performed to match the measured values for frictional pressure losses in order that the frictional pressure losses in the annulus may be accurately determined. Fig. 4.24 illustrates a typical pressure determination for the wellbore schematic in Fig. 4.23. If, for example, the influx was to be circulated out at 40 gal/min, the drill pipe pressure during displacement would have to be reduced by the frictional pressure loss in the annulus, which is approximately 1000 psi in Fig. 4.24. The circulating pressure at the kill speed is given by Eq. (4.30):

$$P_{kssl} = P_c + P_{dp} - P_{fa} \tag{4.30}$$

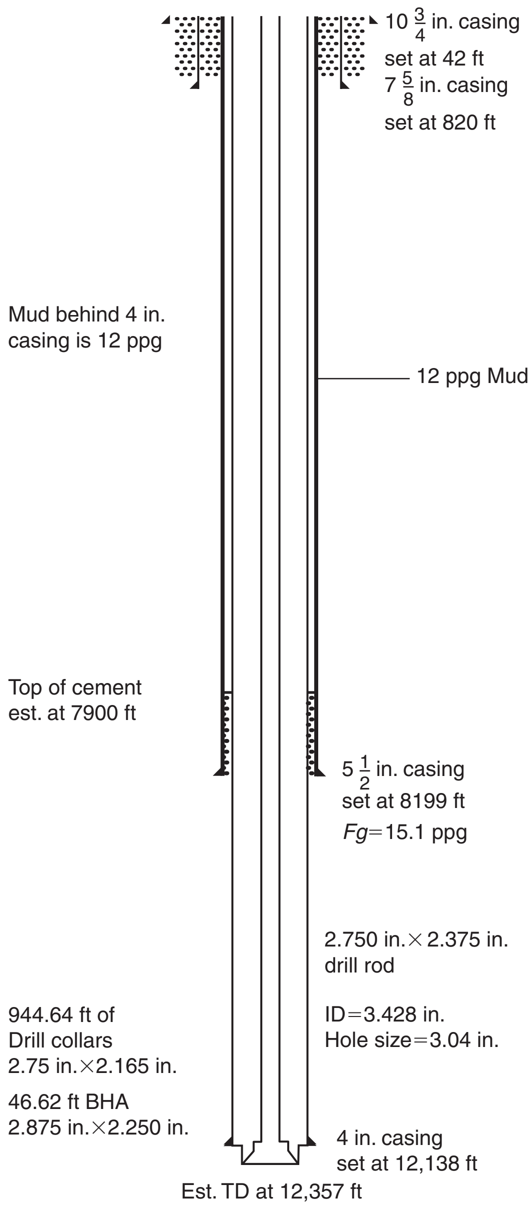


Fig. 4.23 Typical slim-hole wellbore.

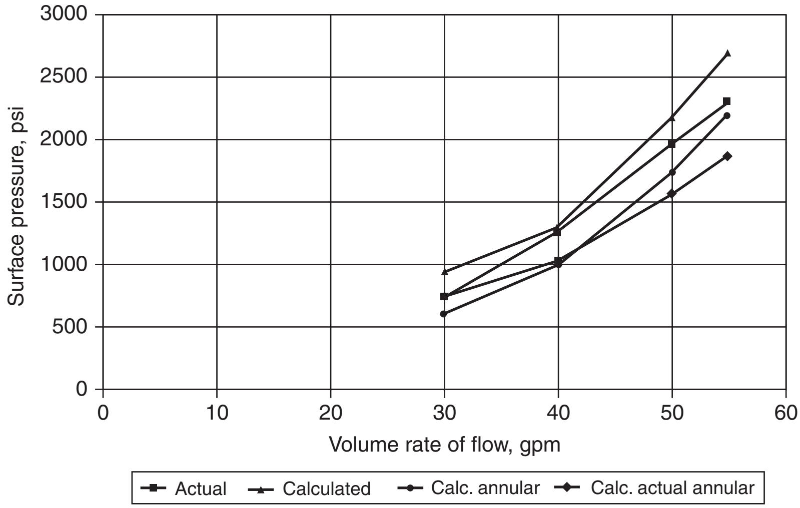


Fig. 4.24 Pump test.

where

P_{kssl} = circulating pressure at kill speed, psi
P_c = initial circulating pressure loss, psi
P_{dp} = shut-in drill pipe pressure, psi
P_{fa} = frictional pressure loss in annulus, psi

Since the influx will be displaced from the annulus before the weighted mud can reach the bit, the only classical displacement procedure applicable to most slim-hole drilling operations is the Driller's method. Therefore, pursuant to Fig. 4.24 and Eq. (4.30), if the shut-in drill pipe pressure was 1500 psi, the shut-in casing pressure was 1700 psi, and the kill rate was 40 gpm; then, the displacement pressure at the kill speed would be given by Eq. (4.30) as follows:

$$P_{kssl} = P_c + P_{dp} - P_{fa}$$
$$P_{kssl} = 1300 + 1500 - 1000$$
$$P_{kssl} = \mathbf{1800\ psi}$$

Bringing the pump to speed for the displacement of the influx is not as straightforward as in conventional drilling operations. That is, keeping the casing pressure constant while bringing the pump to speed results in excessive pressure at the casing shoe. Therefore, the pump must be brought to speed, while the casing pressure is being permitted to decline by the amount of the frictional pressure in the annulus. For example, if the shut-in casing pressure is 1700 psi, the pump would be brought to a speed of 40 gpm, permitting the casing pressure to decline by 1000 to 700 psi. At the same time, the drill pipe pressure would be increasing to 1800 psi. Once the appropriate drill pipe pressure is obtained, it would be held constant, while the influx is circulated to the surface.

Since the annular frictional pressure losses are high and can result in an equivalent circulating density that is several pounds per gallon greater than the mud density, it is anticipated that influxes will occur when circulation is stopped for a connection. In that event, the influx can be circulated to the surface dynamically using the same circulating rate and drill pipe pressure as was used during the drilling operation.

Slim-hole drilling offers the advantage of continuous coring. However, continuous coring requires the wire line retrieval of a core barrel after every 20–40 ft. The operation is particularly vulnerable to a kick during the retrieval of the core due to the potential swabbing action of the core barrel. The standard practice is to pump the drill rod down slowly during all core retrieval operations to insure that full hydrostatic is maintained.

The equipment required in slim-hole drilling operations must be as substantial as in normal drilling operations. The choking effect of the annulus on a well flowing out of control is not as significant as might be expected. Therefore, the full complement of well control equipment is needed. Since it is more likely that the well will flow to the surface, particular attention must be focused on the choke manifold and flare lines.

The systems outlined in Chapter one are applicable to slim-hole drilling with two exceptions. Since a top drive is used and the drill rods have a constant outside diameter, an annular preventer is not required. In addition, since the drill rods do not have conventional upset tool joints, slip rams should be included in the blowout preventer stack to prevent the drill rods from being blown out of the hole.

STRIPPING WITH INFLUX MIGRATION

The proper procedure for stripping was discussed in Chapter three. However, the procedure presented in Chapter three does not consider influx migration. To perform a stripping operation accurately with influx migration, the classical procedure in Chapter three must be combined with the volumetric procedures outlined in this chapter. The combined procedure is not difficult. The stripping operation is carried out normally as presented in Chapter three.

As the influx migrates, the surface pressure will slowly increase. When the surface pressure becomes unacceptable or reaches a predetermined maximum, the stripping operation is discontinued, and the influx is expanded pursuant to the volumetric procedures presented in this chapter. Once the influx is expanded, the stripping operation is resumed.

Shell Oil has developed and reported a rather simple and technically correct procedure for stripping into the hole with influx migration. Equipment is required, which is not normally available on the rig; therefore, preplanning is a necessity. The required equipment consists of a calibrated trip tank and a calibrated stripping tank and is illustrated in Fig. 4.25.

Basically, the surface pressure is held constant, while a stand is stripped into the hole. The mud is displaced into the calibrated trip tank. The theoretical displacement of the stand is then drained into the calibrated stripping tank. Any increase in the volume of the mud in the trip tank is recorded.

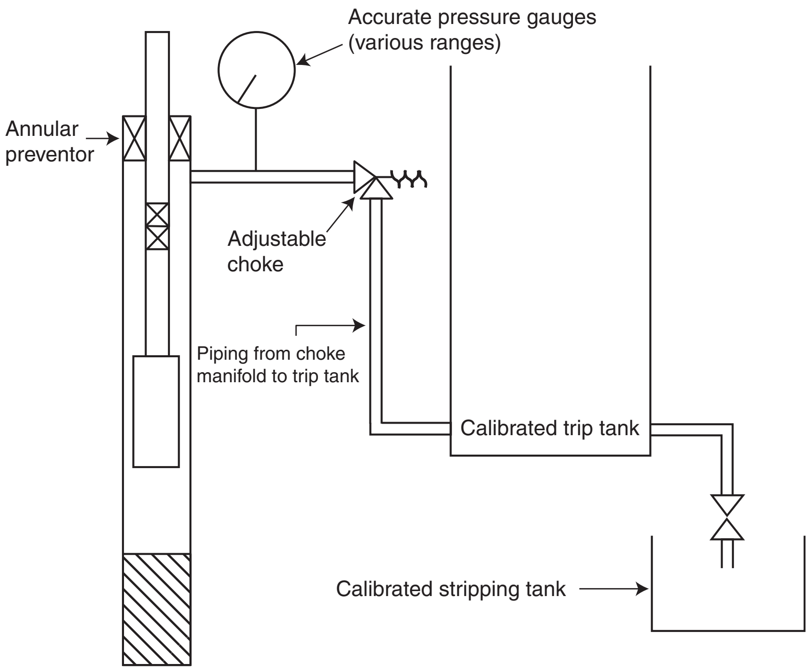


Fig. 4.25 Stripping equipment for shell method.

The hydrostatic equivalent of the increase in volume is then added to the choke pressure. As a safety factor, the minimum annular areas are used in determining the equivalent hydrostatic of mud displaced from the hole. The procedure is as follows:

Step 1

After closing in the well, determine the influx volume and record the surface pressure.

Step 2

Determine the volume of drilling mud in the open-hole, drill-collar annulus equivalent to 1 psi of mud hydrostatic.

Step 3

Adopt a convenient working pressure increment, P_{wpi}. The working pressure increment is arbitrary, but the fracture gradient should be considered.

Step 4

Determine the volume increase in the trip tank represented by the equivalent hydrostatic of the working pressure increment.

Step 5

Determine the additional back pressure, P_{hydl}, required when the influx is in the minimum annular area, which is usually the drill-collar, open-hole annulus.

Step 6

While stripping the first stand into the hole, permit the surface pressure to increase to P_{choke} where

$$P_{choke} = P_a + P_{hydl} + P_{wpi} \tag{4.31}$$

Step 7

Strip pipe into the hole maintaining P_{choke} constant.

Step 8

After each stand is stripped into the hole, drain the theoretical displacement into the calibrated tripping tank. Record any change in the volume of mud in the trip tank.

Step 9

When the increase in volume of mud in the trip tank equals the volume determined in Step 4, increase P_{choke} by P_{wpi} and continue.

Step 10

Repeat Steps 7–9 until the pipe is returned to bottom.

Consider Example 4.11:

Example 4.11

Given:

Wellbore schematic = Fig. 3.2
Well depth, $D = 10{,}000$ ft
Number of stands pulled = 10 stands
Length per stand, $L_{std} = 93$ ft/std
Stands to be stripped = 10 stands
Drill pipe to be stripped $= 4\frac{1}{2}$ in
Drill string displacement, $DSP_{ds} = 2$ bbl/std
Mud density, $\rho = 9.6$ ppg
Influx = 10 bbl of gas
Capacity of drill pipe annulus, $C_{dpha} = 0.0406$ bbl/ft
Hole diameter, $D_h = 7\frac{7}{8}$ in
Hole capacity, $C_h = 0.0603$ bbl/ft
Bottom-hole pressure, $P_b = 5000$ psi
Bottom-hole temperature, $T_b = 620°R$
Gas specific gravity, $S_g = 0.6$
Shut-in casing pressure, $P_a = 75$ psi
$P_{wpi} = 50$ psi
Trip tank volume = 2 in./bbl

Required:

Describe the procedure for stripping the 10 stands back to bottom using the shell method.

Solution:

Equivalent hydrostatic of 1 bbl of mud in the drill pipe annulus is given by Eq. (4.10):

$$P_{hem} = \frac{0.052\rho}{C_{dpha}}$$
$$P_{hem} = \frac{0.052(9.6)}{0.0406}$$
$$P_{hem} = \mathbf{12.3\ psi/bbl}$$

Therefore, for a 10 bbl influx,

$$P_{hydl} = 10(12.3)$$
$$P_{hydl} = \mathbf{123\ psi}$$

From Eq. (4.31),

$$P_{choke} = 75 + 123 + 50$$
$$P_{choke} = \mathbf{248\ psi}$$

Example 4.11—cont'd

Therefore, strip the first stand into the hole and permit the choke pressure to increase to 250 psi. Bleed mud proportional to the amount of drill pipe stripped after reaching 250 psi.

Continue to strip pipe into the hole, keeping the surface pressure constant at 250 psi.

After each stand, bleed 2 bbls of mud into the stripping tank and record the volume in the trip tank.

When the volume in the trip tank has increased by 8 in., increase the surface pressure to 300 psi and continue. Eight inches represents the volume of the equivalent hydrostatic of the 50 psi working pressure increment (50 psi divided by 12.3 psi/bbl multiplied by 2 in./bbl).

OIL-BASE MUD IN PRESSURE AND WELL CONTROL OPERATIONS

There is widespread use of oil or synthetic-based drilling fluids in drilling operations. However, from the beginning, well control problems with unusual circumstances associated will oil-based muds have been observed. Typically, field personnel reports of well control problems with oil muds are as follows:

Nothing adds up with an oil mud.

It happened all at once! We had a 200-barrel gain in 2 minutes! There was nothing we could do! It was on us before we could do anything!

We saw nothing—no pit gain … nothing—until the well was flowing wildly out of control! We shut it in as fast as we could, but the pressures were too high! We lost the well!

We started out of the hole and it just didn't act right. It was filling OK, but it just didn't seem right. We shut it in and didn't see anything—no pressure, nothing! We still weren't satisfied; so we circulated all night. Still we saw nothing—no pit gain—no gas-cut mud—nothing. We circulated several hole volumes and just watched it. It looked OK! We pulled 10 stands, and the well began to flow. It flowed 100 bbls before we could get it shut in! I saw the pressure on the manifold go over 6000 psi before the line blew. It was all over then! We lost the rig!

We had just finished a trip from below 16,000 feet. Everything went great! The hole filled like it was supposed to, and the pipe went right to bottom. We had gone back to drilling. We had already drilled our sand. We didn't drill anything new but shale and had not circulated bottoms up. Everything was going good. Then, I looked around and there was mud all over the location! I looked back toward the floor and there was mud going over the bushings! Before I could close the Hydril, the mud was going to the board! I got it shut in okay, but somehow the oil mud caught on fire in the derrick and on the rotary hose! The fire burned the rotary hose off and the well blew out up the drill pipe! It took about 30 min for the derrick to go! It was a terrible mess! We were paying attention! It just got us before we could do anything.

Fire

The most obvious problem is that oil-based muds will burn. The flash point of a liquid hydrocarbon is the temperature to which it must be heated to emit sufficient flammable vapor to flash when brought into contact with a flame. The fire point of a hydrocarbon liquid is the higher temperature at which the oil vapors will continue to burn when ignited. In general, the open flash point is 50–70°F less than the fire point.

Most oil-based muds are made with no. 2 diesel oil. The flash point for diesel is generally accepted to be about 140°F. On that basis, the fire point would be about 200°F. Mixing the oil-based mud with hydrocarbons from the reservoir will only increase the tendency to burn. The exposure of gas with the proper concentrations of air to any open flame or a source capable of raising the temperature of the air-gas mixture to about 1200°F will result in a fire.

Solubility of Natural Gas in Oil-Base Mud

It is well known in reservoir engineering that such hydrocarbons as methane, hydrogen sulfide, and carbon dioxide are extremely soluble in oil. With the popularity of oil muds used in routine drilling operations in recent years, considerable research has been performed relative to the solubility of hydrocarbons in oil muds [2,3]. As illustrated in Fig. 4.26, the solubility of methane increases virtually linearly to approximately 6000 psi at 250°F. The methane solubility becomes asymptotic at 7000 psi, which basically means that the solubility of methane is infinite at pressures of 7000 psi or greater and temperatures of 250°F or greater. The pressure at which the solubility becomes infinite is defined as the miscibility pressure.

Note in Fig. 4.26 that the solubility of carbon dioxide and hydrogen sulfide is higher than that of methane. The miscibility pressure of methane decreases with temperature, as illustrated in Fig. 4.27, while the miscibility pressure of carbon dioxide and hydrogen sulfide increases with temperature.

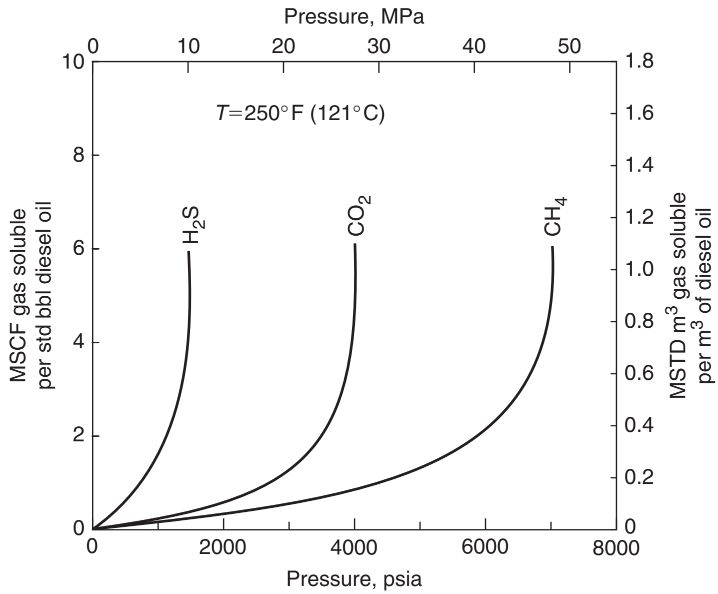


Fig. 4.26 Gas solubility in diesel oil.

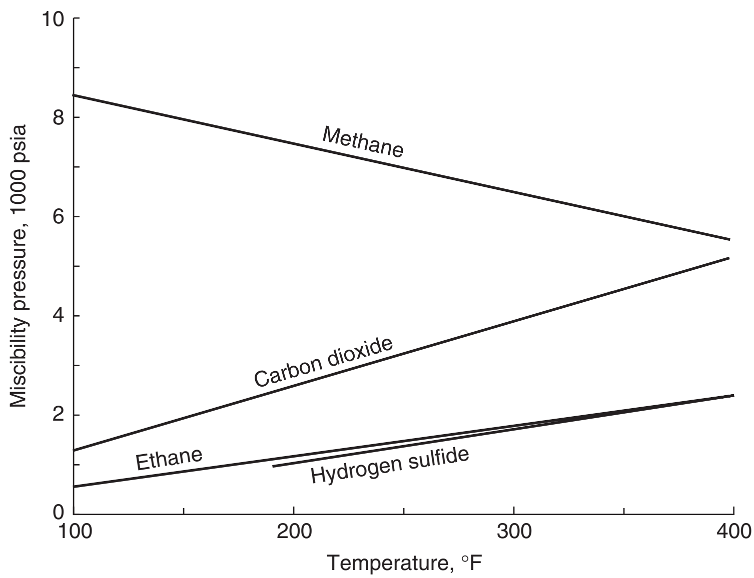


Fig. 4.27 Miscibility pressure versus temperature.

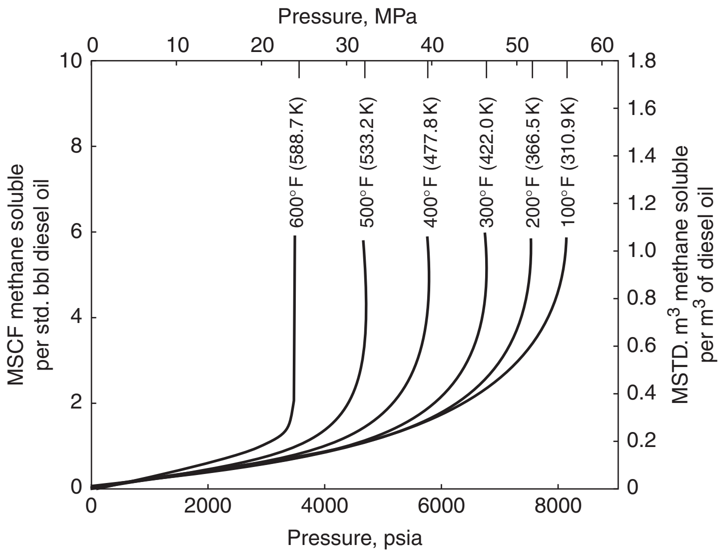


Fig. 4.28 Methane solubility as a function of temperature.

As further illustrated in Fig. 4.28, the miscibility pressure of methane decreases from about 8000 psi at 100°F to approximately 3000 psi at 600°F.

The significance of this research to field operations is that in deep, high-pressure gas wells, an influx of reservoir hydrocarbons can, in part, dissolve in an oil-based mud. Another variable that will be discussed is the manner in which the influx occurs. However, in the most simple illustration, when a kick is taken while drilling with an oil-based mud and the influx is primarily methane, the influx will dissolve into the mud system and effectively mask the presence of the influx. That is not to say that 1 bbl of oil-based mud and 1 bbl of reservoir hydrocarbon result in 1 bbl of a combination of the two.

However, it is certain that under the aforementioned conditions 1 bbl of oil-based mud and 1 bbl of reservoir hydrocarbon in the gaseous phase will yield something less than 2 bbls. Therefore, the danger signals that the man in the field normally observes are more subtle. The rate of gain in the pit level when using an oil-mud system will be much less than the rate of gain when using a water-based system.

The exact behavior of a particular system is unpredictable. The phase behavior of hydrocarbons is very complex and individual to the precise composition of the system. Furthermore, the phase behavior changes as the phases change. That is, when the gas does begin to break out of solution, the phase behavior of the remainder of the liquid phase shifts and changes. Therefore, only generalized observations can be made.

Again, assuming the most simple example of taking a kick while drilling on bottom, the influx is partially dissolved into the oil phase of the mud system. A typical phase diagram is illustrated in Fig. 4.29. Under such conditions, the drilling fluid is represented by point "A." Point A represents a hydrocarbon system above the bubble point with all gas in solution. As the influx is circulated up the hole, the gas will remain in solution until the bubble point is reached.

The hydrocarbon system then enters the two-phase region. As the hydrocarbon continues up the hole, more and more gas breaks out. As the gas breaks out, the liquid hydrostatic is replaced by the gas hydrostatic, and the effective hydrostatic on bottom will decrease, permitting additional influx at an exponentially increasing rate. This can account for the field observation of high flow rates and rapidly developing events.

The pressure behavior of kicks in oil-based muds can be confusing. Using the previous illustration, if a well is shut in after observing a 10 bbl gain at the surface, it is probable that a much larger gain has been taken. However, due to the compressibility of the system, the surface pressure

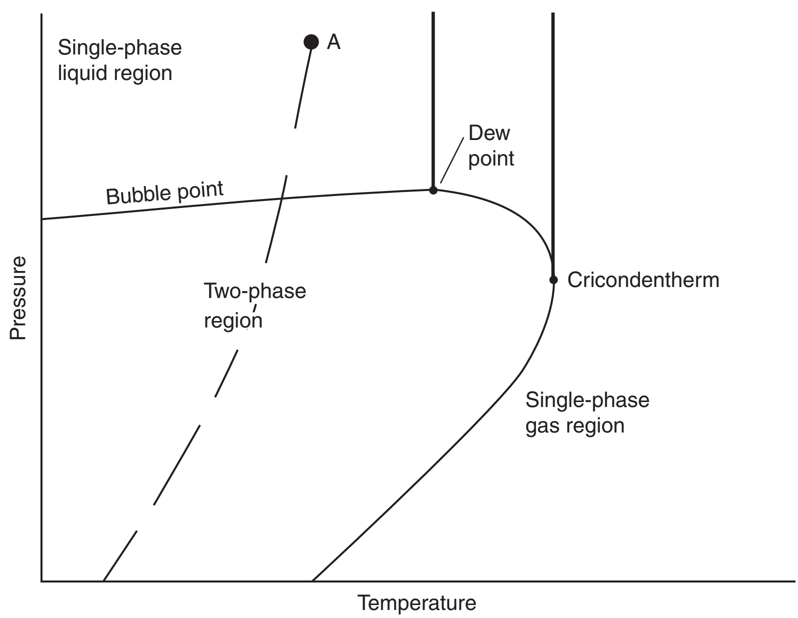


Fig. 4.29 Typical hydrocarbon phase diagram.

on the annulus may be less than that observed with a 10 bbl surface gain in a water-based mud.

As the gas is circulated to the surface and begins to break out of solution, the kick will begin to behave more like a kick in a water-based mud, and the annular pressure will respond accordingly. As illustrated in Fig. 4.28, the solubility of methane in diesel oil is very low at low pressure and almost any reasonable temperature. Therefore, when the gas reaches the surface, the annular pressure will be much higher than expected and almost that anticipated with the same kick in a water-based mud. This scenario is schematically illustrated in Fig. 4.30.

Research has shown that the solubility of the influx into the mud system is a more significant problem when the influx is widely distributed. A kick taken while on bottom drilling is an example. An influx that is in a bubble and not mixed behaves more like an influx in a water-based system. A kick that is taken while tripping or while making a connection with the pump off is an illustration.

To further complicate matters, the density of an oil-based mud is affected by temperature and pressure. As a result, an oil-based mud may have a density of 17 ppg at the surface but a different density under bottom-hole conditions. These concepts are very difficult to quantify, visualize, and verbalize. Most mud companies have a computer program for adjusting the density based on pressure and temperature. The experience of the industry along with a technical analysis dictates that much more caution must be exercised when drilling with an oil-based mud. For example, if a well is observed for flow for 15 min using a water-based mud, it should be observed longer when an oil-based mud is being used. Unfortunately, precise field calculations cannot be made due to the complexity of the phase behavior of the

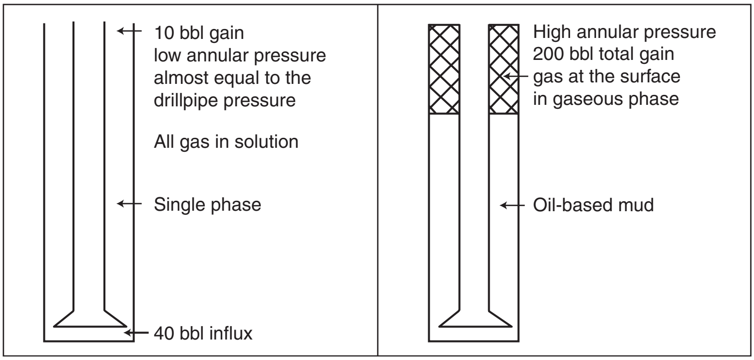


Fig. 4.30 Complexities of oil-based muds.

hydrocarbons involved. Well control problems are significantly complicated when oil-based muds are used and the consequences are more severe.

FLOATING DRILLING AND SUBSEA OPERATION CONSIDERATIONS

Subsea Stack

Recently, in some explanatory operations, operators have utilized high-pressure risers and surface blowout preventers. However, in most floating drilling operations, the blowout preventers are located on the sea floor, necessitating redundancy on much of the equipment. Fig. 4.31 demonstrates the

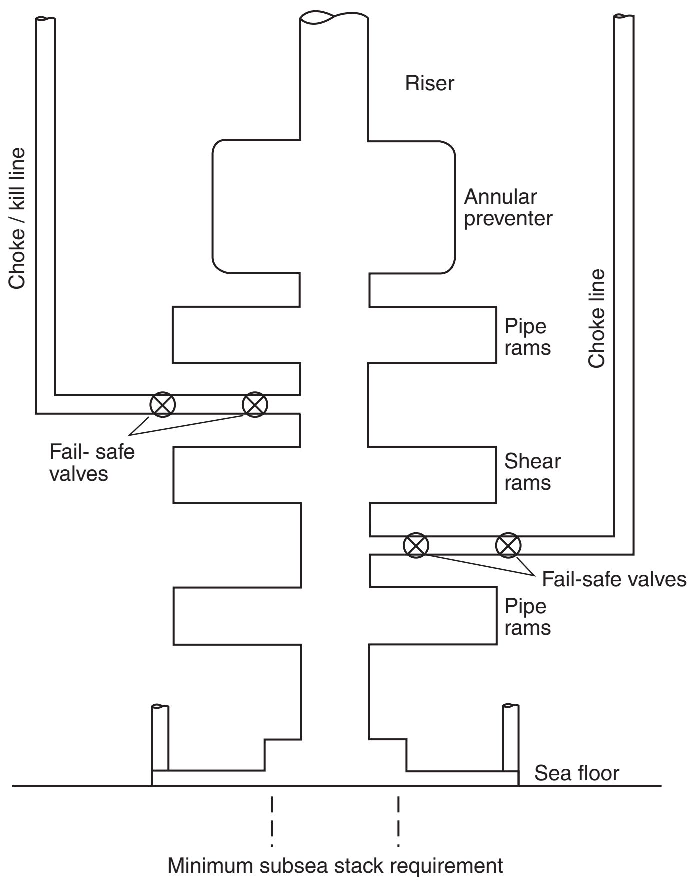


Fig. 4.31 Schematic of a minimum subsea stack.

minimum subsea stack requirement. Most operators use a double-annular preventer configuration with a connector in between. The connector allows for the top package to be pulled and the top annular preventer to be repaired. The lowermost annular preventer is used as a backup when the top annular preventer fails.

Shear rams, as opposed to blind rams, are a necessity in the event that conditions dictate that the drill string must be sheared and the drilling vessel moved off location. Most subsea stacks contain 4–6 rams. Ram placement should be determined by a risk assessment.

The list of alternate stack arrangements is endless, and it would be pointless to list the advantages and disadvantages of each. In many cases, the operator has no choice but to take the stack that comes with the rig. When a choice is available, the operator should review the potential problems in his area to determine the stack arrangement that best suits his needs, with the underlying requirement being redundancy on all critical components.

Accumulator bottles are usually mounted on the subsea stack to improve response time or to activate the BOP stack acoustically in the event of an emergency when a ship is moved off location. In these instances, the precharge pressure requires adjusting to account for the hydrostatic pressure in the control lines or

$$P_{pc} = P_{inipc} + 14.7 + (l_{contline})(S_g)(0.433) \tag{4.32}$$

where

P_{pc} = precharge pressure, psi
P_{inipc} = initial precharge pressure, psi
$l_{contline}$ = length of control line, ft
S_g = specific gravity

The use of higher precharge pressure also results in a reduction in the usable volume of an accumulator bottle. It therefore follows that more bottles than normal are required. Using the ideal gas law and equating volumes at precharge, minimum, and maximum operating pressure,

$$\frac{P_{pc}V_{pc}}{z_{pc}T_{sc}} = \frac{P_{\min}V_{\min}}{Z_{\min}T_{ss}} = \frac{P_{\max}V_{\max}}{z_{\min}T_{ss}}$$

where

ss = subsea
pc = precharge
min = minimum

max = maximum
sc = standard conditions
P = pressure, psi
V = volume, bbl
z = compressibility factor
T = temperature, degrees absolute

The usable volume per bottle is then $V_{min}-V_{max}$.

Spacing Out

Due to the problems associated with pressure surge in the system and wear on the preventers associated with heave on semisubmersibles and drillships, the drill string is usually hung off on the upper pipe rams when the heave becomes excessive. The distance to the rams should be calculated after the riser has been run to ensure that the rams do not close on a tool joint. To do this, run in hole, position the tool joint 15 ft above the upper rams, close the upper rams, and slowly lower the drill string until the rams take the weight of the string. Record the tide and distance to the tool joint below the rotary table for future reference.

Shut-in Procedures

Classical shut-in procedures are modified because of the special considerations of floating drilling operations with a subsea stack. Some of the modifications are as follows:

A. While drilling
1. At the first indication of a kick, stop the mud pumps. Close the BOPs and, if conditions dictate, hang off as described in the previous section.
2. Notify the tool pusher and company representative.
3. Read and record the pit gain, shut-in drill pipe pressure and shut-in casing pressure.

B. While tripping
1. At the first indication of a kick, set the slips and install and close the drill pipe safety valve.
2. Close the BOPs and connect the top drive. If conditions dictate, hang off as described in the previous section.
3. Notify the tool pusher and company representative.
4. Open the safety valve and read and record the pit gain, shut-in drill pipe pressure and shut-in casing pressure.

Floating Drilling Well Control Problems

There are four well control problems peculiar to floating drilling operations. They are the following:

1. Fluctuations in flow rate and pit volume due to the motion of the vessel
2. Friction loss in the choke line
3. Reduced fracture gradient
4. Gas trapped in BOP stack after circulating out a kick

Fluctuations in Flow Rate and Pit Volume

Due to the heaving of the vessel and the related change in volume of the riser on floaters, the flow rate and pit volume fluctuate, making these primary indications of a kick difficult to interpret. Monitoring the pit volume for indications of a kick is further complicated by the pitch and roll of the vessel, as this will cause the fluid in the pits to "slosh" with the motion of the vessel—even if there is no fluid flow in or out of the pits.

Many techniques have been proposed to decrease the effect of vessel movement. The pit volume totalizer, as opposed to the mechanical float, is a step in the right direction, but it requires infinite sensors to compensate totally for the entire range of vessel motion. An electronic seafloor flow rate indicator has been devised to alleviate the problem of vessel movement. The idea is sound, but experience with this equipment is limited. For now, the industry will have to continue to monitor the surface equipment for changes in the trend. Naturally, this causes a delay in the reaction time and allows a greater influx. Knowing this, the rig personnel must be particularly alert to other kick indicators.

Frictional Loss in the Choke Line

Frictional pressure losses in the small internal diameter (ID) choke line are negligible on land rigs but can be significant in deepwater subsea stack operations. The degree is proportional to the length and ID of the choke line. For the land rig U-tube dynamic model, the bottom-hole pressure, P_b, is equal to the hydrostatic of the annulus fluids, ρ_m, plus the choke back pressure, P_{ch1}:

$$P_b = \rho_m D + P_{ch1}$$

Normally, the equivalent circulating density (ECD) resulting from frictional pressure losses in the annulus is not considered since it is difficult to calculate, positive, and minimal. However, in the case of a long choke line, the effects are dramatic, particularly during a start-up and shut-down operation.

With the long, small choke line, the dynamic equation becomes bottom-hole pressure equals the hydrostatic of the annulus fluids, ρ_m, plus the choke back pressure, P_{ch2}, plus the friction loss in the choke line, P_{fcl}:

$$P_b = \rho_m D + P_{ch2} + P_{fcl}$$

Solving the equations simultaneously results in

$$P_{ch1} = P_{ch2} + P_{fcl}$$

or

$$P_{ch2} = P_{ch1} - P_{fcl}$$

Simply said, the pressure on the choke at the surface must be reduced by the frictional pressure in the choke line. The need to understand this concept is paramount because, if the choke operator controls the back pressure to equal shut-in casing pressure during start-up, an additional and unnecessary pressure will be imposed on the open-hole formations equal to the choke line frictional pressure, P_{fcl}, often with catastrophic results.

On the other hand, if the operator maintains choke pressure constant during a shut-in operation, the choke line friction pressure is reduced to 0, reducing the bottom-hole pressure by the choke line friction pressure, P_{fcl}, and allowing an additional influx.

There is a very simple solution, one that has gained acceptance in the industry. During any operation when the pump rate is changed, including start-up and shut-in operations, monitor the secondary choke line pressure and operate the choke to maintain this pressure constant. Since the choke line pressure loss is above the stack, then

$$P_b = \rho_m D + P_{ch2}$$

Therefore, monitor the secondary choke line pressure in the same manner that the primary choke back pressure (also called casing or annulus) on a land rig is monitored. The choke gauge must still be monitored for evidence of plugging.

Reduced Fracture Gradient

The classical works done in fracture gradient determination were developed for land operations and cannot be applied directly to offshore operations. The fracture gradient offshore will normally be less than an onshore gradient at equivalent depth as a result of the reduction in total overburden stress due to the air gap and seawater gradient.

Various charts and procedures have been developed for specific areas to modify the classical methods (Eaton, Kelly and Matthews, etc.) for offshore use. The basic premise is to reduce the water depth to an equivalent section of formation by the ratio of the seawater gradient to the overburden stress gradient at the point of interest. When using these charts, it is important to realize that some are referenced by the ratio of the subsea depth to the depth rotary table (or RKB). Consider Example 4.12:

Example 4.12

Given:

Depth at shoe = 2600 ft rotary table
Water depth = 500 ft
Air gap = 100 ft

Required:

Determine the fracture gradient at the shoe.

Solution:

Sediment thickness = 2600 − 500 − 100 = 2000 ft
Fracture pressure from Fig. 4.32 = 1500 psi

$$F_g = \frac{1500}{(2600)(0.052)}$$

$$F_g = \mathbf{11.1\,ppg}$$

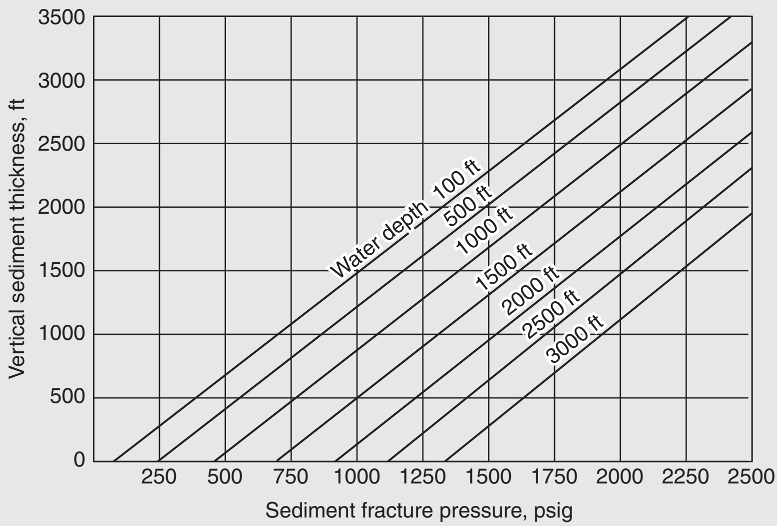


Fig. 4.32 Estimated Fracture Pressure for Marine Sediments. *(Courtesy LSU.)*

Trapped Gas After Circulating Out a Kick

Most BOP stack arrangements do not provide for the removal of the gas bubble remaining between the annular preventer and the choke line after circulating out a kick. This presents no problem in surface operations, as the pressure of this gas is minimal. However, with the use of subsea stacks, the pressure of this gas bubble is equal to the hydrostatic weight of the kill mud existing in the choke line. If improperly handled, the expansion of this bubble after opening the BOP could result in an extremely hazardous situation. Closing the lowest pipe ram to isolate the hole while displacing kill-weight mud into the riser via the kill line with the diverter closed is an acceptable method in more shallow situations. A more conservative method for deeper situations is recommended as follows:

After circulating out all kicks, do the following:

1. Close the lower pipe rams and calculate the difference in pressure between the hydrostatic head of the kill mud versus a column of water in the choke line.
2. Displace the kill-weight mud in the BOP stack and choke line with water pumped down the kill line while holding the back pressure calculated in step 1.
3. Close the kill-line valve and bleed the pressure off through the gas buster.
4. Close the diverter and open the annular preventer, allowing the remaining gas to U-tube up the choke line to the gas buster.
5. Displace the mud in riser with kill-weight mud via kill line.
6. Open lower pipe rams.

Deep-Water Floating Drilling

Well control principles are no different for operations in deep water. A well is deep and dumb and doesn't have any idea how much water, if any, is between the wellhead and the producing formation. However, with the increase in deepwater operations, a kind of mystic veil has evolved.

Some aspects of well control operations in deep water discourage and/or compromise classical well control procedures. However, there is no mystery. The laws of physics and chemistry still apply. The general philosophy among most operators seems to be to keep the problems below the casing seat.

As the water depth increases, the margin between fracture gradient and pore pressure generally decreases. Therefore, more drilling liners are required to maintain any reasonable kick tolerance.

As the water depth increases, the length of the choke line and, of course, the frictional pressure loss in the choke line increase proportionally. These conditions make circulating out a kick without losing circulation a slow, difficult, and delicate (and often impossible) process.

The length of the choke line introduces other complications in addition to added friction. Because the frictional pressure loss is a function of the fluid properties, the frictional pressure loss with gas or gas-cut mud in the choke line can be significantly different than that determined with only mud. In addition, the annulus pressure has been known to fluctuate erratically with gas-cut mud in the choke line, making keeping the drill pipe pressure constant very difficult.

As the choke line lengthens, the length of the gas column increases, resulting in higher surface pressures. Consequently, there is a reluctance to bring gas into the choke line and to the surface. Consider the following example.

Example 4.13

The maximum annular pressure will occur when the gas bubble first reaches the surface and is given by the following expression:

$$P_{s\max} = \frac{B_s + \left[B_s^2 + 4A_sX_s\right]^{\frac{1}{2}}}{2A_s} \tag{4.33}$$

where

$$A_s = 1 + \rho_m l_{cl}\left(1 - \frac{C_{cl}}{C_h}\right)\left(\frac{S}{53.3Z_sT_s}\right)$$

$$B_s = P_b - \rho_m D + \rho_m l_{cl}\left(1 - \frac{C_{cl}}{C_h}\right) + \frac{S\rho_m P_b h_b}{53.3Z_bT_b}$$

$$X_s = \frac{\rho_m P_b Z_s T_s h_b}{Z_b T_b}$$

s = at surface
b = at bottom of the hole
ρ_m = mud density, psi/ft
l_{cl} = length of choke line, ft
C_{cl} = capacity of choke line, bbl/ft
C_h = capacity of annulus beneath BOPs, bbl/ft
S = specific gravity of the gas
P = pressure, psi
Z = compressibility

Example 4.13—cont'd

T = temperature, °R

h_b = height of initial influx with geometry beneath BOPs

Assumptions This equation assumes that the Driller's method is used for displacement of the influx. Therefore, it is a "worst-case" scenario. In order to eliminate the complexities introduced by different geometries between the bottom of the hole and the blowout preventers, the height of the influx, h_b, is determined using the geometry of the annulus immediately below the blowout preventers.

Consider Fig. 4.33 and the following:

Gas specific gravity = 0.6

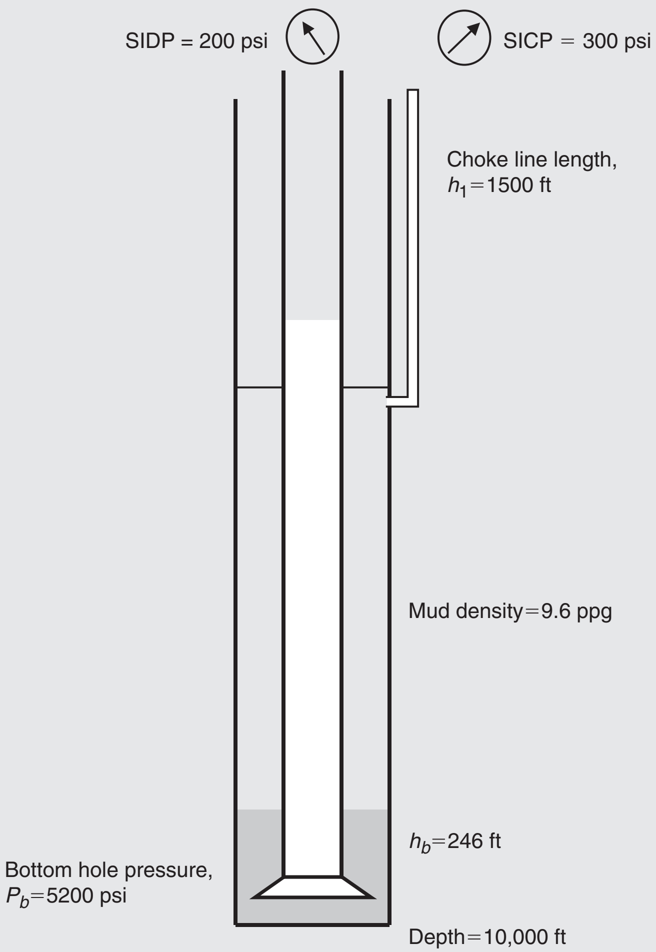


Fig. 4.33 Offshore well with subsea stack after kick.

Continued

Example 4.13—cont'd

Influx height = 246 ft
Bottom-hole temperature = 640°R
Surface temperature = 535°R
Compressibility at bottom-hole and surface conditions = 1.0
Bottom-hole pressure = 5200 psi
Mud density = 9.6 ppg
Length of choke line = 1500 ft
Capacity of choke line = 0.0087 bbl/ft
Capacity of annulus = 0.0406
Depth = 10,000 ft

Substituting these values into Eq. (4.33), the pressure when the gas reaches the surface is determined to be

$$P_{smax} = 1233 \text{ psi}$$

This same problem was solved in Example 4.8 using the Driller's method for a constant annular area to the surface. In that example, the maximum surface pressure was determined to be 759 psi. Therefore, the 1500 ft of small-diameter choke line would add 474 psi to the surface pressure (Fig. 4.34).

As deepwater floating drilling operations become more routine, the comfort level in well control operations will rise. The BOP equipment is generally very reliable. The general procedure should include a "pain threshold pressure." When that pressure is reached, the influx can still be bullheaded to the casing or liner shoe.

As of this writing, most influxes are "sandwiched." The hole is displaced simultaneously through both the drill pipe and the annulus, thereby "sandwiching" the influx into the lost zone at the shoe. Although this procedure is arbitrary, it has enjoyed a fair amount of success.

In addition, the sediments exposed in deep water are usually very young. Therefore, there is a very good chance that the well will bridge around the bottom-hole assembly and kill itself.

Deep water can be an asset in the event of a catastrophic failure. Consider the consequences of a dramatic failure that results in a discharge at the seafloor. In shallow water, the boil will be in the immediate proximity of the vessel. Alternatives for further operations are compromised or eliminated. In deep water, a similar situation would most likely not have such alarming results. If the water depth is sufficient, the current will move the boil a

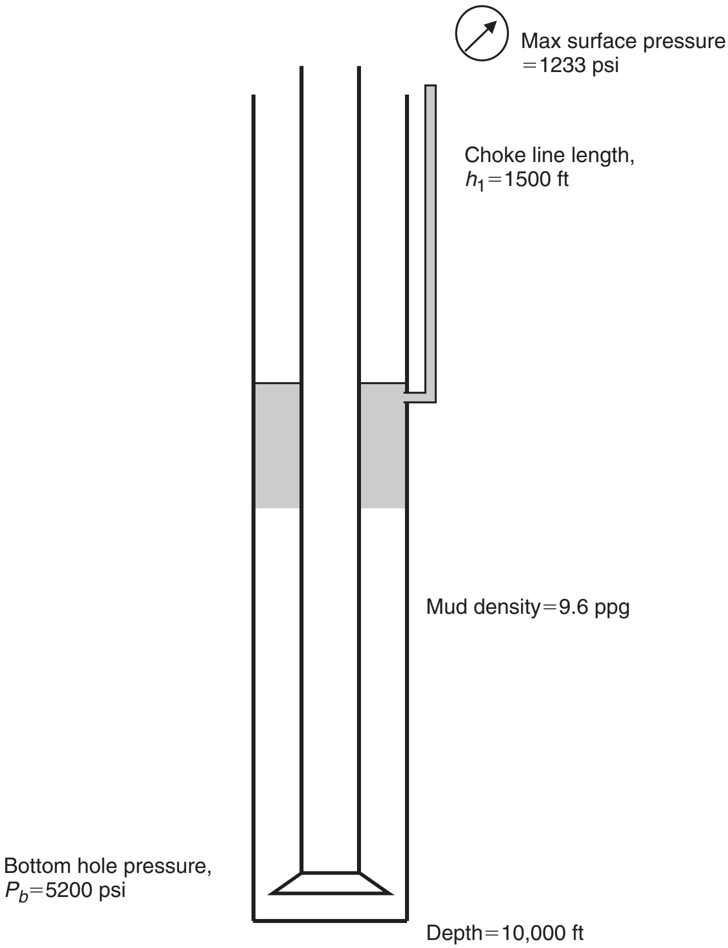


Fig. 4.34 Offshore well with subsea stack and gas at the surface.

substantial distance away from the vessel, and alternatives should be more numerous.

Shallow Gas Kicks

Shallow gas blowouts can be catastrophic. There is not a perfect technique for handling shallow gas blowouts. There are basically two accepted methods for handling a shallow gas kick, and the difference centers on whether the gas is diverted at the seafloor or at the surface. Operators are evenly divided between the two methods and equally dedicated to their favorite.

The disadvantage to diverting the gas at the seafloor, particularly when operating in deep water and controlling it via the choke line(s), is the additional back pressure exerted on the casing seat due to the frictional pressure drop in the choke line system.

The disadvantage of diverting the gas at the surface, particularly when operating in deep water, is the possibility of collapsing the marine riser when rapid gas expansion evacuates the riser. In addition, the gas is brought to the rig floor. Surface sands are usually unconsolidated, and severe erosion is certain. Plugging and bridging are probable in some areas and can result in flow outside the casing and in cratering. Advances in diverters and diverter system design have improved surface diverting operations substantially.

NEGATIVE TESTS

Negative tests are common in all drilling operations. They are used in land-based operations to insure liner top integrity and in deepwater operations prior to removing the riser. There is little reason for a negative test to be inconclusive provided basic rules are followed.

Assume the isolation of a liner top is to be evaluated. The simple procedure would be to run and set a packer near the top of the liner. The bypass would be opened, and the tubing or drill pipe would then be displaced with a fluid (usually water) with density such that there would be a negative pressure differential between the formation pressure and the hydrostatic column of the fluid inside the tubing or drill pipe. The bypass in the packer would then be closed. The annulus between the tubing/drill pipe could then be pressured to assure the inside of the tubing/drill pipe is isolated.

Of course, due to the hydrostatic imbalance between the tubing/drill pipe and the annulus, there will be pressure on the tubing/drill pipe when the bypass is closed. The compressibility of the fluid inside the tubing/drill pipe should be predetermined along with the anticipated volume of fluid that will be recovered when the tubing/drill pipe is opened and bled back at the surface.

Once all of this has been done, it is a simple matter to open the tubing/drill pipe to a tank where the return volume can be measured. The flow at the surface should stop once the calculated volume has been recovered. At that point, the well should be static. Usually, the well should be observed to remain static for a period of time between 5 and 30 min. After the allotted time has passed, the well can then be shut in and observed for an additional 5–30 min for any indication of pressure buildup.

If there is continued flow in excess of the predetermined volume or if there is pressure buildup after the well has been shut in, the well has failed the negative pressure test, and the operation should not be continued until the situation is resolved.

In floating drilling operations, the aforementioned procedure using a packer on drill pipe as previously described is fool proof and is the recommended procedure. However, operators and drilling contractors often elect to use the subsea stack to isolate the drill pipe. In that procedure, the drill pipe is displaced as described above, and an annular preventer is utilized in place of a packer. It must be remembered that most annular blowout preventers are designed to maintain pressure integrity from below—not from above. Therefore, if the annular leaks, there will be flow at the surface when the drill pipe is opened and pressure at the surface when the valve on the drill pipe is closed reflecting the hydrostatic imbalance.

In some instances, the operator prefers to use the choke or kill line to conduct the negative test. The choke or kill line should not be used as there are simply too many possibilities for hydrostatic imbalance to occur and cause the results to be ambiguous.

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CHAPTER FIVE

Fluid Dynamics in Well Control

29 June

0051 hours—reached casing setting depth of 3200 ft. Circulated for 5 min and pulled one stand. Made flow check—no flow.

0130 hours—circulated and prepare for trip.

0200 hours—pulled three stands and made flow check. No flow.

0230 hours—pulled 16 stands. Fluid level ceased to drop while pulling first one half of 16th stand. Mud flowing back on last half of 16th stand. Pulled 17th stand with well flowing back. Driller could hear mud flowing over the blowout preventer and drilling nipple at a very high rate.

0233 hours—latched 18th stand, picked up 5 ft and shut in the well. Crew realized there was a kick.

0236 hours—pressure exceeded maximum allowable shut in casing pressure. Opened well. Within 15 min leaks were observed in the panic line and in the flare lines downstream from the choke manifold.

0700 hours—pumped kill mud with no effect on flow from well. Continued to flow well throughout the day.

1930 hours—a leak developed in the choke line. Pumped a second kill attempt.

2004 hours—panic line failed at the wellhead.

2045 hours—gas cloud drifted toward flare pit and ignited all the gas around the rig.

The use of kill fluids in well control operations is not new. However, one of the newest technical developments in well control is the engineered application of fluid dynamics. The technology of fluid dynamics is not fully utilized because most personnel involved in well control operations do not understand the engineering applications and do not have the capabilities to apply the technology at the rig in the field. The best well control procedure is the one that has predictable results from a technical and a mechanical perspective.

Blowout and Well Control Handbook
http://dx.doi.org/10.1016/B978-0-12-812674-5.00005-5

Fluid dynamics have an application in virtually every well control operation. Appropriately applied, fluids can be used cleverly to compensate for unreliable tubulars or inaccessibility. Often, when blowouts occur, the tubulars are damaged beyond expectation. For example, at a blowout in Wyoming, an intermediate casing string subjected to excessive pressure was found by survey to have failed in NINE places [1]. One failure is understandable. Two failures are imaginable, but NINE failures in one string of casing?

After a blowout in South Texas, the $9\frac{5}{8}$ in. surface casing was found to have parted at 3200 ft and again at 1600 ft. Combine conditions such as those just described with the intense heat resulting from an oil-well fire or damage resulting from a falling derrick or collapsing substructure, and it is easy to convince the average engineer that after a blowout the wellhead and tubulars could be expected to have little integrity. Properly applied, fluid dynamics can offer solutions that do not challenge the integrity of the tubulars in the blowout.

The applications of fluid dynamics to be considered are the following:

1. Kill-fluid bullheading
2. Kill-fluid lubrication
3. Dynamic kill
4. Momentum kill

KILL-FLUID BULLHEADING

"Bullheading" is the pumping of the kill fluid into the well against any pressure and regardless of any resistance the well may offer. Kill-fluid bullheading is one of the most common misapplications of fluid dynamics. Because bullheading challenges the integrity of the wellhead and tubulars, the result can cause further deterioration of the condition of the blowout. Many times, wells have been lost, control delayed, or options eliminated by the inappropriate bullheading of kill fluids.

Consider the following for an example of a proper application of the bullheading technique. During the development of the Ahwaz Field in Iran in the early 1970s, classical pressure control procedures were not possible. The producing horizon in the Ahwaz Field is so prolific that the difference between circulating and losing circulation is a few psi. The typical wellbore schematic is presented as Fig. 5.1.

Drilling in the pay zone was possible by delicately balancing the hydrostatic with the formation pore pressure. The slightest underbalance resulted

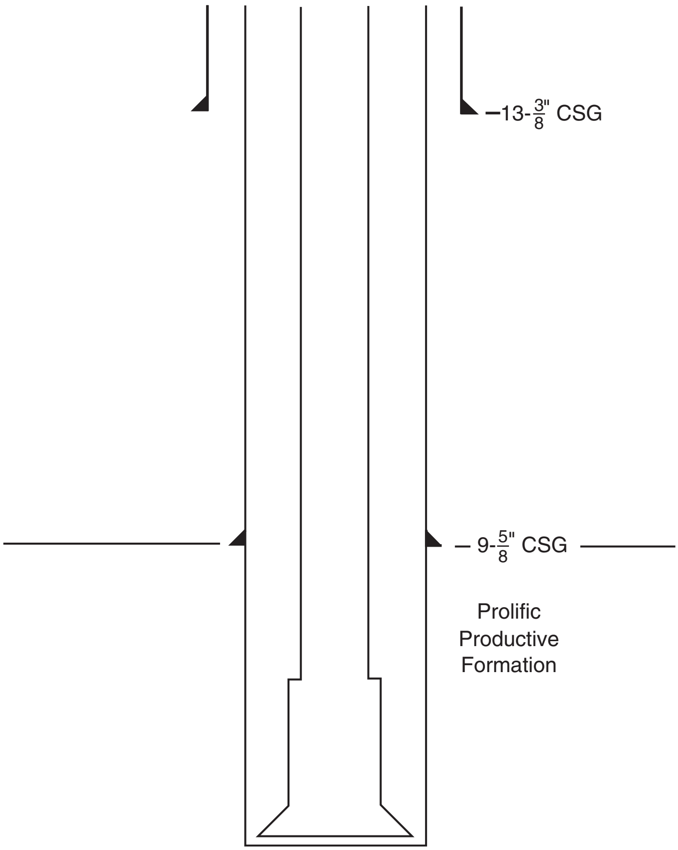

Fig. 5.1 Typical well in Ahwaz Field.

in a significant kick. Any classic attempt to control the well was unsuccessful because even the slightest back pressure at the surface caused lost circulation at the $9\frac{5}{8}$ in. casing shoe. Routinely, control was regained by increasing the weight of two hole volumes of mud at the surface by 1–2 ppg and pumping down the annulus to displace the influx and several hundred barrels of mud into the productive formation. Once the influx was displaced, routine drilling operations were resumed.

After the blowout at the Shell Cox in the Piney Woods of Mississippi, a similar procedure was adopted in the deep Smackover tests. In these operations, bringing the formation fluids to the surface was hazardous due to the high pressures and high concentrations of hydrogen sulfide. In response to the challenge, casing was set in the top of the Smackover. When a kick was taken, the influx was overdisplaced back into the Smackover by bullheading kill-weight mud down the annulus.

The common ingredients of success in these two examples are pressure, casing seat, and kick size. The surface pressures required to pump into the formation were low because the kick sizes were always small. In addition, it was of no consequence that the formation was fractured in the process and damaged by the mud pumped. The most important aspect was the casing seat. The casing that sat at the top of the productive interval in each example ensured that the kill mud and the influx would be forced back into the interval from which the kick occurred. It is most important to understand that, when bullheading, the kill fluid will almost always exit the wellbore at the casing seat.

Consider an example of misapplication from the Middle East:

Example 5.1
Given:
Fig. 5.2

Depth, $D = 10{,}000$ ft
Mud weight, $\rho = 10$ ppg
Mud gradient, $\rho_m = 0.52$ psi/ft
Gain $= 25$ bbl
Hole size, $D_h = 8\frac{1}{2}$ in.
Intermediate casing ($9\frac{5}{8}$ in.) $= 5000$ ft
Fracture gradient, $F_g = 0.65$ psi/ft
Fracture pressure:
at 5000 ft, $P_{frac5000} = 3250$ psi
at 10,000 ft, $P_{frac10000} = 6500$ psi
Shut-in annulus pressure, $P_a = 400$ psi
Drill pipe $= 4\frac{1}{2}$ in.
Internal diameter, $D_i = 3.826$ in.
Drill collars $= 800$ ft
Drill collars=6 in. $\times$ 2.25 in.
Gas specific gravity, $S_g = 0.60$
Temperature gradient $= 1.2°/100$ ft
Ambient temperature $= 60°$F
Compressibility factor, $z = 1.00$
Capacity of
Drill collar annulus, $C_{dcha} = 0.0352$ bbl/ft
Drill pipe, $C_{dpha} = 0.0506$ bbl/ft

The decision was made to weight up the mud to the kill weight and displace down the annulus since the drill pipe was plugged.

Example 5.1—cont'd

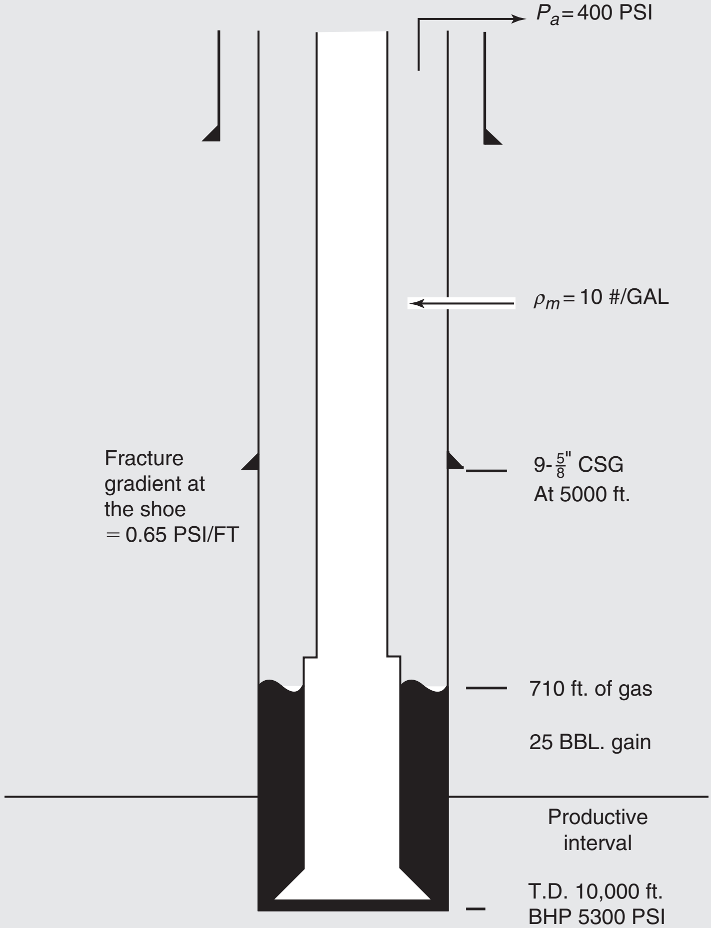

Fig. 5.2 Wellbore schematic of kick in Example 5.1.

From Fig. 5.2 and Eq. (2.7),

$$P_b = \rho_f h + \rho_m (D - h) + P_a$$

and from Eq. (3.7),

$$h_b = \frac{\text{Influx Volume}}{C_{dcha}}$$

$$h_b = \frac{25}{0.0325}$$

$$h_b = \mathbf{710\,ft}$$

and from Eq. (3.5),

Continued

Example 5.1—cont'd

$$\rho_f = \frac{S_g P_b}{53.3 z_b T_b}$$

$$\rho_f = \frac{(0.6)(5200)}{53.3(1.0)(640)}$$

$$\rho_f = \mathbf{0.091\ psi/ft}$$

Therefore,

$$P_b = 400 + 0.52(10,000 - 710) + (0.091)(710)$$
$$P_b = \mathbf{5295\ psi}$$

The kill-mud weight would then be given from Eq. (2.9):

$$\rho_1 = \frac{P_b}{0.052D}$$

$$\rho_1 = \frac{5295}{(10,000)(0.052)}$$

$$\rho_1 = \mathbf{10.2\ ppg}$$

The annular capacity

$$\text{Capacity} = (9200)(0.0506) + (800)(0.0352)$$
$$\text{Capacity} = \mathbf{494\ bbls}$$

As a result of these calculations, 500 bbl of mud was weighted up at the surface to the kill weight of 10.2 ppg and pumped down the annulus. After pumping the 500 bbl of 10.2 ppg mud, the well was shut in and surface pressure was observed to be 500 psi, or 100 psi more than the 400 psi originally observed!

Required:

1. Explain the cause of the failure of the bullhead operation.
2. Explain the increase in the surface pressure.

Solution:

1. The pressure at 5000 ft is given by

$$P_{5000} = (0.052)(10.0)(5000) + 400$$
$$P_{5000} = \mathbf{3000\ psi}$$

The fracture gradient at 5000 ft is 3250 psi. Therefore, the difference is

$$\Delta P_{5000} = 3250 - 3000$$
$$\Delta P_{5000} = \mathbf{250\ psi}$$

The pressure at 10,000 ft is 5296 psi. The fracture gradient at 10,000 ft is 6500 psi. Therefore, the difference is

$$\Delta P_{10000} = 6500 - 5296$$
$$\Delta P_{10000} = \mathbf{1204\ psi}$$

Example 5.1—cont'd

The pressure required to pump into the zone at the casing shoe was only 250 psi above the shut-in pressure and 954 psi less than the pressure required to pump into the zone at 10,000 ft. Therefore, when pumping operations commenced, the zone at the casing seat fractured and the mud was pumped into that zone.

2. The surface pressure after the bullheading operation was 100 psi more than the surface pressure before the pumping job (500 psi vs 400 psi) because the 25 bbl influx had risen during the pumping operation. (See Chapter 4 for a further discussion of bubble rise.)

There are other reasons that a bullheading operation can fail. For example, after a well has been shut in, the influx often migrates to the surface, leaving the drilling mud opposite of the kick zone. Once pumping begins, the surface pressure must be increased until the zone to be bullheaded into is fractured by the drilling mud. The fracture pressure may be several hundred to several thousand pounds per square inch above the shut-in pressure. This additional pressure may be enough to rupture the casing in the well and cause an underground blowout.

Sometimes, bullheading operations are unsuccessful when an annulus in a well is completely filled with gas that is to be pumped back into the formation. The reason for the failure in an instance such as this is that the kill mud bypasses the gas in the annulus during the pumping operation. Therefore, after the kill mud is pumped and the well is shut in to observe the surface pressure, there are pressure at the surface and gas throughout the system. The result is that the well unloads and blows out again.

Another consideration is the rate at which the mud being bullheaded is pumped. In the discussion concerning influx migration, it was noted that the influx usually migrates up one side of the annulus while the mud falls down the other side of the annulus. Further, when the influx nears the surface, the velocity of migration can be very high, as evidenced by the rate of surface pressure increase. Under those conditions, bullheading at $\frac{1}{4}$ bbl/min will not be successful because the mud will simply bypass the migrating influx. This is particularly problematic when the annulus area is large. The bullheading rate may have to be increased to more than 10 bbl/min in order to be successful. In any event, the bullheading rate will have to be increased until the shut-in surface pressure is observed to be decreasing as the mud is bullheaded into the annulus.

Bullheading is often used in deep, high-pressure well control situations to maintain acceptable surface pressures. Consider Example 5.2 during underground blowouts:

Example 5.2
Given:
Depth, $D = 20{,}000$ ft
Bottom-hole pressure, $P_b = 20{,}000$ psi
Casing shoe at, $D_{shoe} = 10{,}000$ ft
Fracture gradient at shoe, $F_g = 0.9$ psi/ft
The production is gas, and the well is blowing out underground.

Required:
Approximate the surface pressure if the gas is permitted to migrate to the surface.
Determine the surface pressure if 15 ppg mud is continuously bullheaded into the annulus.

Solution:
If the gas is permitted to migrate to the surface, the surface pressure will be approximately as follows:

$$P_{surf} = \left(F_g - 0.10\right) D_{shoe}$$
$$P_{surf} = (0.90 - 0.10)(10,000)$$
$$P_{surf} = \mathbf{8000\ psi}$$

With 15 ppg mud bullheaded from the surface to the casing shoe at 10,000 ft, the surface pressure would be

$$P_{surf} = 8000 - (0.052)(15)(10,000)$$
$$P_{surf} = \mathbf{200\ psi}$$

Therefore, as illustrated in Example 5.2, without the bullheading operation, the surface pressure would build to 8000 psi. At that pressure surface operations are very difficult at best. If 15 ppg mud is bullheaded into the lost circulation zone at the casing shoe, the surface pressure can be reduced to 200 psi. With 200 psi surface pressure, all operations such as snubbing or wire line are considerably easier and faster.

A deep well in the southern United States got out of control while tripping. The conditions and wellbore schematic are presented in Fig. 5.3.

Since there was only 173 ft of open hole, it was concluded that the well would probably not bridge. However, when the cast iron bridge plug was set inside the drill pipe in preparation for stripping in the hole, the flow began to

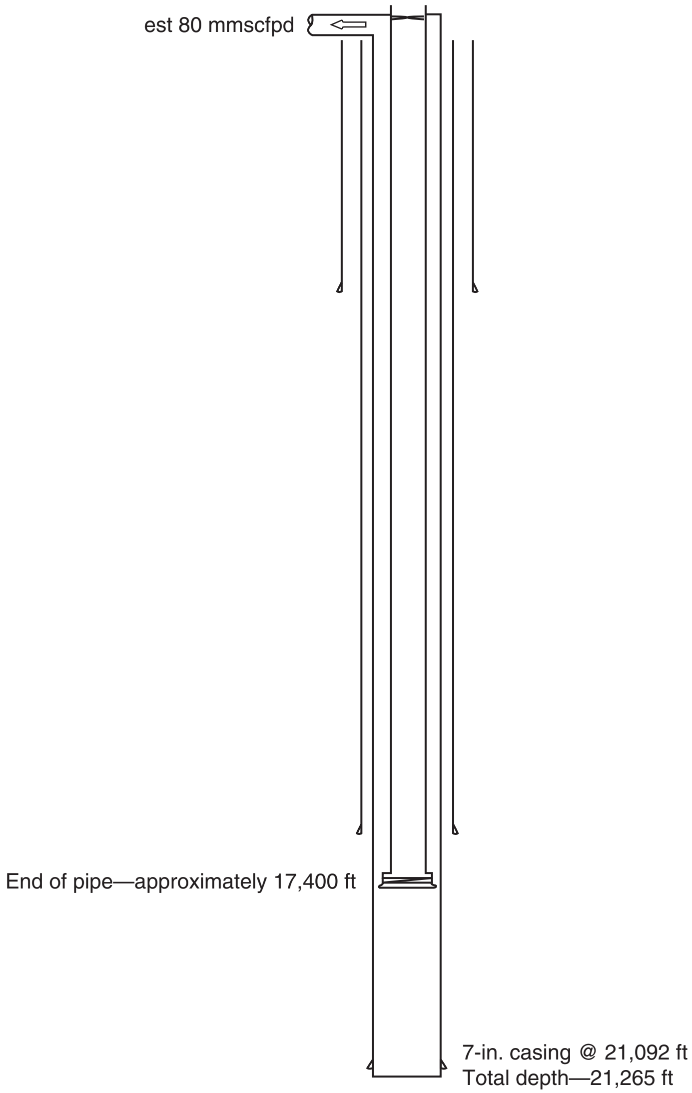

Fig. 5.3 Wellbore schematic for a deep well in the southern United States.

diminish. Within the hour, the flow declined to a small, lazy flare. The well had obviously bridged.

The primary question at that point was the location of the bridge. Normally, bridging occurs in the bottom-hole assembly. The velocity is low deep in the well adjacent to the bottom-hole assembly. The changes in diameter provide opportunity for the accumulation of formation particulate.

In this case, drill pipe protector rubbers had been used. It is not unusual for protector rubbers to be problematic in the presence of high temperature gas. Due to the presence of the rubbers, the bridge could be high in the well.

A deep bridge would be acceptable since sufficient hydrostatic could be placed above the bridge to compensate for the high formation pressure. A shallow bridge would be very dangerous since full shut-in pressure could easily be immediately below the surface and held only by a few feet of packed debris.

Since the well was continuing to produce a small quantity of gas, it was considered that a temperature survey could identify the bridge. It was anticipated that the expansion of the gas across the bridge would result in a significant temperature anomaly. Accordingly, a temperature survey was run and is presented as Fig. 5.4. As illustrated in Fig. 5.4, interpretation of the temperature indicated that the bridge was around the bottom-hole assembly. Accordingly, the annulus was successfully loaded with 432 bbl (the calculated volume was 431 bbl) of 20 ppg mud.

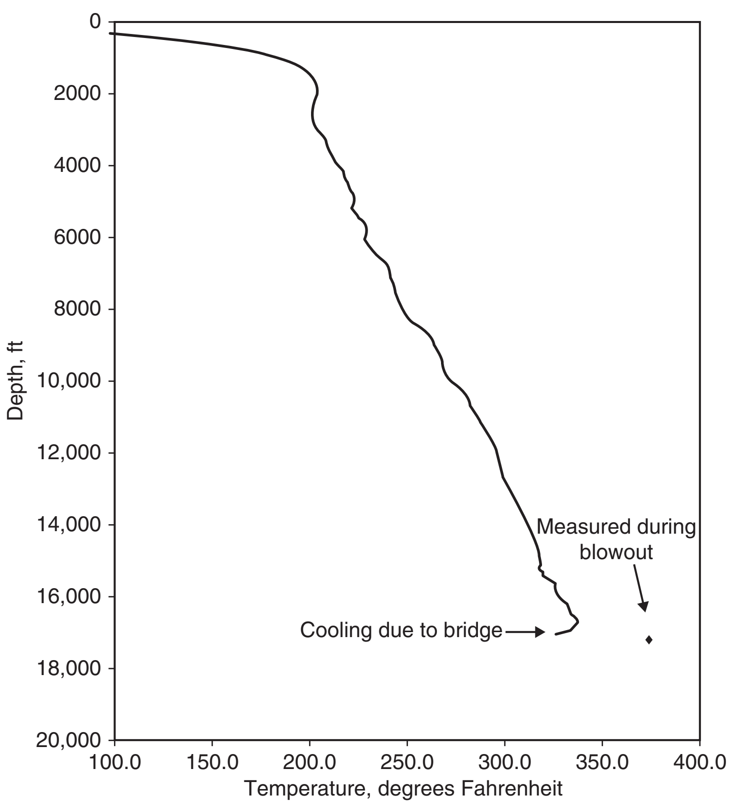

Fig. 5.4 Temperature analysis after well bridged, August 13, 1998.

In summary, bullheading operations can have unpleasant results and should be thoroughly evaluated prior to commencing the operation. Too often, crews react to well control problems without analyzing the problem and get into worse condition than when the operation began. Remember, the best well control procedure is one that has predictable results from the technical and the mechanical perspective.

KILL-FLUID LUBRICATION—VOLUMETRIC KILL PROCEDURE

Kill-fluid lubrication, also sometimes called the lube and bleed method, is the most overlooked well control technique. Lubricating the kill fluid into the wellbore involves an understanding of only the most fundamental aspects of physics. The gas is allowed to expand using the volumetric method as the gas migrates to the surface. Once the gas is at the surface, the lube and bleed method is used to replace the gas with mud. Basically, kill-fluid lubrication is a technique whereby the influx is replaced by the kill fluid while the bottom-hole pressure is maintained at or above the formation pressure. The result of the proper kill-fluid lubrication operation is that the influx is removed from the wellbore, the bottom-hole pressure is controlled by the kill-mud hydrostatic, and no additional influx is permitted during the operation.

Kill-fluid lubrication has application in a wide variety of operations. The only requirement is that the influx has migrated to the surface or, as in some instances, the wellbore is completely void of drilling mud. Kill-fluid lubrication has application in instances when the pipe is on bottom, the pipe is partway out of the hole, or the pipe is completely out of the hole. The technique is applicable in floating drilling operations where the rig is often required, due to weather or some other emergency, to hang off, shut in, and move off the hole. In each instance, the principles are fundamentally the same.

Consider the following from a recent well control problem at a deep, high-pressure operation in southeastern New Mexico. A kick was taken while on a routine trip at 14,080 ft. The pipe was out of the hole when the crew observed that the well was flowing. The crew ran 1500 ft of drill string back into the hole. By that time, the well was flowing too hard for the crew to continue the trip into the hole, and the well was shut in. A sizable kick had been taken. Subsequently, the drill pipe was stripped into the hole in preparation for a conventional kill operation.

However, the back-pressure value, placed in the drill string 1500 ft above the bit to enable the drill pipe to be stripped into the hole, had become plugged during the stripping operation. In addition, during the time the snubbing unit was being rigged up and the drill pipe was being stripped to bottom, the gas migrated to the surface. The influx came from a prolific interval at 13,913 ft. The zone had been drill-stem tested in this wellbore and had flowed gas at a rate of 10 mmscfpd with a flowing surface pressure of 5100 psi and a shut-in bottom-hole pressure of 8442 psi.

Since it was not possible to circulate the influx out of the wellbore in a classic manner, kill fluid was lubricated into the wellbore, while efforts were being made to remove the obstruction in the drill pipe. The conditions as they existed at this location on that pleasant November afternoon are schematically illustrated in Fig. 5.5. The following example illustrates the proper procedure for lubricating kill fluid into a wellbore:

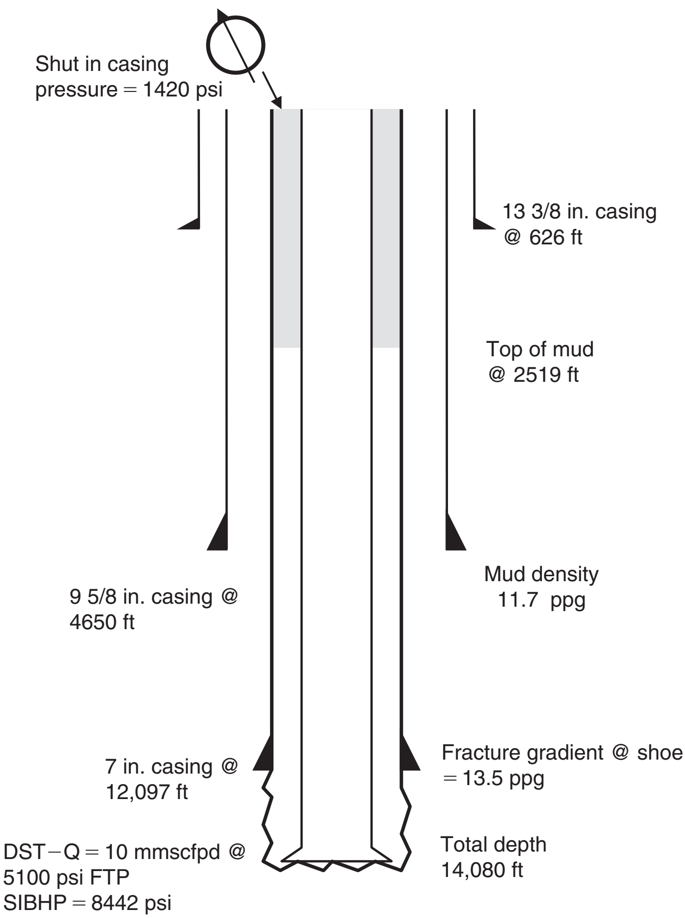

Fig. 5.5 Well in southeastern New Mexico after gas migrated to the surface.

Example 5.3

Given:

Fig. 5.5

Depth, $D = 14{,}080$ ft
Surface pressure, $P_a = 1420$ psi
Mud weight, $\rho = 11.7$ ppg
Fracture gradient at shoe, $F_g = 0.702$ psi/ft
Intermediate casing:
7-in. casing at $D_{shoe} = 12{,}097$ ft
29 lb/ft P-110 82 ft
26 lb/ft S-95 7800 ft
29 lb/ft P-110 4200 ft
Gas gravity, $S_g = 0.6$
Bottom-hole pressure, $P_b = 8442$ psi
Temperature, $T_s = 540°\text{R}$
Kill-mud weight, $\rho_1 = 12.8$ ppg
Compressibility factor, $z_s = 0.82$
Capacity of drill pipe annulus, $C_{dpca} = 0.0264$ bbl/ft
Drill-stem test at 13,913 ft
Volume rate of flow, $Q = 10$ mmscfpd at 5100 psi
Plugged drill pipe at 12,513 ft

Required:

Design a procedure to lubricate kill mud into and the gas influx out of the annulus.

Solution:

Determine the height of the gas bubble, h, as follows from Eqs. (2.7) and (3.5):

$$P_b = \rho_f h + \rho_m (D - h) + P_a$$

$$\rho_f = \frac{S_g P_g}{53.3 z_s T_s}$$

$$\rho_f = \frac{(0.6)(1420)}{53.3(0.82)(540)}$$

$$\rho_f = \mathbf{0.036\ psi/ft}$$

Solve for h using Eq. (2.7):

$$8442 = 1420 + (0.052)(11.7)(13913 - h) + 0.036h$$
$$h = \mathbf{2520\ ft}$$

Gas volume at the surface, V_s, is given as

$$V_2 = (2520)(0.0264)$$
$$V_s = \mathbf{66.5\ bbls}$$

Continued

Example 5.3—cont'd

Determine the margin for pressure increase at the casing shoe using Eq. (5.1):

$$P_{shoe} = \rho_f h + P_a + \rho_m (D_{shoe} - h) \tag{5.1}$$

where

P_{shoe} = pressure at the casing shoe, psi
ρ_f = influx gradient, psi/ft
h = height of the influx, ft
P_a = annulus pressure, psi
ρ_m = original mud gradient, psi/ft
D_{shoe} = depth to the casing shoe, ft

$$P_{shoe} = 0.036(2520) + 1420 + 0.6087(12{,}097 - 2520)$$
$$P_{shoe} = \mathbf{7340\ psi}$$

Determine maximum permissible pressure at shoe, P_{frac}:

$$\begin{aligned} P_{frac} &= F_g D_{shoe} \\ P_{frac} &= (0.052)(13.5)(12{,}097) \\ P_{frac} &= \mathbf{8492\ psi} \end{aligned} \tag{5.2}$$

where

F_g = fracture gradient, psi/ft
D_{shoe} = depth of the casing shoe, ft

Maximum increase in surface pressure and hydrostatic, ΔP_t, that will not result in fracturing at the shoe is given by Eq. (5.3):

$$\begin{aligned} \Delta P_t &= P_{frac} - P_{shoe} \\ \Delta P_t &= 8492 - 7340 \\ \Delta P_t &= \mathbf{1152\ psi} \end{aligned} \tag{5.3}$$

where

P_{frac} = fracture pressure at casing shoe, psi
P_{shoe} = calculated pressure at casing shoe, psi

The kill mud gradient will be 0.677 psi/ft. The volume of the kill-weight mud, V_1, with density, ρ_{m1}, to achieve ΔP_t is given by Eq. (5.4):

$$V_1 = X_1 - \left[X_1^2 - \frac{\Delta P_t C_{dpca} V_s}{\rho_{m1}} \right]^{\frac{1}{2}} \tag{5.4}$$

$$X_1 = \frac{\rho_{m1} V_s + C_{dpca}(P_a + \Delta P_t)}{2(\rho_{m1})} \tag{5.5}$$

$$X_1 = \frac{0.667(66.5) + 0.0264(1420 + 1152)}{2(0.667)}$$
$$X_1 = \mathbf{84.150}$$

Example 5.3—cont'd

$$V_1 = 84.150 - \left[84.150^2 - \frac{1152(0.0264)(66.5)}{0.667}\right]^{\frac{1}{2}}$$
$$V_1 = \mathbf{20.5\ bbls}$$

where
ΔP_t = maximum surface pressure increase, psi
C_{dpca} = annular capacity, bbl/ft
V_s = gas volume at the surface, bbl
ρ_{m1} = kill-mud gradient, psi/ft
X_1 = intermediate calculation

Determine the effect of pumping 20 bbl of kill mud with density $\rho_1 = 12.8$ ppg. The resulting additional hydrostatic, ΔHyd, is calculated with Eq. (5.6):

$$\Delta Hyd = 0.052\rho_1\left(\frac{V_1}{C_{dpca}}\right) \tag{5.6}$$

$$\Delta Hyd = (0.052)(12.8)\left(\frac{20}{0.0264}\right)$$
$$\Delta Hyd = \mathbf{504\ psi}$$

Additional surface pressure resulting from compressing the bubble at the surface with 20 bbl of kill mud is given by Eq. (2.3):

$$\frac{P_1 V_1}{z_1 T_1} = \frac{P_2 V_2}{z_2 T_2}$$

1 = prior to pumping kill mud
2 = after pumping kill mud
Therefore, by modifying Eq. (2.2),

$$P_2 = \frac{P_1 V_1}{V_2}$$
$$P_2 = \frac{(1420)(66.5)}{(66.5 - 20)}$$
$$P_2 = \mathbf{2031\ psi}$$

Additional surface pressure, ΔP_s, is given as

$$\Delta P_s = P_2 - P_a$$
$$\Delta P_s = 2031 - 1420 \tag{5.7}$$
$$\Delta P_s = \mathbf{611\ psi}$$

Total pressure increase, ΔP_{total}, is given as

$$\Delta P_{total} = \Delta \text{Hyd} + \Delta P_s$$
$$\Delta P_{total} = 504 + 611 \tag{5.8}$$
$$\Delta P_{total} = \mathbf{1115\ psi}$$

Continued

Example 5.3—cont'd

Since ΔP_{total} is less than the maximum permissible pressure increase, ΔP_t, calculated using Eq. (5.3), pump 20 bbl of 12.8 ppg mud at 1 bpm and shut in to permit the gas to migrate to the surface.

Observe initial P_2 after pumping = 1950 psi.

Observe 2 h shut-in P_2 = 2031 psi.

The surface pressure, P_a, may now be reduced by bleeding **ONLY GAS** from P_2 to

$$P_{newa} = P_a - \Delta Hyd$$
$$P_{newa} = 1420 - 504$$
$$P_{newa} = \mathbf{916\ psi}$$

However, the new surface pressure must be used to determine the effective hydrostatic pressure at 13,913 ft to ensure no additional influx.

Eq. (2.7) expands to Eq. (5.9):

$$P_b = P_a + \rho_f h + \rho_m (D - h - h_1) + \rho_{m1} h_1$$
$$h = \frac{V_s}{C_{dpca}} \tag{5.9}$$

where

V_s = remaining volume of influx, bbl

$$h = \frac{66.5 - 20}{0.0264}$$
$$h = \mathbf{1762\ ft}$$
$$h_1 = \frac{V_1}{C_{dpca}}$$
$$h_1 = \frac{20}{0.0264}$$
$$h_1 = \mathbf{758\ ft}$$
$$\rho_f = \frac{S_g P_s}{53.3 z_s T_s}$$
$$\rho_f = \frac{(0.6)(916)}{(53.3)(0.866)(540)}$$
$$\rho_f = \mathbf{0.022\ psi/ft}$$
$$P_b = 916 + (0.6084)(13{,}913 - 1762 - 758) + (0.022)(1762) + (0.667)(758)$$
$$P_b = \mathbf{8392\ psi}$$

However, the shut-in pressure is 8442 psi. Therefore, since the effective hydrostatic cannot be less than the reservoir pressure, the surface pressure can only be bled to

$$P_a = 916 + (8442 - 8392)$$
$$P_a = \mathbf{966\ psi}$$

Example 5.3—cont'd

***Important:* The pressure cannot be reduced by bleeding mud. If mud is bled from the annulus, the well must be shut in for a longer period to allow the gas to migrate to the surface.**

Now, the procedure must be repeated until the influx is lubricated from the annulus and replaced by mud:

$$\rho_f = \frac{S_g P_s}{53.3 z_s T_s}$$

$$\rho_f = \frac{(0.6)(966)}{53.3(0.866)(540)}$$

$$\rho_f = \mathbf{0.023\ psi/ft}$$

Now, solving for h, use

$$h = \frac{V_s}{C_{dpca}}$$

$$h = \mathbf{1762\ ft}$$

Similarly, solving for h_1,

$$h_1 = \frac{V_1}{C_{dpa}}$$

$$h_1 = \frac{20}{0.0264}$$

$$h_1 = \mathbf{758\ ft}$$

Determine the margin for pressure increase at the casing shoe using Eq. (5.10), which is Eq. (5.1) modified for inclusion of kill mud, ρ_1:

$$\begin{aligned} P_{shoe} &= \rho_f h + P_a + \rho_m (D_{shoe} - h - h_1) + \rho_1 h_1 \\ P_{shoe} &= 0.023(1762) + 966 + 0.6087 \\ &\quad \times (12{,}097 - 1762 - 758) + (0.052)(12.8)(758) \\ P_{shoe} &= \mathbf{7339\ psi} \end{aligned} \tag{5.10}$$

The maximum permissible pressure at shoe, P_{frac}, from Eq. (5.2) is equal to 8492 psi.

The maximum increase in surface pressure and hydrostatic, ΔP_t, that will not result in fracturing at the shoe is given by Eq. (5.3):

$$\Delta P_t = P_{frac} - P_{shoe}$$

$$\Delta P_t = 8492 - 7339$$

$$\Delta P_t = \mathbf{1153\ psi}$$

Continued

Example 5.3—cont'd

The volume of the kill-weight mud, V_1, with density, ρ_1, to achieve ΔP_t is given by Eqs. (5.4) and (5.5):

$$V_1 = X_1 - \left[X_1^2 - \frac{\Delta P_t C_{dpca} V_s}{\rho_{m_1}}\right]^{\frac{1}{2}}$$

$$X_1 = \frac{\rho_{m1} V_s + C_{dpca}(P_a - \Delta P_t)}{2(\rho_{m1})}$$

$$X_1 = \frac{0.667(46.5) + 0.0264(966 + 1153)}{2(0.667)}$$

$$X_1 = \mathbf{65.185}$$

$$V_1 = 65.185 - \left[65.185^2 - \frac{1153(0.0264)(46.5)}{0.667}\right]^{\frac{1}{2}}$$

$$V_1 = \mathbf{19.1\ bbls}$$

Determine the effect of pumping 19 bbl of kill mud with density $\rho_1 = 12.8$ ppg. The resulting additional hydrostatic, ΔHyd, is

$$\Delta Hyd = (0.052)(\rho_1)\left(\frac{V_1}{C_{dpca}}\right)$$

$$\Delta Hyd = (0.052)(12.8)\left(\frac{19}{0.0264}\right)$$

$$\Delta Hyd = \mathbf{480\ psi}$$

Additional surface pressure resulting from compressing the bubble at the surface with 19 bbl of kill mud is

$$P_2 = \frac{P_1 V_1}{V_2}$$

$$P_2 = \frac{(966)(46.5)}{(46.5 - 19)}$$

$$P_2 = \mathbf{1633\ psi}$$

Additional surface pressure, ΔP_s, is given as

$$\Delta P_s = P_2 - P_a$$

$$\Delta P_s = 1633 - 966$$

$$\Delta P_s = \mathbf{677\ psi}$$

Total pressure increase, ΔP_{total}, is given by Eq. (5.8):

Example 5.3—cont'd

$$\Delta P_{total} = \Delta Hyd + \Delta P_s$$
$$\Delta P_{total} = 480 + 667$$
$$\Delta P_{total} = \mathbf{1147\ psi}$$

Since ΔP_{total} is less than the maximum permissible pressure increase, ΔP_t, calculated using Eq. (5.3), pump 19 bbl of 12.8 ppg mud at 1 bpm and shut in to permit the gas to migrate to the surface.

Observe initial P_2 after pumping = 1550 psi.

Observe 2 h shut-in $P_2 = 1633$ psi.

The surface pressure, P_a, may now be reduced by bleeding **ONLY GAS** from P_2 to

$$P_{newa} = P_a - \Delta Hyd$$
$$P_{newa} = 966 - 480$$
$$P_{newa} = \mathbf{486\ psi}$$

However, the new surface pressure must be used to determine the effective hydrostatic pressure at 13,913 ft to ensure no additional influx.

The bottom-hole pressure is given by Eq. (5.9):

$$P_b = P_a + \rho_f h + \rho_m (D - h - h_1) + \rho_{m1} h_1$$

$$h = \frac{V_s}{C_{dpca}}$$
$$h = \frac{46.5 - 19}{0.0264}$$
$$h = \mathbf{1042\ ft}$$

$$h_1 = \frac{V_1}{C_{dpca}}$$
$$h_1 = \frac{39}{0.0264}$$
$$h_1 = \mathbf{1477\ ft}$$

$$\rho_f = \frac{S_g P_s}{53.3 z_s T_s}$$
$$\rho_f = \frac{(0.6)(486)}{(53.3)(0.930)(540)}$$
$$\rho_f = \mathbf{0.011\ psi/ft}$$

$$P_b = 486 + (0.6084)(13{,}913 - 1042 - 1477) + (0.011)(1042) + (0.667)(1477)$$
$$P_b = \mathbf{8415\ psi}$$

Continued

Example 5.3—cont'd

However, the shut-in pressure is 8442 psi. Therefore, since the effective hydrostatic cannot be less than the reservoir pressure, the surface pressure can only be bled to

$$P_a = 486 + (8442 - 8415)$$
$$P_a = \mathbf{513\ psi}$$

The surface pressure must be bled to only 513 psi to ensure no additional influx by bleeding only dry gas through the choke manifold. *Important:* No mud can be bled from the annulus. If the well begins to flow mud from the annulus, it must be shut in until the gas and mud separate.

Again, the procedure must be repeated:

$$\rho_f = \frac{S_g P_s}{53.3\, z_s T_s}$$
$$\rho_f = \frac{(0.6)(513)}{53.3(0.926)(540)}$$
$$\rho_f = \mathbf{0.012\ psi/ft}$$

Now, solving for h, use

$$h = \frac{V_s}{C_{dpca}}$$
$$h = \frac{46.5 - 19.0}{0.0264}$$
$$h = \mathbf{1042\ ft}$$

Similarly, solving for h_1:

$$h_1 = \frac{V_1}{C_{dpca}}$$
$$h_1 = \frac{39}{0.0264}$$
$$h_1 = \mathbf{1477\ ft}$$

Determine the margin for pressure increase at the casing shoe using Eq. (5.10):

$$P_{shoe} = \rho_f h + P_a + \rho_m (D_{shoe} - h - h_1) + \rho_1 h_1$$
$$P_{shoe} = 0.012(1042) + 513 + 0.6084 \times (12{,}097 - 1042 - 1477) + (0.052)(12.8)(1477)$$
$$P_{shoe} = \mathbf{7336\ psi}$$

Example 5.3—cont'd

The maximum permissible pressure at shoe, P_{frac}, from Eq. (5.2) is equal to 8492 psi.

The maximum increase in surface pressure and hydrostatic, ΔP_t, that will not result in fracturing at the shoe is given by Eq. (5.3):

$$\Delta P_t = P_{frac} - P_{shoe}$$
$$\Delta P_t = 8492 - 7336$$
$$\Delta P_t = \mathbf{1156\ psi}$$

The volume of the kill-weight mud, V_1, with density, ρ_1, to achieve ΔP_t is given by Eqs. (5.4) and (5.5):

$$V_1 = X_1 \left[X_1^2 - \frac{\Delta P_t C_{dpca} V_s}{\rho_{m1}} \right]^{\frac{1}{2}}$$
$$X_1 = \frac{\rho_{m1} V_s + C_{dpca}(P_a - \Delta P_t)}{2(\rho_{m1})}$$
$$X_1 = \frac{0.667(27.5) + (0.0264)(513 + 1156)}{2(0.667)}$$
$$X_1 = \mathbf{46.780}$$

$$V_1 = 46.780 - \left[46.780^2 - \frac{1156(0.0264)(27.5)}{0.667} \right]^{\frac{1}{2}}$$
$$V_1 = \mathbf{16.3\ bbls}$$

Determine the effect of pumping 16 bbl of kill mud with density $\rho_1 = 12.8$ ppg. The resulting additional hydrostatic, ΔHyd, is given by Eq. (5.6):

$$\Delta Hyd = 0.052 \rho_1 \left(\frac{V_1}{C_{dpca}} \right)$$
$$\Delta Hyd = (0.052)(12.8) \left(\frac{16}{0.0264} \right)$$
$$\Delta Hyd = \mathbf{404\ psi}$$

Additional surface pressure resulting from compressing the bubble at the surface with 16 bbl of kill mud is

$$P_2 = \frac{P_1 V_1}{V_2}$$
$$P_2 = \frac{(513)(27.5)}{(27.5 - 16)}$$
$$P_2 = \mathbf{1227\ psi}$$

Continued

Example 5.3—cont'd

Additional surface pressure, ΔP_s is given by Eq. (5.7):

$$\Delta P_s = P_2 - P_a$$
$$\Delta P_s = 1227 - 513$$
$$\Delta P_s = \mathbf{714\,psi}$$

Total pressure increase, ΔP_{total}, is given by Eq. (5.8):

$$\Delta P_{total} = \Delta Hyd + \Delta P_s$$
$$\Delta P_{total} = 404 + 714$$
$$\Delta P_{total} = \mathbf{118\,psi}$$

Since ΔP_{total} is less than the maximum permissible pressure increase, ΔP_t, calculated using Eq. (5.3), pump 16 bbl of 12.8 ppg mud at 1 bpm and shut in to permit the gas to migrate to the surface.

In 2–4 h shut-in $P_2 = 1227$ psi.

The surface pressure, P_a, may now be reduced by bleeding **ONLY GAS** from P_2 to

$$P_{newa} = P_a - \Delta Hyd$$
$$P_{newa} = 513 - 404$$
$$P_{newa} = \mathbf{109\,psi}$$

However, the new surface pressure must be used to determine the effective hydrostatic pressure at 13,913 ft to insure no additional influx.

Pursuant to Eq. (5.9),

$$P_b = P_a + \rho_f h + \rho_m (D - h - h_1) + \rho_{m1} h_1$$

$$h = \frac{V_s}{C_{dpca}}$$
$$h = \frac{27.5 - 16}{0.0264}$$
$$h = \mathbf{436\,ft}$$

$$h_1 = \frac{V_1}{C_{dpca}}$$
$$h_1 = \frac{55}{0.0264}$$
$$h_1 = \mathbf{2083\,ft}$$

$$\rho_f = \frac{S_g P_s}{53.3 z_s T_s}$$
$$\rho_f = \frac{(0.6)(109)}{(53.3)(0.984)(540)}$$
$$\rho_f = \mathbf{0.0023\,psi/ft}$$

Example 5.3—cont'd

$$P_b = 109 + (0.6084)(13{,}913 - 436 - 2083) + (0.011)(436) + (0.667)(2083)$$
$$P_b = \mathbf{8431\ psi}$$

However, the shut-in pressure is 8442 psi. Therefore, since the effective hydrostatic cannot be less than the reservoir pressure, the surface pressure can only be bled to

$$P_a = 109 + (8442 - 8431)$$
$$P_a = \mathbf{120\ psi}$$

The surface pressure must be bled to only 120 psi to ensure no additional influx by bleeding only dry gas through the choke manifold. *Important:* No mud can be bled from the annulus. If the well begins to flow mud from the annulus, it must be shut in until the gas and mud separate.

Now, the procedure is repeated for the final increment:

$$\rho_f = \frac{S_g P_s}{53.3 z_s T_s}$$

$$\rho_f = \frac{(0.6)(120)}{53.3(0.983)(540)}$$

$$\rho_f = \mathbf{0.0025\ psi/ft}$$

Now, solving for h, use

$$h = \frac{V_s}{C_{dpca}}$$

$$h = \frac{27.5 - 16.0}{0.0264}$$

$$h = \mathbf{436\ ft}$$

Similarly, solving for h_1,

$$h_1 = \frac{V_1}{C_{dpca}}$$

$$h_1 = \frac{55}{0.0264}$$

$$h_1 = \mathbf{2083\ ft}$$

Determine the margin for pressure increase at the casing shoe using Eq. (5.10):

Continued

Example 5.3—cont'd

$$P_{shoe} = \rho_f h + P_a + \rho_m (D_{shoe} - h - h_1) + \rho_1 h_1$$
$$P_{shoe} = 0.0025(436) + 120 + 0.6084 \times (12{,}097 - 436 - 2083) + (0.052)(12.8)(2083)$$
$$P_{shoe} = \mathbf{7338\ psi}$$

The maximum permissible pressure at shoe, P_{frac}, from Eq. (5.2) is equal to 8489 psi.

The maximum increase in surface pressure and hydrostatic, ΔP_t, that will not result in fracturing at the shoe is given by Eq. (5.3):

$$\Delta P_t = P_{frac} - P_{shoe}$$
$$\Delta P_t = 8492 - 7338$$
$$\Delta P_t = \mathbf{1154\ psi}$$

The volume of the kill-weight mud, V_1, with density, ρ_1, to achieve ΔP_t is given by Eqs. (5.4) and (5.5):

$$V_1 = X_1 - \left[X_1^2 - \frac{\Delta P_t C_{dpca} V_s}{\rho m1}\right]^{\frac{1}{2}}$$
$$X_1 = \frac{\rho m1\, V_s + C_{dpca}(P_a - \Delta P_t)}{\rho m1}$$
$$X_1 = \frac{0.667(11.5) + 0.0264(120 + 1154)}{2(0.667)}$$
$$X_1 = \mathbf{30.963}$$

$$V_1 = 30.963 - \left[30.963^2 - \frac{1154(0.0264)(11.5)}{0.667}\right]^{\frac{1}{2}}$$
$$V_1 = \mathbf{10.14\ bbls}$$

Determine the effect of pumping 10 bbl of kill mud with density $\rho_1 = 12.8$ ppg. The resulting additional hydrostatic, ΔHyd, is given by Eq. (5.6):

$$\Delta Hyd = 0.052\rho 1\left(\frac{V_1}{C_{dpca}}\right)$$
$$\Delta Hyd = (0.052)(12.8)\left(\frac{10}{0.0264}\right)$$
$$\Delta Hyd = \mathbf{252\ psi}$$

Additional surface pressure resulting from compressing the bubble at the surface with 10 bbl of kill mud is

Example 5.3—cont'd

$$P_2 = \frac{P_1 V_1}{V_2}$$

$$P_2 = \frac{(120)(11.5)}{(11.5-10)}$$

$$P_2 = \mathbf{920\ psi}$$

Additional surface pressure, ΔP_s, is given as

$$\Delta P_s = P_2 - P_a$$
$$\Delta P_s = 920 - 120$$
$$\Delta P_s = \mathbf{800\ psi}$$

Total pressure increase, ΔP_{total}, is given as

$$\Delta P_{total} = \Delta Hyd + \Delta P_s$$
$$\Delta P_{total} = 252 + 800$$
$$\Delta P_{total} = \mathbf{1052\ psi}$$

Since ΔP_{total} is less than the maximum permissible pressure increase, ΔP_t, calculated using Eq. (5.3), pump 10 bbl of 12.8-ppg mud at 1 bpm and shut in to permit the gas to migrate to the surface.

In 2–4 h shut-in $P_2 = 920$ psi.

The surface pressure, P_a, may now be reduced by bleeding **ONLY GAS** from P_2 to

$$P_{newa} = P_a - \Delta Hyd$$
$$P_{newa} = 120 - 252$$
$$P_{newa} = \mathbf{0\ psi}$$

and the hole filled and observed.

The well is killed.

SUMMARY

	Volume pumped	Old surface pressure	Surface pressure after adding kill mud	Surface pressure after bleeding
Initial Conditions	-0-	1420		
First stage	20	1420	2031	966
Second stage	19	966	1633	513
Third stage	16	513	1227	120
Fourth stage	10	120	920	-0-

By following this schedule, the well can be killed safely without violating the casing seat and losing more mud and without permitting any additional influx of formation gas into the wellbore.

In summary, the well is controlled by pumping kill-weight mud into the annulus and bleeding dry gas out of the annulus. The volume of kill fluid that can be pumped without fracturing the casing seat is determined from Eq. (5.3). Logically, the surface pressure should be reduced from the value prior to lubricating kill mud by the additional hydrostatic contributed by the kill-weight mud. However, for obvious reasons, the effective hydrostatic cannot be less than the reservoir pressure. At the lower surface pressures, the gas hydrostatic gradient is less, and the final surface pressure must be higher to reflect the difference in gas gradient and prevent additional influx. The analysis is continued until the well is dead. Rudimentary analysis suggests higher mud weights for well control.

DYNAMIC KILL OPERATIONS

Simply put, to kill a well dynamically is to use frictional pressure losses to control the flowing bottom-hole pressure and, ultimately, the static bottom-hole pressure of the blowout.

Dynamic kill implies the use of a kill fluid whose density results in a hydrostatic column that is less than the static reservoir pressure. Therefore, the frictional pressure loss of the kill fluid is required to stop the flow of reservoir fluids. Dynamic kill in the purest sense was intended as an intermediate step in the well control procedure. Procedurally, after the blowout was dynamically controlled with a fluid of lesser density, it was ultimately controlled with a fluid of greater density, which resulted in a hydrostatic greater than the reservoir pressure.

Generically and in this text, dynamic kill includes control procedures utilizing fluids with densities less than and much greater than that required to balance the static reservoir pressure. In reality, when the density of the kill fluid is equal to or greater than that required to balance the static reservoir pressure, the fluid dynamics are more properly described as a multiphase kill procedure.

Dynamically controlling a well using a multiphase kill procedure is one of the oldest and most widely used fluid control operations. In the past, it has been a "seat-of-the-pants" operation with little or no technical evaluation. Most of the time, well control specialists had some arbitrary rules of thumb;

for example, the kill fluid had to be 2 lbs/gal heavier than the mud used to drill the zone, or the kill fluid had to achieve some particular annular velocity. Usually, that translated into manifolding together all the pumps in captivity, weighting the mud up as high as possible, pumping like hell, and hoping for the best. Sometimes, it worked, and sometimes, it did not.

There are many applications of the dynamic and multiphase kill procedures, and any well control operation should be studied from that perspective. The most common application is when the well is flowing out of control and the drill pipe is on bottom. The kill fluid is pumped to the bottom of the hole through the drill pipe, and the additional hydrostatic of the kill fluid along with the increased friction pressure resulting from the kill fluid controls the well.

Multiphase kill operations were routine in the Arkoma Basin in the early 1960s. There, air drilling was popular. In air drilling operations, every productive well is a blowout. Under different circumstances, some of them would have made the front page of the *New York Times*. At one location just east of McCurtain, Oklahoma, the fire was coming out of an 8 in. blooey line and was almost as high as the crown of the 141 ft derrick. The blooey line was 300 ft long, and you could toast marshmallows on the rig floor. The usual procedure was the seat-of-the-pants multiphase kill, and it killed the well.

The most definitive work on the pure dynamic kill was done by Mobil Oil Corporation and reported by Elmo Blount and Edy Soeiinah [2]. The biggest gas field in the world is Mobil's Arun Field in North Sumatra, Indonesia. On 4 June 1978, Well No. C-II-2 blew out while drilling and caught fire. The rig was immediately consumed. The well burned for 89 days at an approximate rate of 400 million standard cubic feet per day.

Due to the well's high deliverability and potential, it was expected to be extremely difficult to kill. The engineering was so precise that only one relief well was required. That a blowout of this magnitude was completely dead 1 h and 50 min after pumping operations commenced is a tribute to all involved. One of the most significant contributions resulting from this job was the insight into the fluid dynamics of a dynamic kill.

The engineering concepts of a dynamic kill are best understood by considering the familiar U-tube of Fig. 5.6. The left side of the U-tube may represent a relief well and the right side a blowout, as in the case just discussed, or the left side may represent the drill pipe, while the right side would correspond to the annulus, as is the case in many well control situations. The connecting interval may be the formation in the case of a relief well with the valve representing the resistance due to the flow of fluids through the

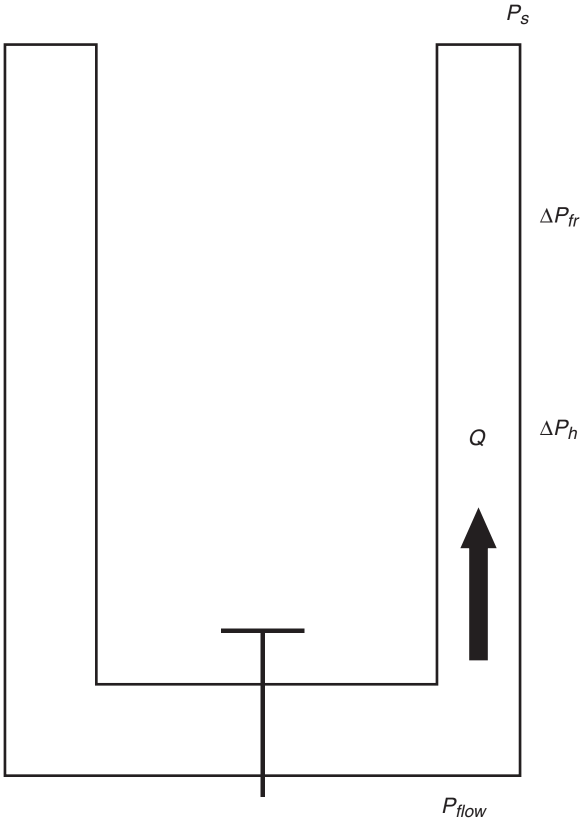

Fig. 5.6 Dynamic kill schematic.

formation. In the case of the drill pipe-annulus scenario, the valve may represent the friction in the drill string or the nozzles in the bit, or the situation may be completely different. Whatever the situation, the technical concepts are basically the same.

The formation is represented as flowing up the right side of the U-tube with a flowing bottom-hole pressure, P_{flow}, which is given by the following equation:

$$P_{flow} = P_a + \Delta P_{fr} + \Delta P_h \tag{5.11}$$

where

P_a = surface pressure, psi
ΔP_{fr} = frictional pressure, psi
ΔP_h = hydrostatic pressure, psi

Fig. 5.7 Typical open flow potential curve.

The capability of the formation to deliver hydrocarbons to the wellbore is governed by the familiar back-pressure curve illustrated in Fig. 5.7 and described by the Eq. (5.12):

$$Q = C\left(P_b^2 - P_{flow}^2\right)^n \tag{5.12}$$

where

Q = flow rate, mmscfpd
P_b = formation pore pressure, psi
P_{flow} = flowing bottom-hole pressure, psi
C = constant
n = slope of back-pressure curve
n = 0.5 for turbulence
n = 1.0 for laminar flow

Finally, the reaction of the formation to an increase in flowing bottom-hole pressure, P_{flow}, is depicted by the classic Horner plot, illustrated in Fig. 5.8. The problem is to model the blowout considering these variables.

In the past, shortcuts have been taken for the sake of simplicity. For example, the simplest approach is to design a kill fluid and rate such that the frictional pressure loss plus the hydrostatic is greater than the shut-in bottom-hole pressure, P_b. This rate would be sufficient to maintain control. Eqs. (4.13) and (4.14) for frictional pressure losses in turbulent flow can be used in such an analysis.

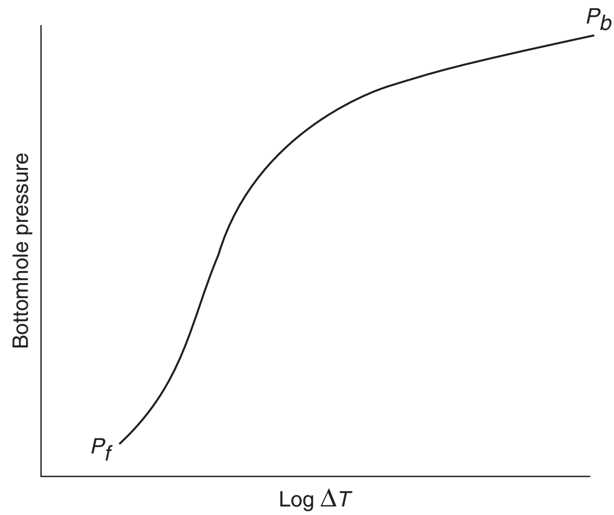

Fig. 5.8 Typical pressure-buildup curve.

Consider the Example 5.4:

Example 5.4

Given:

Depth, $D = 10{,}000$ ft

Kill fluid, $\rho_1 = 8.33$ ppg

Kill-fluid gradient, $\rho_{m1} = 0.433$ psi/ft

Bottom-hole pressure, $P_b = 5200$ psi

Inside diameter of pipe, $D_i = 4.408$ in.

Surface pressure, $P_a =$ atmospheric

Fig. 5.6

Required:

Determine the rate required to kill the well dynamically with water.

Solution:

$$P_{flow} = P_a + \Delta P_{fr} + \Delta P_h$$

$$\Delta P_h = 0.433(10,000)$$

$$\Delta P_h = \mathbf{4330\,psi}$$

$$\Delta P_{fr} = 5200 - 4330$$

$$\Delta P_{fr} = \mathbf{870\,psi}$$

Rearranging Eq. (4.14) where $\Delta P_{fr} = P_{fti}$,

Example 5.4—cont'd

$$Q = \left[\frac{P_{fti} D_i^{4.8}}{7.7(10^{-5})\rho_1^{.8} PV^{.2} l}\right]^{\frac{1}{1.8}}$$

$$Q = \left[\frac{(870)(4.408)^{4.8}}{7.7(10^{-5})(8.33)^{.8}(1)^{.2}(10,000)}\right]^{\frac{1}{1.8}}$$

$$Q = \mathbf{1011\ gpm}$$

$$Q = \mathbf{24.1\ bpm}$$

Therefore, as illustrated in Example 5.4, the well would be dynamically controlled by pumping fresh water through the pipe at 24 bpm. The dynamic kill procedure would be complete when the water was followed with kill mud of sufficient density (10 ppg in this example) to control the bottom-hole pressure.

The rate required to maintain control is insufficient in most instances to achieve control and is considered to be the minimum rate for a dynamic kill operation. Kouba, et al. have suggested that the rate sufficient to maintain control is the minimum and that the maximum rate is approximated by Eq. (5.13) [3]:

$$Q_{k\max} = A\left(\frac{2g_c D_{tvd} D_h}{f D_{md}}\right)^{\frac{1}{2}} \tag{5.13}$$

where

g_c = gravitational constant, $\frac{\mathrm{lb}_m \cdot \mathrm{ft}}{\mathrm{lb}_f \cdot s^2}$

A = cross-sectional area, ft^2

D_h = hydraulic diameter, ft

D_{tvd} = vertical well height, ft

D_{md} = measured well length, ft

f = moody friction factor, dimensionless

Consider Example 5.5:

Example 5.5

Given:

Same conditions as Example 5.4

Required:

Calculate the maximum kill rate using Eq. (5.13).

Continued

Example 5.5—cont'd
Solution:
Solving Eq. (5.13) gives

$$Q_{k\max} = A\left(\frac{2g_c D_{tvd} D_h}{f\, D_{md}}\right)^{\frac{1}{2}}$$

$$Q_{k\max} = 0.106\left(\frac{2(32.2)(10,000)(0.3673)}{0.019(10,000)}\right)^{\frac{1}{2}}$$

$$Q_{k\max} = \mathbf{3.74}\frac{\text{ft}^3}{s}$$

$$Q_{k\max} = \mathbf{40\ bpm}$$

As illustrated in Examples 5.4 and 5.5, the minimum kill rate is 24 bpm, and the maximum kill rate is 40 bpm. The rate required to kill the well is somewhere between these values and is very difficult to determine. Multiphase flow analysis is required.

The methods of multiphase flow analysis are very complex and based upon empirical correlations obtained from laboratory research. The available correlations and research are based upon gas-lift models describing the flow of gas, oil, and water inside small pipes. Precious little research has been done to describe annular flow, much less the multiphase relationship between gas, oil, drilling mud, and water flowing up a very large, inclined annulus. The conditions and boundaries describing most blowouts are very complex to be described by currently available multiphase models.

It is beyond the scope of this work to offer an in-depth discussion of multiphase flow calculations. However, consider this example from the real world. A few years ago in Taiwan, the CHK 140 blew out due to CO_2 corrosion. Both the tubing strings and all the casing strings were communicated. The well control company tried running a packer with the intention of setting it below the holes and killing the well. The flow set the packer in the casing in the midst of the holes. Their plan B was to run tubing through the bore of the packer, which was 20 ft in length, and pump heavy mud to kill the well. The well control company presented a kill plan based on extensive computer analyses complete with the required pump rate and mud density to kill the well. The attempt failed miserably, and heavy mud broached to the surface all over the location.

The well control company blamed their failure on erroneous input from the operator. Their extensive report, which was based on the pump rate, pump pressure data obtained during the failed kill attempt, concluded by saying that the well was not producing roughly 28 mmscfpd as they were told by the operator but was in reality producing in excess of 60 mmscfpd. And, they concluded, based on their analysis of the data, there was a tubing connection in the bore of the packer.

The operator asked me for my opinion. The well was only a couple of years old, and the original production tests were conclusive that the actual open flow potential was roughly 24 mmscfpd. I explained the shortcomings of multiphase calculations and that these calculations were never intended to be definitive in determining flow volumes. I further explained that it was nonsense to suggest that any multiphase flow calculations were so accurate that a small/short change kill geometry such as that represented by a tubing connection inside a 20 ft packer bore could be determined.

I further reminded the operator that measuring the flow from a well was simple. Since the well was wide open at the surface through vent lines, all that had to be done was to build an orifice meter loop. The orifice meter loop was built, and the volume rate of flow was determined to be roughly the same as the 24 mmscfpd determined by the production tests.

I would further suggest that the reader simply refers to the typical Moody friction factor diagram. The frictional pressure loss is a function of the diameter, fluid density, fluid velocity, length of the system, and friction factor. And, the friction factor is a function of the diameter of the flow system, the fluid density, the fluid viscosity, and the relative roughness "e" of the flow system. In an open hole, the diameter can change every inch, the relative roughness can change over every inch, the viscosity of the flow is unknown, and the density of the combined flow is anyone's guess considering that the flow stream might be a combination of oil, gas, water, mud, and solids. For further discussion of this topic, see Chapter 7—How to Drill a Relief Well.

Further complicating the problem is the fact that, in most instances, the productive interval does not react instantaneously as would be implied by the strict interpretation of Fig. 5.7. Actual reservoir response is illustrated by the classical Horner plot illustrated in Fig. 5.8. As illustrated in Fig. 5.8, the response by the reservoir to the introduction of a kill fluid is nonlinear.

For example, the multiphase frictional pressure loss (represented by Fig. 5.8) initially required to control the well is not frictional pressure loss that will control the static reservoir pressure. The multiphase frictional pressure loss required to control the well is that which will control the flowing bottom-hole pressure. The flowing bottom-hole pressure may be much less than the static bottom-hole pressure.

Further, several minutes to several hours may be required for the reservoir to stabilize at the reservoir pressure. Unfortunately, much of the data needed to understand the productive capabilities of the reservoir in a particular wellbore are not available until after the blowout is controlled. However, data from similar offset wells can be considered.

Consider the well control operation at the Williford Energy Company Rainwater No. 2–14 in Pope County near Russellville, Arkansas [4]. The wellbore schematic is presented as Fig. 5.9. A high-volume gas zone had been penetrated at 4620 ft. On the trip out of the hole, the well kicked.

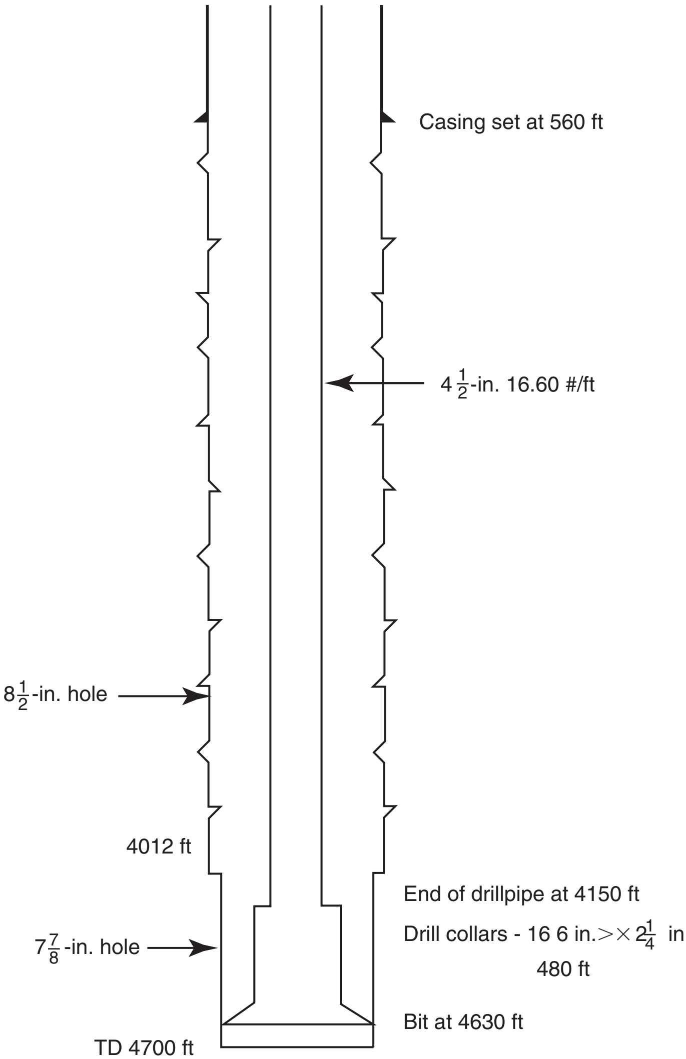

Fig. 5.9 Williford Energy Company, Rainwater No. 1, Pope County, Arkansas.

Mechanical problems prevented the well from being shut in, and it was soon flowing in excess of 20 mmscfpd through the rotary table. The drill pipe was stripped to bottom, and the well was diverted through the choke manifold. By pitot tube, the well was determined to be flowing at a rate of 34.9 mmscfpd with a manifold pressure of 150 psig. The wellbore schematic, open flow potential test, and Horner plot are presented as Figs. 5.9, 5.10, and 5.11, respectively.

In this instance, the Orkiszewski method was modified and utilized to predict the multiphase behavior [5]. The well was successfully controlled.

The technique used in the Williford Energy example is very conservative in that it determines the multiphase kill rate required to control the shut-in bottom-hole pressure of 1995 psi. Analysis of Fig. 5.11 indicates that the static bottom-hole pressure will not be reached in the blowout for more than 100 h. The flowing bottom-hole pressure when the kill procedure begins is only 434 psi and is only 1500 psi approximately 20 min after the flowing bottom-hole pressure has been exceeded. Of course, in this case, the kill operation is finished in just over 10 min. Including all these variables is more complex but well within the capabilities of modern computing technology. Based on this more complex analysis, the kill rate using 10.7 ppg mud was determined to be 10 bpm.

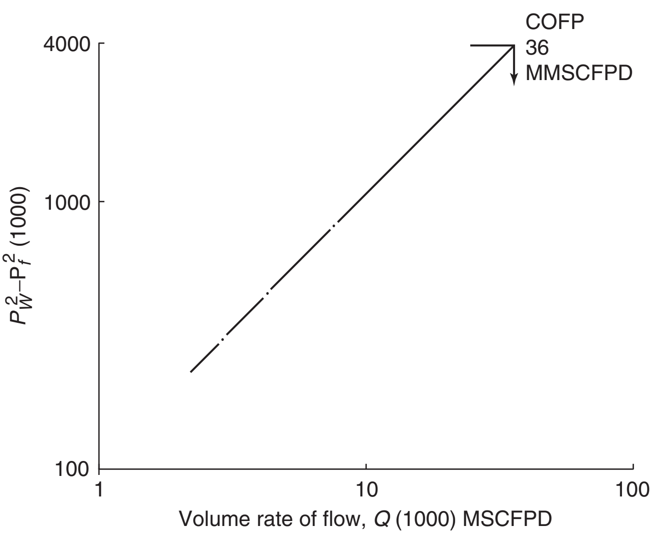

Fig. 5.10 Calculated open flow potential test, Williford Energy Company—Rainwater No. 2–14.

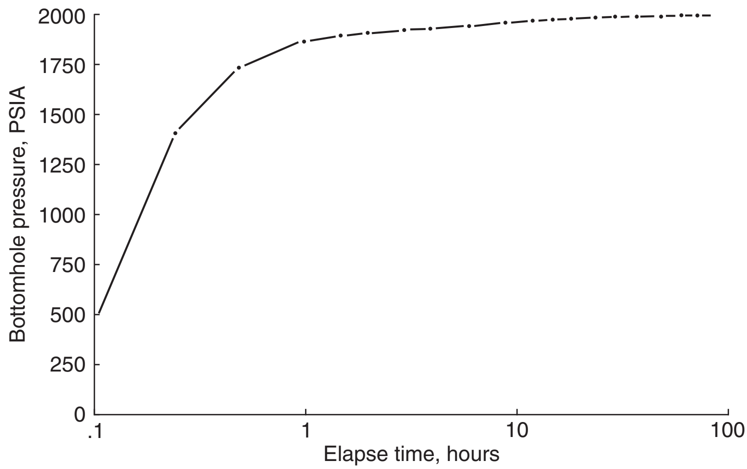

Fig. 5.11 Bottom-hole pressure-buildup test, Williford Energy Company—Rainwater No. 2–14.

The model is further complicated by the fact that the calculated open flow potential curve (COFP) presented as Fig. 5.10 is a very optimistic evaluation of sustained productive capacity. An actual open flow potential curve (AOFP) based on sustained production would be more appropriate for modeling actual kill requirements. A kill procedure based on the COFP is the more conservative approach. An AOFP curve more accurately reflects the effect of the pressure draw down in the reservoir in the vicinity of the wellbore.

THE MOMENTUM KILL

The momentum kill is a procedure where two fluids collide and the one with the greater momentum wins. If the greater momentum belongs to the fluid from the blowout, the blowout continues. If the greater momentum belongs to the kill fluid, the well is controlled. The technology of the momentum kill procedure is the newest and least understood of well control procedures. However, the technique itself is not new. In the late 1950s and early 1960s, the air drillers of eastern Oklahoma thought nothing of pulling into the surface pipe to mud up an air-drilled hole in an effort to avoid the hazards associated with the introduction of mud to the Atoka Shale.

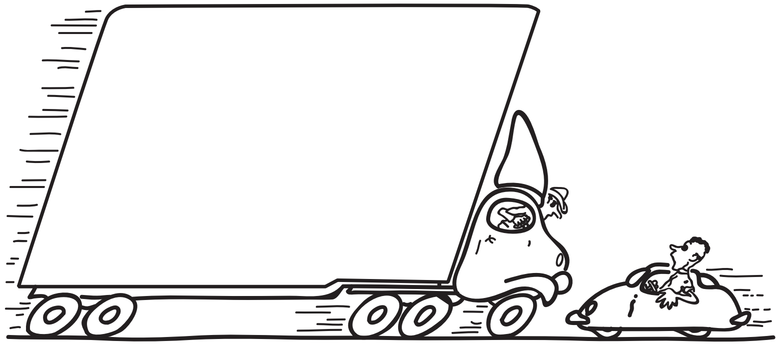

Fig. 5.12 Momentum kill concept with mass.

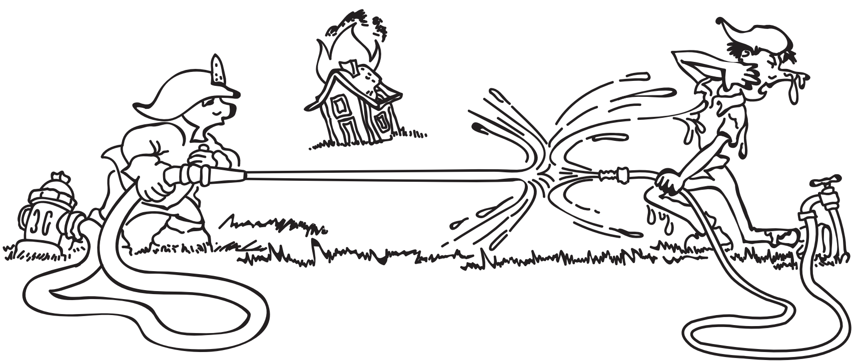

Fig. 5.13 Momentum kill concept with fluid.

Momentum kill concepts are best illustrated by Figs. 5.12 and 5.13. Fig. 5.12 illustrates a situation in which the outcome would never be in doubt. The most fundamental reasoning would suggest that the occupant of the car is in greater peril than the occupant of the truck. It is most likely that the momentum of the truck will prevail and the direction of the car will be reversed. Conceptually, fluid dynamics are not as easy. However, consider the men in Fig. 5.13. They have forgotten the fire and turned their attention to each other. Obviously, the one with the least momentum is destined for a bath.

The dynamics of a blowout are very much the same as those illustrated in Fig. 5.13. The fluid flowing from the blowout exhibits a definable quantity of momentum. Therefore, if the kill fluid is introduced at a greater momentum, the flow from the blowout is reversed when the fluids collide. The governing physical principles are not significantly different from those governing the collision of two trains, two cars, or two men. The mass with the greatest momentum will win the encounter.

Newton's second law states that the net force acting on a given mass is proportional to the time rate of change of linear momentum of that mass. In other words, the net external force acting on the fluid within a prescribed control volume equals the time rate of change of momentum of the fluid within the control volume plus the net rate of momentum transport out of the surfaces of the control volume.

Consider the following development with all units being basic:

Momentum is given as

$$M = \frac{mv}{g_c} \tag{5.14}$$

and the mass rate of flow is given as

$$\omega = \rho v A = \rho q \tag{5.15}$$

and, from the conservation of mass,

$$\rho v A = \rho_i v_i A_i \tag{5.16}$$

where

m = mass, lb_m

v = velocity, $\frac{ft}{s}$

g_c = gravitational constant, $\frac{lb_m \cdot ft}{lb_f \cdot s^2}$

ρ = density, $\frac{lb_m}{ft^3}$

q = volume rate of flow, $\frac{ft^3}{s}$

ω = mass rate of flow, $\frac{lb_m}{s}$

i = conditions at any point

A = cross-sectional flow area, ft^2

All variables are at standard conditions unless noted with a subscript, i.

The momentum of the kill fluid is easy to compute because it is essentially an incompressible liquid. The momentum of the kill fluid is given by Eq. (5.14):

$$M = \frac{mv}{g_c}$$

Substituting

$$v = \frac{q}{A}$$
$$m = \omega = \rho q$$

results in the momentum of the kill fluid, Eq. (5.17):

$$M = \frac{\rho q^2}{g_c A} \tag{5.17}$$

Since the formation fluids are compressible or partially so, the momentum is more difficult to determine. Consider the following development of an expression for the momentum of a compressible fluid.

From the conservation of mass, Eq. (5.16) is

$$\rho v A = \rho_i v_i A_i$$

And, for a gas, the mass rate of flow from Eq. (5.15) is

$$\omega = \rho v A = \rho q$$

Substituting into the momentum equation gives the momentum of the gas as

$$M = \frac{\rho q v_i}{g_c}$$

Rearranging the equation for the conservation of mass gives an expression for the velocity of the gas, v_i, at any location as follows:

$$v_i = \frac{q_i}{A}$$

$$v_i = \frac{\rho q}{\rho_i A}$$

From the ideal gas law, an expression for ρ_i, the density of the gas at any point in the flow stream, is given by Eq. (5.18):

$$\rho_i = \frac{S_g M_a P_i}{z_i T_i R} \tag{5.18}$$

where

S_g = specific gravity of the gas
M_a = molecular weight of air
P_i = pressure at point i, $\frac{\text{lb}_f}{\text{ft}^2}$
z_i = compressibility factor at point i

T_i = temperature at point i, °R

R = units conversion constant

Substituting results in an expression for v_i, the velocity of the gas at point i is as follows:

$$v_i = \frac{\rho q z_i T_i R}{S_g M_a P_i A} \tag{5.19}$$

Making the final substitution gives the final expression for the momentum of the gas:

$$M = \frac{(\rho q)^2 z_i T_i R}{S_g M_a P_i g_c A} \tag{5.20}$$

In this development, all units are BASIC! That means that these equations can be used in any system as long as the variables are entered in their basic units. In the English system, the units would be pounds, feet, and seconds. In the metric system, the units would be grams, centimeters, and seconds. Of course, the units' conversion constants would have to be changed accordingly.

Consider the example at the Pioneer Production Company Martin No. 1-7:

Example 5.6

Given:

Fig. 5.14

Bottom pressure, P_b = 5000 psi
Volume rate of flow, q = 10 mmscfpd
Specific gravity, S_g = 0.60
Flowing surface pressure, P_a = 14.65 psia
Kill-mud density, ρ_1 = 15 ppg
Tubing OD = $2\frac{3}{8}$ in.
Tubing ID = 1.995 in.
Casing ID = 4.892 in.
Temperature at 4000 ft, T_i = 580° R
Flowing pressure at 4000 ft, P_i = 317.6 psia
Compressibility factor at 4000 ft, z_i = 1.00

Required:

Determine the momentum of the gas at 4000 ft and the rate at which the kill mud will have to be pumped in order for the momentum of the kill mud to exceed the momentum of the gas and kill the well.

Example 5.6—cont'd

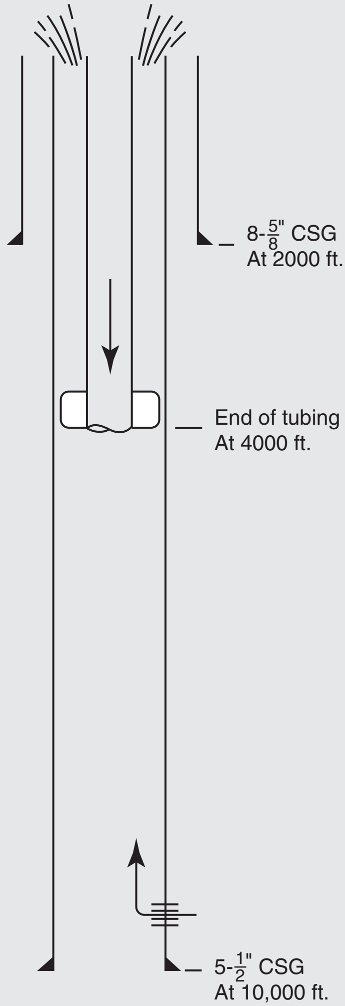

Fig. 5.14 Pioneer Production Company—Martin No. 1–7.

Solution:

The momentum of the gas at 4000 ft can be calculated from Eq. (5.20) as follows:

$$M = \frac{(\rho q)^2 z_i T_i R}{S_g M_a P_i g_c A}$$

Continued

Example 5.6—cont'd

Substituting in the proper units,

$$\rho = 0.0458 \frac{\mathrm{lb}_m}{\mathrm{ft}^3}$$

$$q = 115.74 \frac{\mathrm{ft}^3}{s}$$

$$z_i = 1.00$$

$$T_i = 580° \text{ Rankine}$$

$$R = 1544 \frac{\mathrm{ft} - \mathrm{lb}_f}{°R - \mathrm{lb}_m}$$

$$S_g = 0.60$$

$$M_a = 28.97$$

$$P_i = 45{,}734 \frac{\mathrm{lb}_f}{\mathrm{ft}^2}$$

$$g_c = 32.2 \frac{\mathrm{lb}_m - \mathrm{ft}}{\mathrm{lb}_f - s^2}$$

$$A = 0.1305 \, \mathrm{ft}^2$$

$$M = \frac{[(0.0458)(115.74)]^2 (1.00)(580)(1544)}{(0.60)(28.97)(45,734)(32.2)(0.1305)}$$

$$M = \mathbf{7.53} \, \mathrm{lb}_f$$

The rate at which the kill mud must be pumped can be determined by rearranging Eq. (5.17), substituting in the proper units, and solving for the volume rate of flow as follows:

$$q = \left[\frac{M g_c A}{\rho}\right]^{\frac{1}{2}}$$

where

$$M = 7.53 \, \mathrm{lb}_f$$

$$\rho = 112.36 \frac{\mathrm{lb}_m}{\mathrm{ft}^3}$$

$$A = 0.1305 \ \mathrm{ft}^2$$

$$q = \left[\frac{(7.53)(32.2)(0.1305)}{112.36}\right]^{\frac{1}{2}}$$

$$q = \mathbf{0.5307} \frac{\mathrm{ft}^3}{s}$$

$$q = \mathbf{5.7 \, bbl/min}$$

The preceding example is only one simple instance of the use of the momentum kill technology. The momentum of the wellbore fluids is more difficult to calculate when in multiphase flow. However, the momentum of each component of the flow stream is calculated, and the total momentum is the sum of the momentum of each component.

THE LIQUID PACKER

One of my most successful innovations has been the development of what I have called the liquid packer. On numerous occasions over the course of decades, blowouts were encountered that had resulted from holes in tubing, casing, and drill pipe. In the early years, it was rationalized that the easiest approach would be to run a packer or bridge plug into the well past the compromised tubular and set it. What was soon learned was that, if the well was flowing very hard, the flow would stick or set the packer at the point where the flow was exiting the failed tubular. On a few occasions, we were successful in running the packer below the failure in the tubular, but the strong flow would prevent the packer from setting.

In response to those experiences, I conceived what I named the liquid packer. The idea evolved from my experience with grease heads in wire line work. I had worked on deep high-pressure wells and had difficulty running the wire line under high pressure. Then, the wire line industry developed the grease head for running the wire line into high-pressure wells. For those unfamiliar, the grease head very simply runs the wire line through flow tubes with internal diameter only slightly greater than the outside diameter of the wire line. A very viscous grease is injected into the space between the wire line and the tube and seals that space. The pressure of the well is simply insufficient to overcome the frictional pressure of the grease in the tiny space between the wire line and the flow tube. Higher pressures require more flow tubes.

I reasoned that a system could be designed such that the tolerance between the kill string and the failed tubular would be such that kill mud could be pumped down the kill string faster than the flow from the well could blow it out the annular space between the kill string and the failed tubular. It was a challenging project, but I have always loved the study of fluid dynamics.

One of the best examples of things to do and not to do was the operation at the CHK-140W on the island of Taiwan located 2 h south of Taipei. (For the full story, the reader is referred to IADC/SPE 59120.) The well was initially completed as a dual completion inside 7 in. casing set at 13770 ft. Initial open flow potential from both zones was approximately 28 mmscfpd with a shut-in bottom-hole pressure of 5500 psi. The gas stream contained roughly 50% carbon dioxide. Three years after the initial completion, gas erupted at the surface approximately 90 ft from the wellhead.

The first well control contractor successfully recovered most of the two strings of 2 3/8 in. tubing leaving the top of the short string at 9948 ft and the top of the long string at 10082 ft. The most severe corrosion was found on the tubing strings between 5000 ft and 6300 ft.

Numerous efforts were made to kill the well without success. One involved attempting to pump brine water down the well. On another occasion, 2 3/8 in. tubing was run in the well, and heavy mud was pumped.

On another occasion, an inflatable packer was run into the well. However, when the inflatable packer encountered the cross flow at the surface in the flow cross, the packer element expanded temporarily shutting off the flow. The pressure built up under the packer and blew the packer and two joints of tubing out of the hole and up through the snubbing basket. Fortunately, no one was injured in the incident.

On still another attempt, a modified Baker liner hanger packer was run into the hole. The plan was to run the packer below the corroded interval in the 7 in. casing, set the packer, and kill the well. Unfortunately, the flow from the well set the packer at 6100 ft in the corroded interval, and the blowout continued. Lesson learned; think long and hard before running packers into a blowout.

The inside of the packer was then milled out, and a string of 3½ in. tubing was run through the packer to the top of the fish. Another attempt was made to kill the well by pumping brine water down the 3 ½ in. tubing. The blowout continued.

I was hired by CPC as a consultant initially, and after the series of failures, CPC requested that my company take over the operation. Reluctantly, we did. Our plan forward was simple: mill out the packer and run 5½ in. casing to the top of the fish. Then, pump 20 ppg mud to kill the well and follow the mud with cement to permanently plug and abandon the well.

Over 1 month was required to mill the packer out of the well. The fluid dynamics were modeled. Kill-mud volumes and kill pump rates were determined. The kill string was snubbed into the hole, and the well was killed, plugged, and abandoned pursuant to the program.

Why 5 ½ in. casing? The reasoning was that there was no way to know the extent of the corrosion in the 7 in. casing prior to running the kill string. As a result, the length of the kill string by 7 in. annulus that would be applicable to the determination of the liquid packer could not be known until after the kill string had been run. Therefore, the program had to be as aggressive as possible.

The tolerance between the internal diameter of the 7 in. casing and the outside diameter of the couplings on the 5 ½ in. casing was a concern. As a result, prior to shipment from the United States, the collars on the 5 ½ in. casing kill string had to be turned down to be sure the casing could be run.

The determination of the depth of the corrosion in the 7 in. production casing was clever. As the 5 ½ in. kill string was snubbed into the hole, the pressure on all the annuli was recorded and graphed. Only after the kill string passed the last holes in the 7 in. casing could the pressures at the surface be expected to decline as normally and intuitively expected. Pursuant to the pressure profile, the last hole in the 7 in. casing was at approximately 6230 ft. With the kill string snubbed to a total depth of 9800 ft, the 5 ½ ×7 in. annulus was almost 3600 ft in length, and the kill and control was a certainty.

Over the years, liquid packer kills have been accomplished for tubular combinations from 1 ½ inside 2 7/8 to 5 ½ inside 7 in. One of the most challenging applications of the liquid packer concept occurred at a blowout in the wilds of northern Alberta. The wellbore schematic is presented as Fig. 5.15. Flow from the Keg River at approximately 5800 ft was measured at 10 mmscfpd with 40% H_2S. Since the location was very remote, there was no market, and the well was shut in. The 2 7/8 in. tubing was set in a packer immediately above the perforations, and a plug was set in the end of the tubing.

After setting idle for 18 years, the well blew out at the surface. Diagnostics indicated that the well was flowing up the 2 7/8 in. tubing annulus but there were holes in the tubing near the surface. The condition of the well was deteriorating rapidly. All of the equipment needed for the operation had to be moved in by helicopter. By the time that everything was organized, the 2 7/8 in. tubing had been perforated just above the plug but had parted approximately 300 ft from the surface.

One attempt was made to run an expandable packer on 1 ½ in. coil tubing, but it was not possible to get the packer into the top of the tubing. It seemed that a relief well would be the only successful option. One last attempt was made with a 2 in. coil tubing. After considerable effort, hats off to the fisherman on location, the 2 in. coil tubing was run inside the 2 7/8 in. production tubing. After considerable careful modeling, the 2 in. coil tubing was run to approximately 2000 ft (1700 ft inside

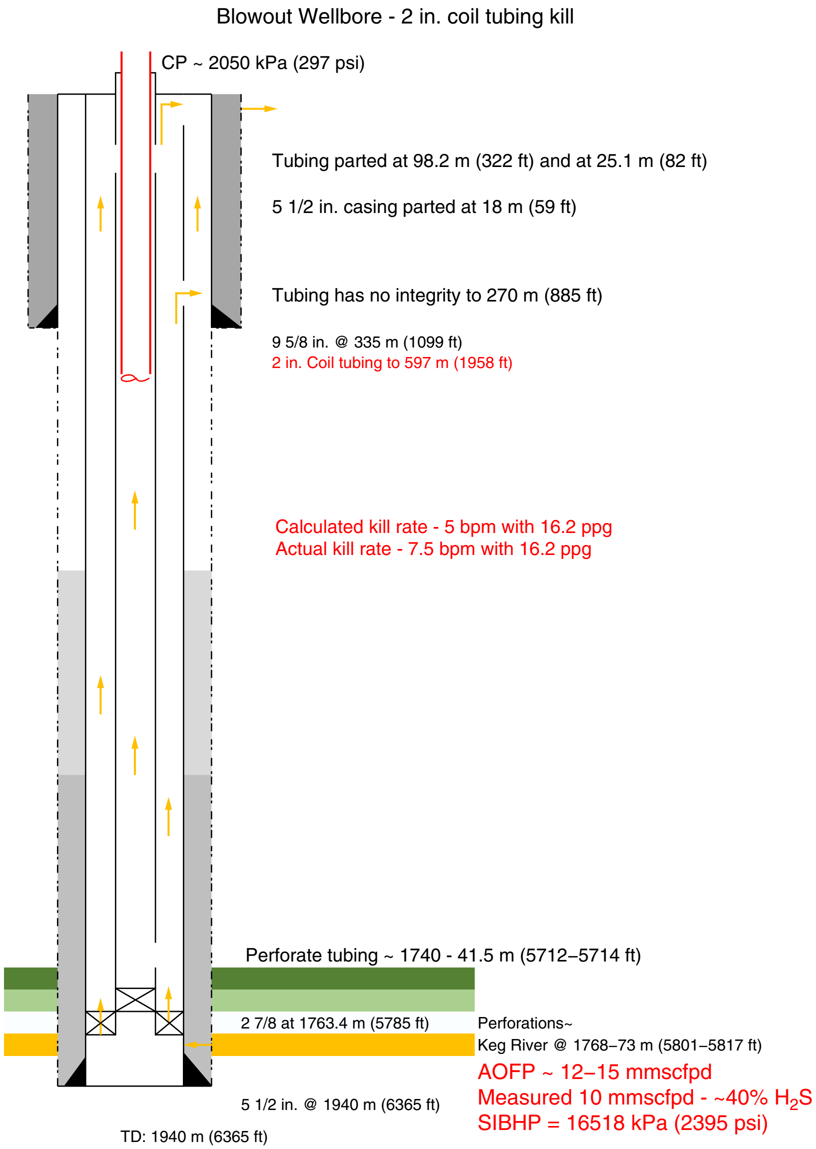

Fig. 5.15 Wellbore schematic of a blowout in northern Alberta.

the 2 7/8 in. production tubing). Pursuant to the modeling, the blowout was killed with kill mud with a density of 16.2 ppg at a rate of 7.5 bpm. A costly relief well was avoided.

One of the most dramatic applications of the liquid packer concept was the well control operation at RN 36 in Rhourde Nouss, Algeria. The wellbore schematic is presented as Fig. 5.16. The 5 ½ in. tubing and all casing

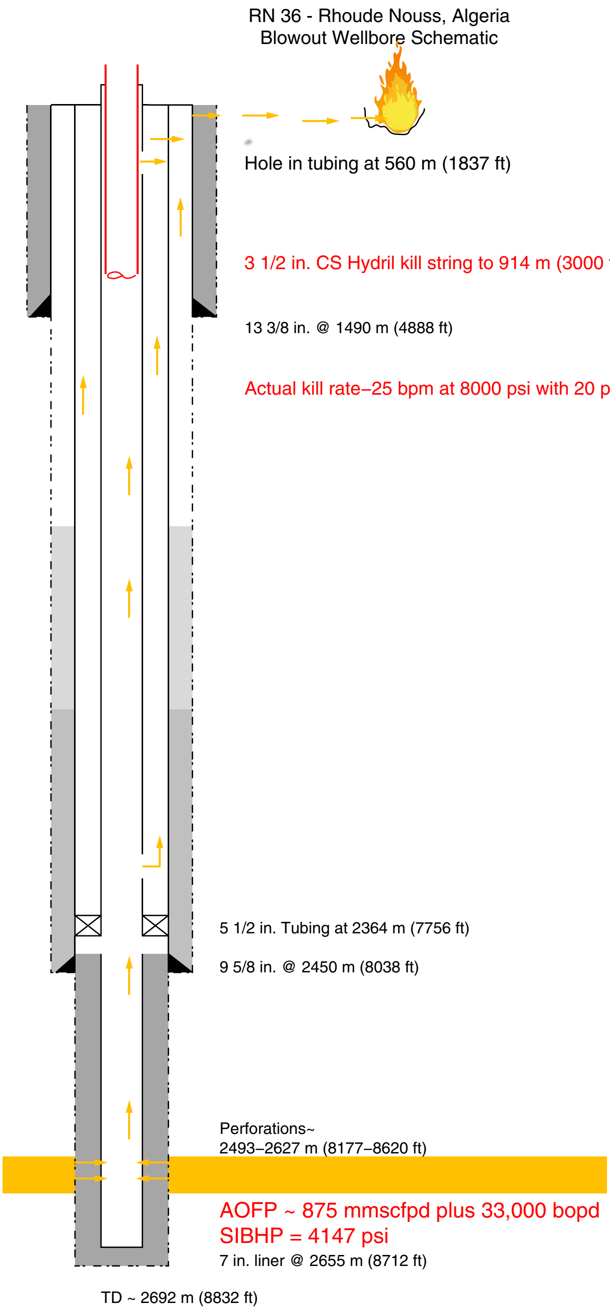

Fig. 5.16 Wellbore schematic of RN 36 in Algeria.

strings were communicated, and the flow erupted to the surface through a water well 300 ft away. Diagnostics determined that the hole in the 5 ½ in. tubing was at 1837 ft and another likely at the packer. Modeling indicated the well could be killed by running 3 ½ in. tubing to 3000 ft and pumping 20 ppg mud at 25 bpm. It worked!

The important thing to remember in considering a liquid packer procedure is to minimize the clearance in the annulus. The cross-sectional area of any annulus is much greater than intuitively expected. Modeling the fluid dynamics is complex and time-consuming but well worth the effort.

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FURTHER READING

[1] Courtesy of Amoco Production Company.

CHAPTER SIX

Special Services in Well Control

0730 hours—commenced snubbing into hole. Well pressure 5000 psi.
1200 hours—400 ft of tubing in hole. Shut down for lunch.
1330 hours—resumed operations. Attempting to snub packer into hole. Snubbing unit operator yells down that he is unable to continue as pipe is trying to bow. Snubbing supervisor goes into basket. Operator attempts to snub into hole. Pipe buckled and started shooting out of the hole. The flow ignited within seconds.

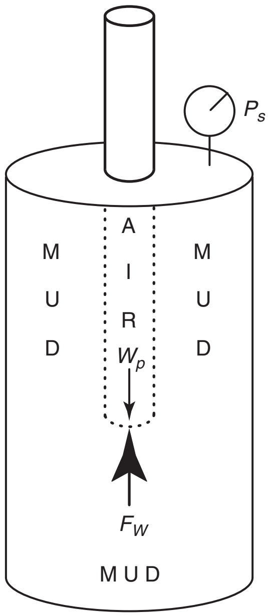
SNUBBING

Snubbing is the process of running or pulling tubing, drill pipe, or other tubulars in the presence of sufficient surface pressure to cause the tubular to be forced out of the hole. That is, in snubbing, the force due to formation pressure's acting to eject the tubular exceeds the buoyed weight of the tubular. As illustrated in Fig. 6.1, the well force, F_w, is greater than the weight of the pipe. The well force, F_w, is a combination of the pressure force, buoyant force, and friction force.

Stripping is similar to snubbing in that the tubular is being run into or pulled out of the hole under pressure; however, in stripping operations, the force resulting from the surface pressure is insufficient to overcome the weight of the string and force the tubular out of the hole (Fig. 6.2).

Snubbing or stripping operations through rams can be performed at any pressure. Snubbing or stripping operations through a good quality annular preventer are generally limited to pressures less than 2000 psi. Operations conducted through a stripper rubber or rotating head should be limited to pressures less than 250 psi. High pressure rotating control devices should be limited to their rated working pressure. Although slower, ram to ram is the safest procedure for conducting operations under pressure.

Blowout and Well Control Handbook
http://dx.doi.org/10.1016/B978-0-12-812674-5.00006-7

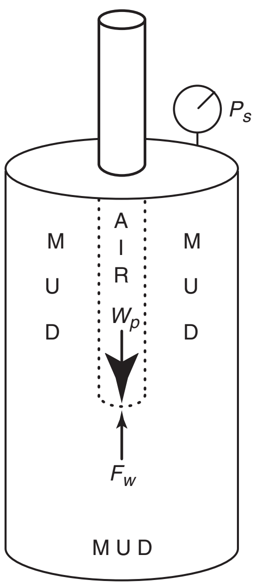


$W_p < F_W$

where: $F_W = F_f - PsAcs + F_b$

W_p = Nominal pipe weight, lb/ft

Fig. 6.1 Snubbing.



$$P_sA + F_b + F_f < W_pL$$

Fig. 6.2 Stripping.

Some of the more common snubbing applications are as follows:

- Tripping tubulars under pressure
- Pressure-control/well-killing operations
- Fishing, milling, or drilling under pressure
- Completion operations under pressure

There are some significant advantages to snubbing operations. Snubbing may be the only option in critical well control operations. In general, high-pressure operations are conducted more safely. For completion operations, the procedures can be performed without kill fluids, thereby eliminating the potential for formation damage.

There are, however, some disadvantages and risks associated with snubbing. Usually, the procedures and operations are more complex. Snubbing is also slower than stripping or conventional tripping. Finally, during snubbing operations, there is always pressure and usually gas at the surface.

EQUIPMENT AND PROCEDURES

The Snubbing Stack

There are many acceptable snubbing stack arrangements. The basic snubbing stack is illustrated in Fig. 6.3. As illustrated, the lowermost rams are blind safety rams. Above the blind safety rams are the pipe safety rams. Above the pipe safety rams is the bottom snubbing ram, followed by a spacer spool and the upper snubbing ram. Since a ram preventer should not be operated with a pressure differential across the ram, an equalizing loop is required to equalize the pressure across the snubbing rams during the snubbing operation. The pipe safety rams are used only when the snubbing rams become worn and require changing.

When a snubbing ram begins to leak, the upper safety ram is closed and the pressure above the upper safety ram is released through the bleed-off line. The snubbing ram is then repaired. The pump-in line can be used to equalize the pressure across the safety ram, and the snubbing operation continued. Since all rams hold pressure from below, an inverted ram must be included below the stack if the snubbing stack is to be tested to pressures greater than well pressure.

The Snubbing Procedure

The snubbing procedure is illustrated beginning with Fig. 6.4. As illustrated in Fig. 6.4, when snubbing into the hole, the tool joint or connection is

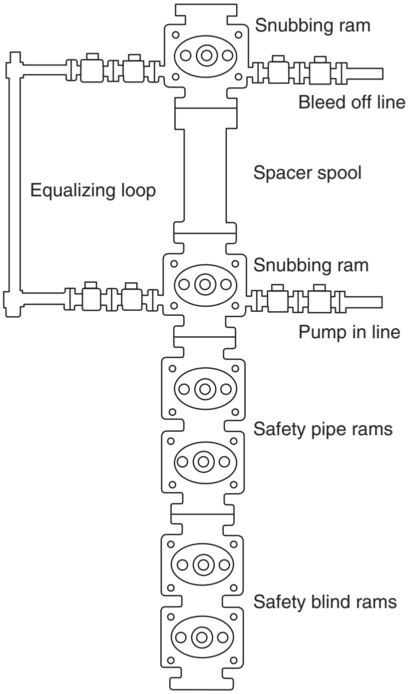


Fig. 6.3 Basic snubbing stack.

above the uppermost snubbing ram, which is closed. Therefore, the well pressure is confined below the upper snubbing ram.

When the tool joint reaches the upper snubbing ram, the lower snubbing ram and equalizing loop are closed, which confines the well pressure below the lower snubbing ram. The pressure above the lower snubbing ram is released through the bleed-off line as shown in Fig. 6.5.

After the pressure is released above the lower snubbing ram, the upper snubbing ram is opened, the bleed-off line is closed, and the connection is lowered to a position immediately above the closed lower snubbing ram as illustrated in Fig. 6.6. The upper snubbing ram is then closed and the equalizing loop is opened, which equalizes the pressure across the lower snubbing ram (Fig. 6.7).

The lower snubbing ram is then opened, and the pipe is lowered through the closed upper snubbing ram until the next connection is immediately above the upper snubbing ram. With the next connection above the upper snubbing ram, the procedure is repeated.

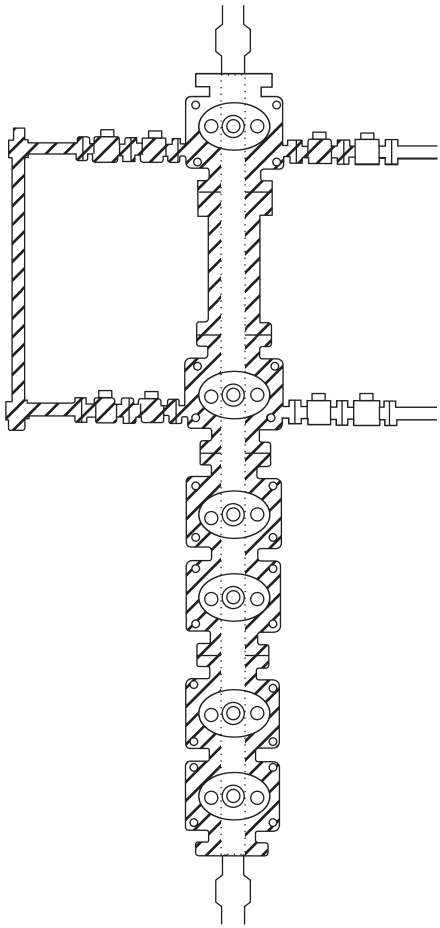


Fig. 6.4 Snubbing into the hole, upper ram closed with tool joint above upper ram.

Snubbing Equipment

If a rig is on the hole, it can be used to snub the pipe into the hole. The rig-assisted snubbing equipment is illustrated in Fig. 6.8. With the stationary slips released and the traveling slips engaged, the traveling block is raised, and the pipe is forced into the hole. At the bottom of the stroke, the stationary slips are engaged, and the traveling slips are released.

The counterbalance weights raise the traveling slips as the traveling block is lowered. At the top of the stroke, the traveling slips are engaged, the stationary slips are released, and the procedure is repeated. The conventional snubbing system moves the pipe. If drilling operations under pressure are required, a power swivel must be included.

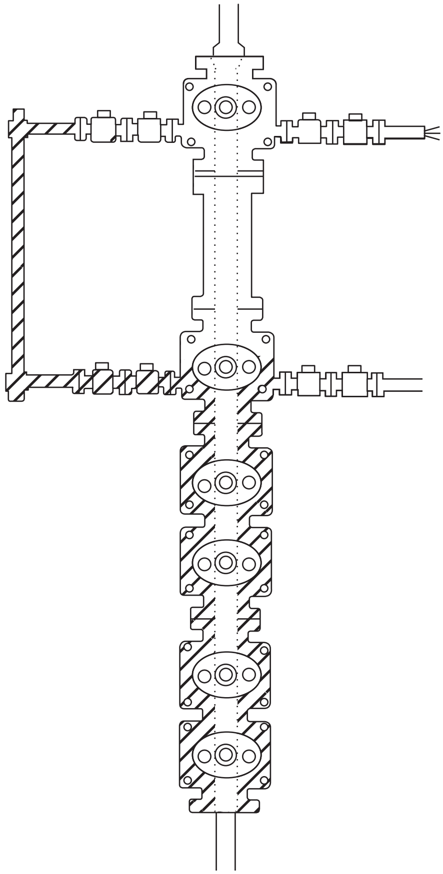


Fig. 6.5 Snubbing into the hole, lower ram closed with pressure bled off.

A hydraulic snubbing unit can be used with or without a rig. A hydraulic snubbing unit is illustrated in Fig. 6.9. With a hydraulic snubbing unit, all work is done from the work basket with the hydraulic system, replacing the rig. The hydraulic system has the capability to circulate and rotate for cleaning out or drilling. If a rig is on the well, the rig can assist with running and pulling the pipe.

Theoretical Considerations

As shown in Fig. 6.1, snubbing is required when the well force, F_w, exceeds the total weight of the tubular. The snubbing force is equal to the net upward force as illustrated in Eq. (6.1) and Fig. 6.1:

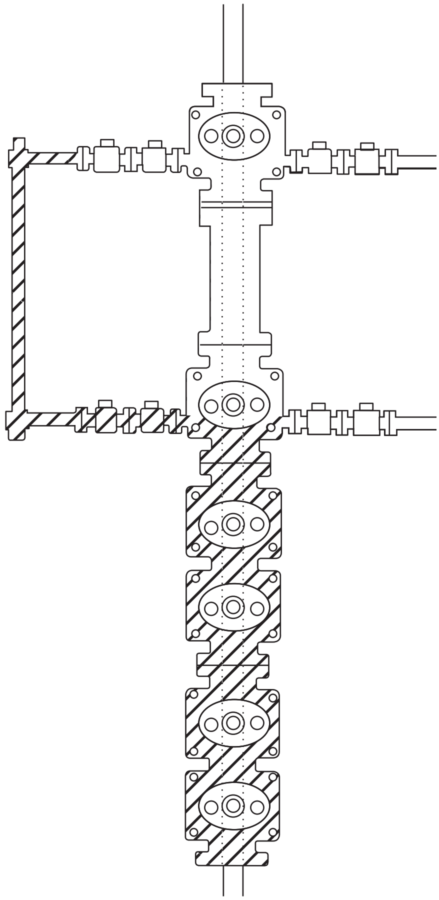


Fig. 6.6 Snubbing into the hole, with tool joint at lower ram.

$$F_{sn} = W_p L - \left(F_f + F_B + F_{wp}\right) \tag{6.1}$$

where

W_p = nominal weight of the pipe, lb/ft
L = length of pipe, feet
F_f = friction force, lb_f
F_B = buoyant force, lb_f
F_{wp} = well pressure force, lb_f

The well pressure force, F_{wp}, is given by Eq. (6.2):

$$F_{wp} = 0.7854 D_p^2 P_s \tag{6.2}$$

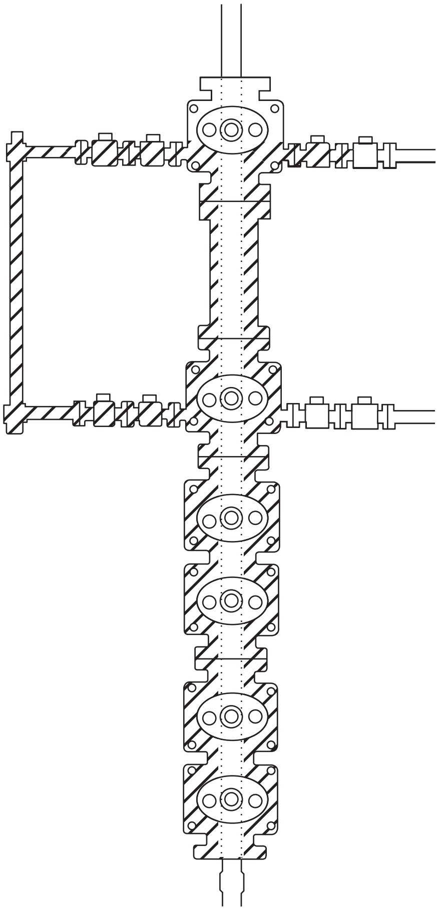


Fig. 6.7 Snubbing into the hole, top ram closed, pressure equalized, and bottom ram opened.

where

P_s = surface pressure, psi

D_p = outside diameter of tubular exposed to P_s, in.

As shown in Eq. (6.2), the diameter of the pipe within the seal element must be considered. When running pipe through an annular or stripper, the outside diameter of the connection is the determining variable. When stripping or snubbing pipe from ram to ram, only the pipe body is contained within the seal elements; therefore, the outside diameter of the tube will determine the force required to push the pipe into the well. With drill pipe, there is a significant difference between the diameter of the pipe body and the tool joint.

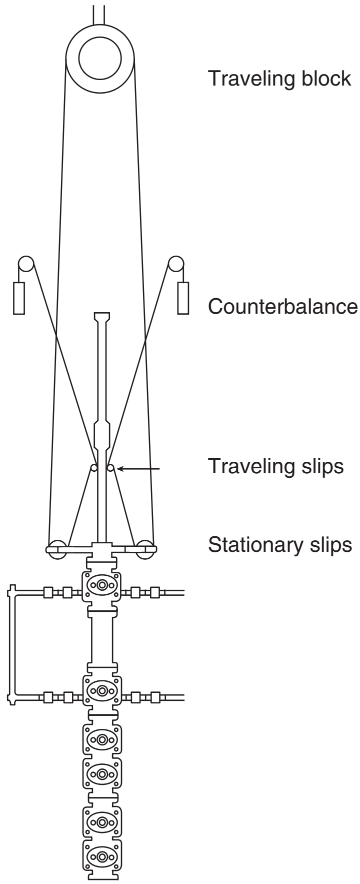


Fig. 6.8 Conventional or rig-assisted snubbing unit.

Example 6.1 illustrates the calculation of the wellhead pressure force:

Example 6.1

Given:

Surface pressure, $P_s = 1500$ psi

Work string = 4.5 in. drill pipe

Pipe OD, $D_p = 4.5$ in.

Connection OD, $D_{pc} = 6.5$ in.

Required:

The well pressure force when the annular is closed on

1. The tube (Fig. 6.10)
2. The connection (Fig. 6.11)

Continued

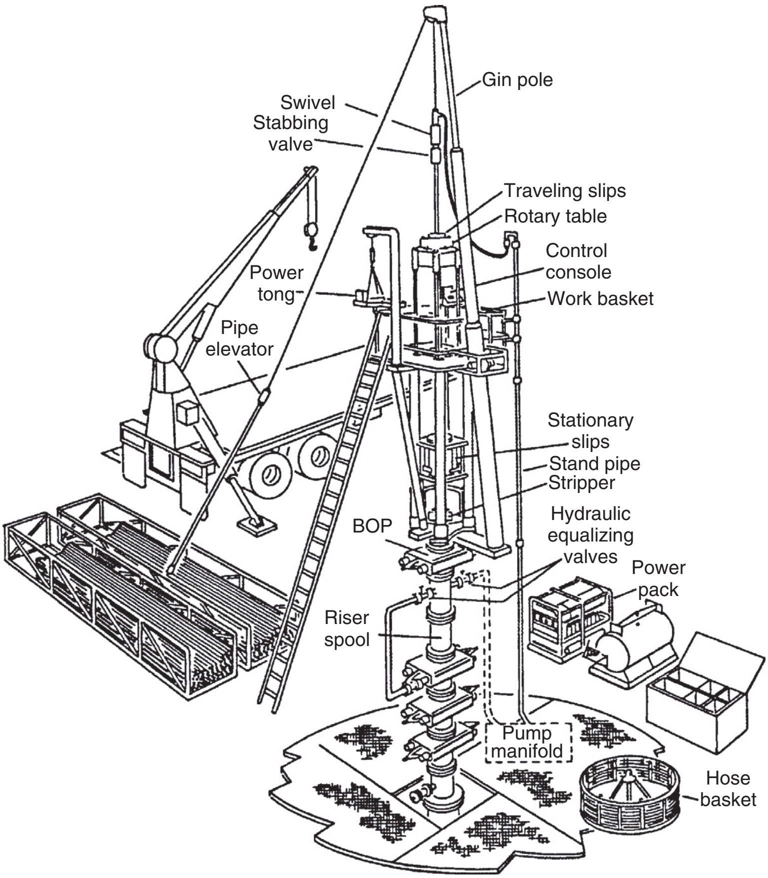


Fig. 6.9 Hydraulic snubbing unit without rig assist.

Example 6.1—cont'd

Solution:

1. When the annular is closed on the tube, the force associated with the pressure can be determined using Eq. (6.2):

$$F_{wp} = 0.7854 D_p^2 P_s$$
$$F_{wp} = 0.7854\left(4.5^2\right)(1500)$$
$$F_{wp} = \mathbf{23,857}\,\text{lb}_f$$

2. When the annular is closed on a tool joint, the force is calculated using the diameter of the connection:

$$F_{wp} = 0.7854\left(6.5^2\right)(1500)$$
$$F_{wp} = \mathbf{49,775}\,\text{lb}_f$$

Example 6.1—cont'd

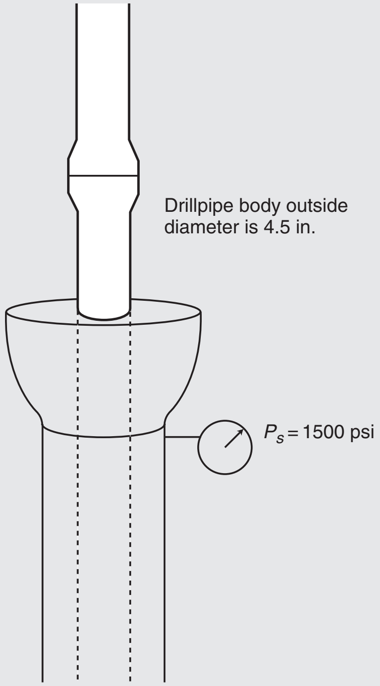


Fig. 6.10 Snubbing drill pipe through the annular.

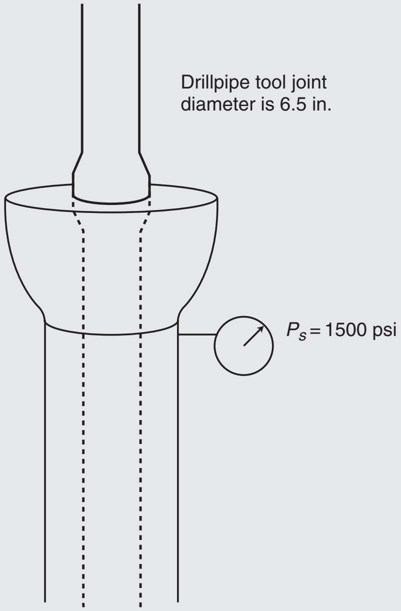


Fig. 6.11 Snubbing the tool joint through the annular.

In addition to the pressure area force, the friction force must be considered. Friction is that force that is tangent to the surface of contact between two bodies and resisting movement. Static friction is the force that resists the initiation of movement. Kinetic friction is the force resisting movement when one body is in motion relative to the other. The force required to overcome static friction is always greater than that required to maintain movement (kinetic friction).

Since friction is a resistance to motion, it acts in the direction opposite to the pipe movement. Friction acts upward when snubbing or stripping into a well and downward when snubbing or stripping out of a well. The magnitude of the force required to overcome friction is a function of the roughness of the surface areas in contact, the total surface area, the lubricant being used, and the closing force applied to the BOP.

Additional friction or drag may result between the snubbing string and the wall of the hole. In general, the larger the dogleg severity, inclination, and tension (or compression) in the snubbing string, the greater the friction due to drag.

In addition to the forces associated with pressure and friction, the buoyant force affects the snubbing operation. Buoyancy is the force exerted by a fluid (either gas or liquid) on a body wholly or partly immersed and is equal to the weight of the fluid displaced by the body.

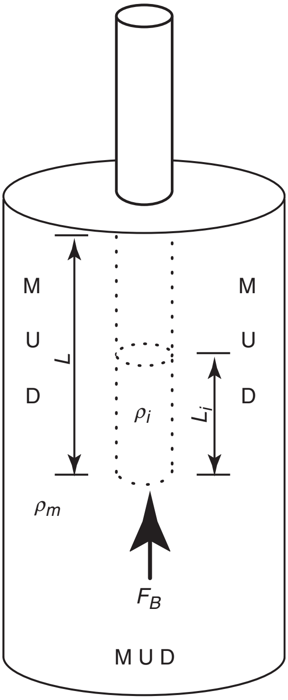
As illustrated in Fig. 6.12, the buoyant force, F_B, is given by Eq. (6.3):

$$F_B = 0.7854\left(\rho_m D_p^2 L - \rho_i D_i^2 L_i\right) \tag{6.3}$$

where

ρ_m = mud gradient in annulus, psi/ft
ρ_i = fluid gradient inside pipe, psi/ft
D_p = outside diameter of pipe, in.
D_i = inside diameter of pipe, in.
L = length of pipe below BOP, ft
L_i = length of column inside pipe, ft

If the pipe is being snubbed into the hole dry, the density of the air is negligible, and the $\rho_i D_i^2 L_i$ term is negligible. If the inside of the pipe is full or partially full, the $\rho_i D_i^2 L_i$ term cannot be ignored. If the annulus is partially filled with gas, the $\rho_m D_p^2 L$ term must be broken into its component parts. If the annulus contains muds of different densities, each must be considered. The determination of the buoyant force is illustrated in Example 6.2, and Eq. (6.3) becomes



$F_B = 0.7854(\rho_m D_p^2 L - \rho_i D_i^2 L_i)$

Fig. 6.12 The buoyant force.

$$F_B = 0.7854\left[(\rho_{m1}L_1 + \rho_{m2}L_2 + \rho_{m3}L_3 + \cdots + \rho_{mx}L_x)D_p^2 - \rho_i L_i D_i^2\right]$$

where

L_1 = column length of fluid having a density gradient ρ_{m1}
L_2 = column length of fluid having a density gradient ρ_{m2}
L_3 = column length of fluid having a density gradient ρ_{m3}
L_x = column length of fluid having a density gradient ρ_{mx}

Example 6.2
Given:
Schematic = Fig. 6.12
Mud gradient, $\rho_m = 0.624$ psi/ft
Length of pipe, $L = 2000$ ft
Tubular = $4\frac{1}{2}$in 16.6 lb/ft drill pipe
Tubular is dry.

Continued

Example 6.2—cont'd

Required:

The buoyant force

Solution:

The buoyant force is given by Eq. (6.3):

$$F_B = 0.7854\left(\rho_m D_p^2 L - \rho_i D_i^2 L_i\right)$$

With dry pipe, Eq. (6.3) reduces to

$$F_B = 0.7854 \rho_m D_p^2 L$$
$$F_B = 0.7854(0.624)\left(4.5^2\right)(2000)$$
$$F_B = \mathbf{19,849}\,\mathrm{lb}_f$$

In this example, the buoyant force is calculated to be 19,849 lb_f. The buoyant force acts across the exposed cross-sectional area that is the end of the drill pipe and reduces the effective weight of the pipe. Without the well pressure force, F_{wp}, and the friction force, F_f, the effective weight of the 2000 ft of drill pipe would be given by Eq. (6.4):

$$W_{eff} = W_p L - F_B \tag{6.4}$$

Example 6.3

Given:

Example 6.2

Required:

Determine the effective weight of the $4\frac{1}{2}$-in. drill pipe.

Solution:

The effective weight, W_{eff}, is given by Eq. (6.4):

$$W_{eff} = W_p L - F_B$$
$$W_{eff} = 16.6(2000) - 19,849$$
$$W_{eff} = \mathbf{13,351}\,\mathrm{lbs}$$

As illustrated in this example, the weight of the drill pipe is reduced from 33,200 to 13,351 lb by the buoyant force.

The maximum snubbing or stripping force required occurs when the string is first started, provided the pressure remains constant. At this point, the weight of the string and the buoyant force are minimal and may generally be ignored. Therefore, the maximum snubbing force, F_{snmx}, can be calculated from Eq. (6.5):

$$F_{snmx} = F_{wp} + F_f \tag{6.5}$$

where

F_{snmx} = maximum snubbing force, lb_f
F_{wp} = well pressure force, lb_f
F_f = frictional pressure force, lb_f

As additional pipe is run in the hole, the downward force attributable to the buoyed weight of the string increases until it is equal to the well pressure force, F_{wp}. This is generally referred to as the balance point and is the point at which the snubbing string will no longer be forced out of the hole by well pressure. That is, as illustrated in Fig. 6.13, at the balance point, the well force, F_w, is exactly equal to the weight of the tubular being snubbed into the hole. The length of empty pipe at the balance point is given by Eq. (6.6):

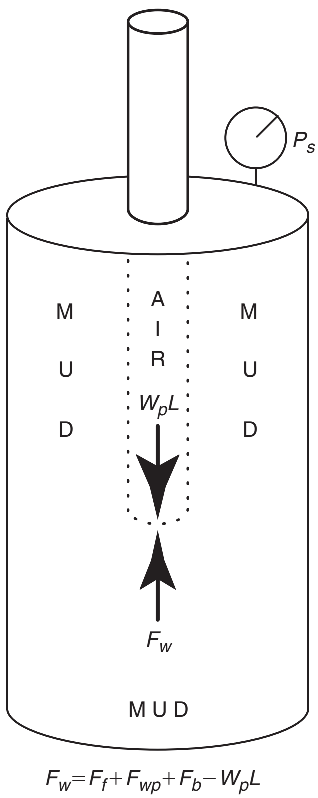


Fig. 6.13 Balance point.

$$L_{bp} = \frac{F_{snmx}}{W_p - 0.0408\rho D_p^2} \tag{6.6}$$

where

L_{bp} = length at balance point, feet
F_{snmx} = maximum snubbing force, lb_f
W_p = nominal pipe weight, lb/ft
ρ = mud density, ppg
D_p = outside diameter of tubular, in.

After the pipe is filled, the net downward force is a positive snubbing force as given by Eq. (6.1).

In a normal snubbing situation, the work string is run to a point just above the balance point without filling the work string. While snubbing, the well force must be sufficiently greater than the weight of the pipe to cause the slips to grip the pipe firmly. After the pipe is filled, the weight of the pipe should be sufficient to cause the slips to grip the pipe firmly. This practice increases the string weight and reduces the risk of dropping the work string near the balance point.

The determination of the balance point is illustrated in Example 6.4:

Example 6.4

Given:

$4\frac{1}{2}$ in. 16.6 lb/ft drill pipe is to be snubbed ram to ram into a well containing 12 ppg mud with a shut-in wellhead pressure of 2500 psi. The friction contributable to the BOP ram is 3000 lb_f. The internal diameter of the drill pipe is 3.826 in.

Required:

1. The maximum snubbing force required
2. Length of empty pipe to reach the balance point
3. The net downward force after the pipe is filled at the balance point

Solution:

1. The maximum snubbing force is given by Eq. (6.5):

$$F_{snmx} = F_{wp} + F_f$$

Combining Eqs. (6.5) and (6.2),

$$F_{snmx} = 0.7854 D_p^2 P_s + F_f$$
$$F_{snmx} = 0.7854\left(4.5^2\right)(2500) + 3000$$
$$F_{snmx} = \mathbf{42,761}\ lb_f$$

Example 6.4—cont'd

2. The length of the empty pipe at the balance point is given by Eq. (6.6):

$$L_{bp} = \frac{F_{snmx}}{W_p - 0.0408\rho D_p^2}$$
$$L_{bp} = \frac{42,761}{16.60 - 0.0408(12)(4.5^2)}$$
$$L_{bp} = \mathbf{6396}\,\text{ft}$$

3. The net force after the pipe is filled is given by Eq. (6.1):

$$F_{sn} = W_p L - \left(F_f + F_B + F_{wp}\right)$$
$$\text{Since } F_f + F_{wp} = F_{snmx},$$
$$\text{Then } F_f + F_{wp} = 42,761\,\text{lb}_f$$

The buoyant force, F_B, is given by Eq. (6.3):

$$F_B = 0.7854\left(\rho_m D_p^2 L - \rho_m D_i^2 L_i\right)$$
$$F_B = 0.7854[(0.624)\left(4.5^2\right)(6396) - (0.624)\left(3.826^2\right)(6396)]$$
$$F_B = \mathbf{17,591}\,\text{lbs}$$

Therefore,

$$F_{sn} = 6396(16.6) - 42,761 - 17,591$$
$$F_{sn} = \mathbf{45,822}\,\text{lbs}$$

EQUIPMENT SPECIFICATIONS

In hydraulic snubbing operations, the hoisting power required is produced by pressure applied to a multicylinder hydraulic jack. The jack cylinder is represented in Fig. 6.14. Pressure is applied to different sides of the jack cylinder depending on whether snubbing or stripping is being done. During snubbing, the jack cylinders are pressurized on the piston rod side and on the opposite side for lifting or stripping.

Once the effective area of the jack is known, the force required to lift or snub a work string can be calculated using Eqs. (6.7) and (6.8):

$$F_{snub} = 0.7854 P_{hyd} N_c \left(D_{pst}^2 - D_r^2\right) \tag{6.7}$$

$$F_{lift} = 0.7854 P_{hyd} N_c D_{pst}^2 \tag{6.8}$$

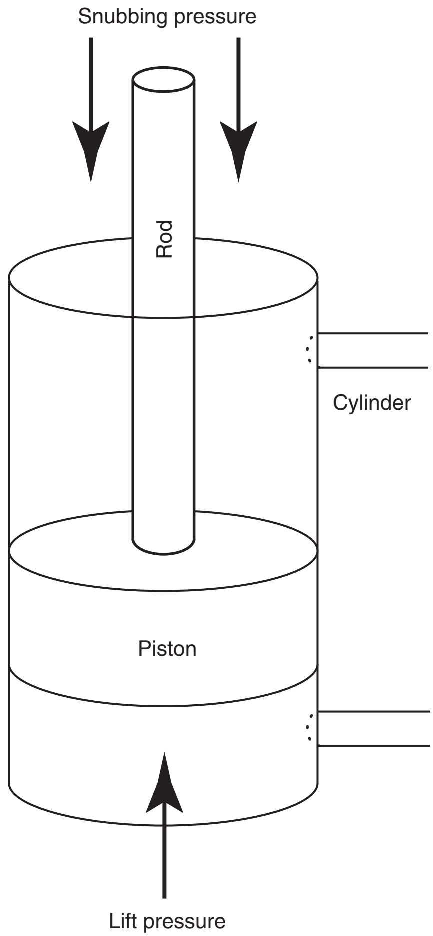


Fig. 6.14 Schematic of hydraulic jack cylinder.

where

F_{snub} = snubbing force, lb_f

F_{lift} = lifting force, lb_f

D_{pst} = outside diameter of piston rod in jack cylinder, in.

N_c = number of active jack cylinders

P_{hyd} = hydraulic pressure needed on jacks to snub/lift, psi

The determination of the snubbing and lifting force is illustrated in Example 6.5:

Example 6.5

Given:

A hydraulic snubbing unit Model 225 with four jack cylinders. Each cylinder has a 5 in diameter bore and a 3.5 in diameter piston rod. The maximum hydraulic pressure is 2500 psi.

Required:

1. The snubbing force, F_{snub}, at the maximum pressure
2. The lifting force, F_{lift}, at the maximum pressure

Solution:

1. The snubbing force at 2500 psi is given by Eq. (6.7):

$$F_{snub} = 0.7854 P_{hyd} N_c \left(D_{pst}^2 - D_r^2 \right)$$
$$F_{snub} = 0.7854(2500)(4)\left(5^2 - 3.5^2\right)$$
$$F_{snub} = \mathbf{100,139}\ \mathrm{lb}_f$$

2. Calculate the lifting force at 2500 psi using Eq. (6.8):

$$F_{lift} = 0.7854 P_{hyd} N_c D_{pst}^2$$
$$F_{lift} = 0.7854(2500)(4)\left(5^2\right)$$
$$F_{lift} = \mathbf{196,350}\ \mathrm{lb}_f$$

The hydraulic pressure required to snub or lift in the hole can be calculated by rearranging Eq. (6.8).

Example 6.6 illustrates the determination of the hydraulic pressure required for a specific lifting or snubbing force.

Example 6.6

Given:

The same hydraulic snubbing unit as given in Example 6.5. The hydraulic jacks have an effective snubbing area of 40.06 in.^{2} and an effective lifting area of 78.54 in.^{2}

Required:

1. The hydraulic jack pressure required to produce a snubbing force of 50,000 lb
2. The hydraulic jack pressure required to produce a lifting force of 50,000 lb

Continued

Example 6.6—cont'd

Solution:

1. The hydraulic pressure required for snubbing is determined by rearranging Eq. (6.7):

$$P_{shyd} = \frac{F_{snub}}{0.7854\left(D_{pst}^2 - D_r^2\right)N_c} \tag{6.9}$$

$$P_{shyd} = \frac{50,000}{0.7854(5^2 - 3.5^2)4}$$

$$P_{shyd} = \frac{50,000}{40.06}$$

$$P_{shyd} = \mathbf{1248}\ \text{psi}$$

2. The hydraulic pressure required for lifting is determined by rearranging Eq. (6.8):

$$P_{lhyd} = \frac{F_{lift}}{0.7854D_{pst}^2N_c} \tag{6.10}$$

$$P_{lhyd} = \frac{50,000}{0.7854(5^2)4}$$

$$P_{lhyd} = \frac{50,000}{78.54}$$

$$P_{lhyd} = \mathbf{637}\ \text{psi}$$

Table 6.1 is a listing of the dimensions and capacity of snubbing units normally utilized.

BUCKLING CONSIDERATIONS

After determining the required snubbing force, this force must be compared with the compressive load that the work string can support without buckling. Pipe buckling occurs when the compressive force placed on the work string exceeds the resistance of the pipe to buckling. The smallest force at which a buckled shape is possible is the critical force. Buckling occurs first in the maximum unsupported length of the work string, which is usually in the window area of the snubbing unit if a window guide is not installed.

In snubbing operations, buckling must be avoided at all costs. Once the pipe buckles, catastrophic failure will certainly follow. When the pipe fails,

Table 6.1 Dimensions and capacities of snubbing units

Model	**150**	**225**	**340**	**600**
Number of cylinders	4	4	4	4
Cylinder diameter (in)	4.0	5.0	6.0	8.0
Piston rod diameter (in)	3.0	3.5	4.0	6.0
Effective lift area (in.^{2})	50.27	78.54	113.10	201.06
Lifting capacity at 3000 psi (lb)	150,796	235,619	339,292	603,186
Effective snub area (in.^{2})	21.99	40.06	62.83	87.96
Snubbing capacity at 3000 psi (lb)	65,973	120,166	188,496	263,894
Effective regenerated lift area (in.^{2})	28.27	38.48	50.27	113.10
Regenerated lift capacity at 3000 psi (lb)	84,810	115,440	150,810	339,300
Block speed down (fpm)	361	280	178	137
Block speed up (fpm)	281	291	223	112
Bore through unit (in)	8	11	11	14
Stroke (in)	116	116	116	168
Rotary torque (ft-lb)	1000	2800	2800	4000
Jack weight (lb)	5800	8500	9600	34,000
Power unit weight (lb)	7875	8750	8750	11,000

the remainder of the string is usually ejected from the well. The flying steel can seriously injure or kill those in the work area. After that, wells have been known to blow out of control and ignite.

When the work string is subjected to a compressive load, two types of buckling may occur. Elastic or long-column buckling occurs along the major axis of the work string. The pipe bows out from the centerline of the wellbore as shown in Fig. 6.15A. Inelastic or local-intermediate buckling occurs along the longitudinal axis of the work string as shown in Fig. 6.15B.

Equations describing critical buckling loads were derived by the great mathematician Leonhard Euler in 1757. His original concepts remain valid. However, in oil-field work, these concepts have been expanded somewhat.

As illustrated in Fig. 6.16, the buckling load is a function of the slenderness ratio. In order to determine the type of buckling that may occur in the work string, the column slenderness ratio, S_{rc}, is compared with the effective slenderness ratio, S_{re}, of the work string. If the effective slenderness ratio, S_{re}, is greater than the column slenderness ratio, S_{rc} ($S_{re} > S_{rc}$), elastic or long-column buckling will occur. If the column slenderness ratio, S_{rc}, is greater than the effective slenderness ratio, S_{rc} ($S_{rc} > S_{re}$), inelastic or local-

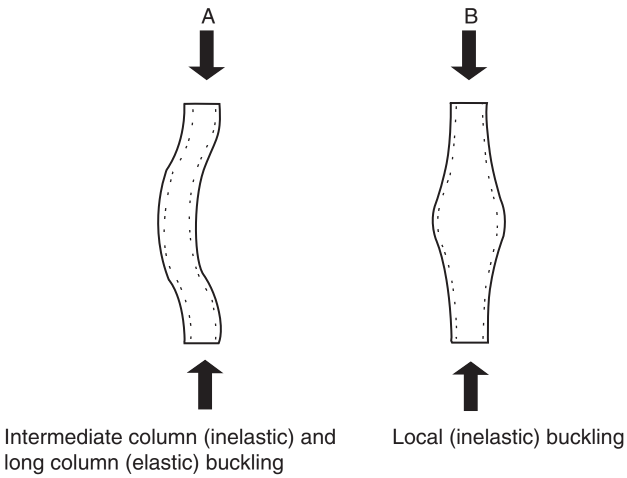


Fig. 6.15 Types of buckling in a snubbing operation.

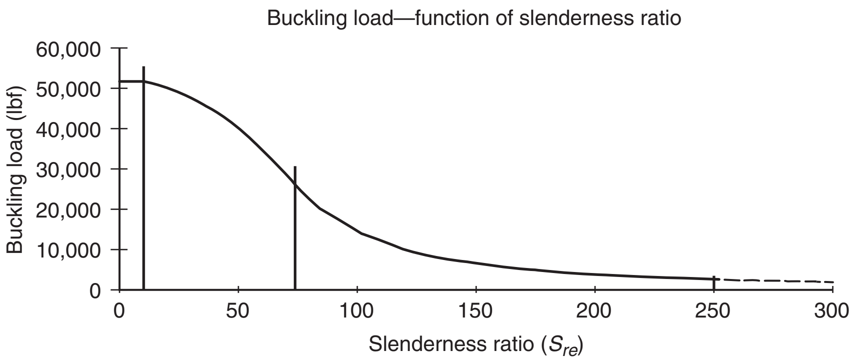


Fig. 6.16 Plot of buckling load versus slenderness ratio.

intermediate buckling will occur. The column slenderness ratio, S_{rc}, divides elastic and inelastic buckling.

The column slenderness ratio, S_{rc}, is given by Eq. (6.11):

$$S_{rc} = 4.44\left(\frac{E}{F_y}\right)^{\frac{1}{2}} \tag{6.11}$$

where

E = modulus of elasticity, psi

F_y = yield strength, psi

The effective slenderness ratio, S_{re}, is given by the larger result of Eqs. (6.12) and (6.13):

$$S_{re} = \frac{4U_L}{\left(D_p^2 + D_i^2\right)^{\frac{1}{2}}} \tag{6.12}$$

$$S_{re} = \left(4.8 + \frac{D_i + t}{450t}\right)\left(\frac{D_i + t}{2t}\right)^{\frac{1}{2}} \tag{6.13}$$

where

U_L = unsupported length, in.
t = wall thickness, in.
D_p = outside diameter of the tubular, in.
D_i = inside diameter of the tubular, in.

Inelastic column buckling can occur if the effective slenderness ratio, S_{re}, is less than the column slenderness ratio, S_{rc}, and is equal to or less than 250 ($S_{re} < S_{rc}$). Inelastic column buckling can be either local or intermediate. Whether inelastic buckling is local or intermediate is determined by a comparison of the effective slenderness ratios determined from Eqs. (6.12) and (6.13).

If Eq. (6.12) results in an effective slenderness ratio less than that obtained from Eq. (6.13), local buckling occurs. If Eq. (6.13) results in an effective slenderness ratio less than Eq. (6.12) (and also less than S_{rc}) ($S_{rc} > S_{re12} > S_{re13}$), intermediate-column buckling occurs. In either situation, a compressive load, which will cause a work string to buckle, is known as the buckling load, P_{bkl}, and is defined by Eq. (6.14):

$$P_{bkl} = F_y\left(D_p^2 - D_i^2\right)\left[\frac{0.7854S_{rc}^2 - 0.3927S_{re}^2}{S_{rc}^2}\right] \tag{6.14}$$

for

$S_{re} < S_{rc}$—inelastic buckling
$S_{re12} < S_{re13}$—local buckling
$S_{rc} > S_{re12} > S_{re13}$—intermediate buckling

where

F_y = yield strength, psi
D_i = inside diameter of the tubular, in.
D_p = outside diameter of the tubular, in.
S_{re} = effective slenderness ratio, dimensionless
S_{rc} = column slenderness ratio, dimensionless

In inelastic buckling, the buckling load, P_{bkl}, can be increased by increasing the yield strength, size, and weight of the work string or decreasing the unsupported section length.

Elastic (long-column) buckling is critical if the effective slenderness ratio, S_{re}, is greater than the column slenderness ratio, S_{rc}, and the effective slenderness ratio is equal to or less than 250 ($S_{re} \leq 250$). When these conditions exist, the buckling load, P_{bkl}, is defined by Eq. (6.15):

$$P_{bkl} = \frac{225(10^6)\left(D_p^2 - D_i^2\right)}{S_{re}^2} \tag{6.15}$$

for

$S_{re} > S_{rc}$ and $S_{re} \leq 250$—long-column buckling

Under this condition, the buckling load, P_{bkl}, can be increased by decreasing the unsupported section length or increasing the size and weight of the work string. Consider the following examples:

Example 6.7

Given:

Work string:

Pipe OD $= 2\frac{3}{8}$ in
Nominal pipe weight $= 5.95$ lb/ft
Pipe grade = P-105
Unsupported length, $U_L = 23.5$ in
Modulus elasticity, $E = 29 \times 10^6$ psi
Yield strength, $F_y = 105{,}000$ psi
Outside diameter, $D_p = 2.375$ in
Inside diameter, $D_i = 1.867$ in
Wall thickness, $t = 0.254$ in

Required:

The buckling load

Solution:

The column slenderness ratio is given by Eq. (6.11):

$$S_{rc} = 4.44\left(\frac{E}{F_y}\right)^{\frac{1}{2}}$$

$$S_{rc} = 4.44\left(\frac{29(10^6)}{105{,}000}\right)^{\frac{1}{2}}$$

$$S_{rc} = \mathbf{73.79}$$

Example 6.7—cont'd

The effective slenderness ratio, S_{re}, will be the greater value as calculated from Eqs. (6.12) and (6.13).

Eq. (6.12) gives

$$S_{re} = \frac{4U_L}{\left(D_p^2 + D_i^2\right)^{\frac{1}{2}}}$$

$$S_{re} = \frac{4(23.5)}{(2.375^2 + 1.867^2)^{\frac{1}{2}}}$$

$$S_{re} = \mathbf{31.12}$$

Eq. (6.13) gives

$$S_{re} = \left(4.8 + \frac{D_i + t}{450t}\right)\left(\frac{D_i + t}{2t}\right)^{\frac{1}{2}}$$

$$S_{re} = \left(4.8 + \frac{1.867 + 0.254}{450(0.254)}\right)\left(\frac{1.867 + 0.254}{2(0.254)}\right)^{\frac{1}{2}}$$

$$S_{re} = \mathbf{9.85}$$

Therefore, the correct effective slenderness ratio is the greater and is given by Eq. (6.12) as 31.12.

Since S_{re} (31.12) is $< S_{rc}$ (73.79) and S_{re} is ≤ 250, failure will be in the intermediate (inelastic) mode, and the buckling load is given by Eq. (6.14):

$$P_{bkl} = F_y\left(D_p^2 - D_i^2\right)\left[\frac{0.7854S_{rc}^2 - 0.3927S_{re}^2}{S_{rc}^2}\right]$$

$$P_{bkl} = (105,000)\left(2.375^2 - 1.867^2\right) \times \left[\frac{0.7854(73.79^2) - 0.3927(31.12^2)}{73.79^2}\right]$$

$$P_{bkl} = \mathbf{161,907}\ \mathrm{lb}_f$$

Consider the following example of a buckling load due to long-column mode failure:

Example 6.8

Given:

Work string:

Nominal pipe OD = 1 in

Nominal pipe weight = 1.80 lb/ft

Pipe grade = P-105

Unsupported length, $U_L = 36.0$ in

Modulus of elasticity, $E = 29 \times 10^6$ psi

Continued

Example 6.8—cont'd

Yield strength, $F_y = 105{,}000$ psi
Outside diameter, $D_p = 1.315$ in
Inside diameter, $D_i = 1.049$ in
Wall thickness, $t = 0.133$ in

Required:
The buckling load

Solution:
The column slenderness ratio is calculated using Eq. (6.11):

$$S_{rc} = 4.44\left(\frac{E}{F_y}\right)^{\frac{1}{2}}$$
$$S_{rc} = 4.44\left(\frac{29(10^6)}{105{,}000}\right)^{\frac{1}{2}}$$
$$S_{rc} = \mathbf{73.79}$$

The effective slenderness ratio, S_{re}, will be the greater value as calculated from Eqs. (6.12) and (6.13). Eq. (6.12) gives

$$S_{re} = \frac{4U_L}{\left(D_p^2 + D_i^2\right)^{\frac{1}{2}}}$$
$$S_{re} = \frac{4(36)}{(1.315^2 + 1.049^2)^{\frac{1}{2}}}$$
$$S_{re} = \mathbf{85.60}$$

Eq. (6.13) gives

$$S_{re} = \left(4.8 + \frac{D_i + t}{450t}\right)\left(\frac{D_i + t}{2t}\right)^{\frac{1}{2}}$$
$$S_{re} = \left(4.8 + \frac{1.049 + 0.133}{450(0.133)}\right)\left(\frac{1.049 + 0.133}{2(0.133)}\right)^{\frac{1}{2}}$$
$$S_{re} = \mathbf{10.16}$$

The greater effective slenderness ratio is given by Eq. (6.12) and is 85.60.

Since S_{rc} (73.79) is $<$ S_{re} (85.60) and S_{re} is ≤ 250, failure will be in the long-column mode, and Eq. (6.15) will be used to determine the buckling load:

$$P_{bkl} = \frac{225(10^6)\left(D_p^2 - D_i^2\right)}{S_{re}^2}$$
$$P_{bkl} = \frac{225(10^6)(1.315^2 - 1.049^2)}{85.60^2}$$
$$P_{bkl} = \mathbf{19{,}309}\ \text{lbs}$$

Local inelastic buckling is illustrated by Example 6.9.

Example 6.9

Given:

Example 6.8, except that the unsupported length, u_L, is 4 in.

From Example 6.8,

$S_{rc} = 73.79$

$S_{re13} = 10.16$

Required:

The buckling load and mode of failure

Solution:

The slenderness ratio is given by Eq. (6.12):

$$S_{re12} = \frac{4U_L}{\left(D_p^2 + D_i^2\right)^{\frac{1}{2}}}$$

$$S_{re12} = \frac{4(4)}{(1.315^2 + 1.049^2)^{\frac{1}{2}}}$$

$$S_{re12} = \mathbf{9.51}$$

Since $S_{re12} < s_{re13} < S_{rc}$, the buckling mode is local inelastic.

The buckling load is given by Eq. (6.14):

$$P_{bkl} = F_y\left(D_p^2 - D_i^2\right)\left(\frac{0.7854S_{cr}^2 - 0.3927S_{re}^2}{S_{cr}^2}\right)$$

$$P_{bkl} = 105{,}000\left(1.315^2 - 1.049^2\right) \times \left(\frac{0.7854(73.79^2) - 0.3927(10.16^2)}{73.79^2}\right)$$

$$P_{bkl} = \mathbf{51{,}366}\,\mathrm{lb}_f$$

SPECIAL BUCKLING CONSIDERATIONS: VARIABLE DIAMETERS

In oil-field snubbing operations, the most frequently encountered problems involve long-column buckling. In these situations, the classical Euler solution is applicable. There are several solutions for the Euler equations depending on the end conditions. The classical approach assumes that the ends are pinned and free to rotate without any restriction due to friction. If the ends are fixed and cannot move, the critical load will be approximately four times that calculated using pinned ends. With one end fixed and the other pinned, the critical load will be approximately twice that determined with pinned ends. If one end is fixed and the other end is completely free to move, the critical load will be one-half of that calculated assuming pinned ends. For oil-field operations, the assumption of pinned ends is reasonable for most operations. However, field personnel should be aware of the assumptions made and remain alert for changes in the end conditions that could significantly reduce the critical load. *It must be remembered that once the critical load for a column is exceeded, failure is imminent and catastrophic.* The classical Euler equation for pinned ends is given as Eq. (6.16):

$$P_{cr} = \frac{\pi^2 EI}{L^2} \tag{6.16}$$

where

P_{cr} = critical buckling load, lb_f

E = Young's modulus, $30(10)^6$

I = moment of inertia, $\frac{\pi}{64}\left(D_o^4 - D_i^4\right)$

D_o = outside diameter, in.

D_i = inside diameter, in.

L = column length, in.

The previous discussion involved only loading of columns of constant dimensions. The problems, which arise when different diameters are involved, have not been addressed in oil-field operations. The exact solution of the differential equations is very complicated. Timoshenko [1] described a numerical solution. Only the methodology will be presented. For the theoretical aspects, please refer to the reference.

Consider a symmetrical beam as shown in Fig. 6.17. Assume a series of beams are to be snubbed into the hole. To determine the critical buckling load, it is assumed that the deflection of the beam can be described by a sine curve. The critical buckling load is determined pursuant to the methodology presented as Table 6.2.

Consider Example 6.10:

Example 6.10

A series of 4 in OD blast joints are to be included in a string of $2\frac{7}{8}$ in tubing and snubbed into the hole. The wellhead pressure is 7500 psi. Using the results developed in Table 6.2 and the following, determine a safe snubbing procedure.

Example 6.10—cont'd

Given:

Tubing dimensions:

OD = 2.875 in

ID = 2.323 in

Moment of inertia = 1.924 in^4

Cross-sectional area = 6.492 $in.^2$

Blast joint dimensions:

OD = 4.000 in

ID = 3.548 in

Moment of inertia = 4.788 in^4

Cross-sectional area = 12.566 $in.^2$

Young's modulus = 30,000,000

Unsupported stroke length = 10 ft

Ram friction = 10,000 lb_f

Solution:

$$\text{Snubbing force on } 2\frac{7}{8}\text{-in., } F_{snmx} = F_{wp} + F_f = (7500 \times 6.492) + 10,000$$
$$= 58,690\,\mathrm{lb}_f$$

$$\text{Snubbing force on 4-in., } F_{snmx} = F_{wp} + F_f = (7500 \times 12.566) + 10,000$$
$$= 104,245\,\mathrm{lb}_f$$

$$\text{Critical load, } P_{cr} = 8.52 \times \frac{EI_2}{L^2}$$
$$= 8.52 \times \frac{(30,000,000 \times 4.788)}{(10 \times 12)^2}$$
$$= 84,987\,\mathrm{lb}_f$$

As a check on the critical load determined by numerical analysis in Table 6.2, the value determined should be between those obtained using the classical Euler equation (6.16) to calculate the critical load for each member:

$$\text{Critical load for } 2\frac{7}{8}\text{-in.} = \frac{\pi^2 EI}{L^2} = \frac{3.14^2 \times 30,000,000 \times 1.924}{(10 \times 12)^2}$$
$$= 39,521\,\mathrm{lb}_f$$

and

$$\text{Critical load for 4-in.} = \frac{\pi^2 EI}{L^2} = \frac{3.14^2 \times 30,000,000 \times 4.788}{(10 \times 12)^2}$$
$$= 98,350\,\mathrm{lb}_f$$

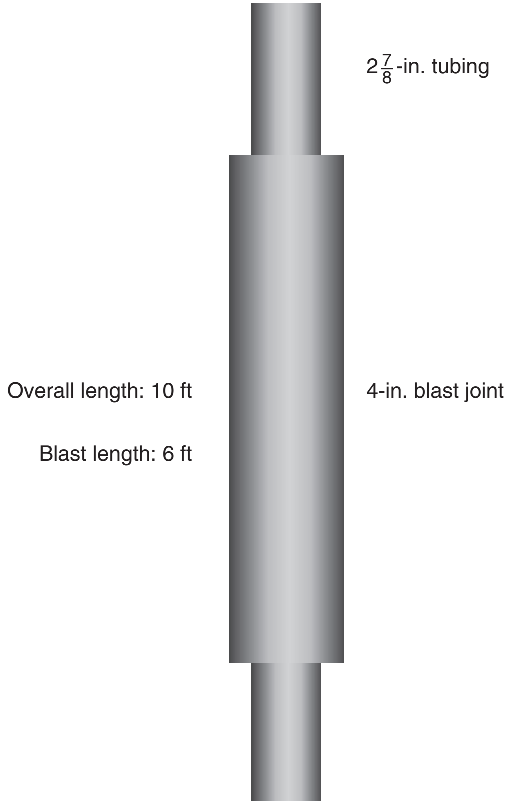


Fig. 6.17 Symmetrical beam.

Therefore, the numerical solution is between the Euler solutions and is reasonable. These calculations indicate that the assembly can be safely snubbed into the hole only if the snubbing rams are closed on the $2\frac{7}{8}$ and not on the 4 in. If the snubbing rams must be closed on the 4 in due to spacing problems, the wellhead pressure must be lowered or the stroke length reduced. If the stroke length cannot be reduced due to spacing problems, the only solution is to reduce the wellhead pressure.

FIRE FIGHTING AND CAPPING

Oil well firefighting is as much an art as a science. Firefighters from the United States are heavily influenced by the tradition and practices developed by Myron Kinley, the father of oil well firefighters. Those from outside the United States follow the same general procedure, which is to remove the

Table 6.2 Determining critical load for beams with varying cross sections

Column number	0	1	2	3	4	5	6	7	8	9	10		
Station number	0	1	2	3	4	5	6	7	8	9	10		
Y_1	0	31	59	81	95	100	95	81	59	31	0	632	Delta 1/100
M_1/EI	0.00	77.50	147.50	81.00	95.00	100.00	95.00	81.00	59.00	77.50	0.00		PDelta 1/100E12
			59.00						147.50				
R		7.69	9.59	8.03	9.43	9.92	9.43	8.03	9.59	7.69	0.00		
Average slope	39.69	32.01	22.42	14.38	4.96	0.00	4.96	14.38	22.42	32.01	39.69		
Y_2	0.00	3.97	7.17	9.41	10.85	11.35	10.85	9.41	7.17	3.97	0.00	74.15	
Y_1/Y_2		7.81	8.23	8.61	8.76	8.81	8.76	8.61	8.23	7.81			
Y_{lavg}/Y_{2avg}	8.52												

Therefore, $P_{cr} = 8.52 \times EI_2/l^2$.
Assume, $I_1 = 0.4I_2$.

$Y_1 = 100 \times$ sine (180 × station number/number of stations)
$f = M_1/EI = Y_1/.4$ (for members with I_1, geometry) $= Y_1$ (for members with I_2 geometry)
$R_n = (1/\text{number of stations}) \times (f_{n-1} + 10f_n + f_{n+1})/12 -$ for constant geometry
$R_n = (1/\text{number of stations}) \times (7f_n + 6f_{n-1} - f_{n-2})/24 + (1/\text{number of stations})$
$\times (7f_n + 6f_{n+1} - f_{n+2})/24$ for changing geometry
For column 3; $R_3 = 0.1 \times (7 \times 147.5 + 6 \times 77.6 - 0)/24 + 0.1$
$\times (7 \times 59 + 6 \times 81 - 95)/24$

Continued

Table 6.2 Determining critical load for beams with varying cross sections—cont'd

Column number	0	1	2	3	4	5	6	7	8	9	10
Average slope, $A_n = (R_0 + R_1 + R_2 + R_3 + R_4 + R_5/2) - R_n - R_{n-1} - R_{n-2} \ldots$											
For column 3; $A_3 = 39.69 - 8.03 - 9.59 - 7.69 = 14.38$											
$Y_{2n} = (1/\text{number of stations}) \times A_n$											
Pipe 1											
OD, in.	2.875										
ID, in.	2.323										
Moment of inertia, in.^{4}	1.92										
Cross-sectional area, in.^{2}	6.49										
Pipe 2											
OD, in.	4										
ID, in.	3.548										
Moment of inertia, in.^{4}	4.79										
Cross-sectional area, in.^{2}	12.57										
I_1/I_2	0.40										
Young's modulus	30,000,000										
Length, ft	10										
Well pressure, psi	7500										
Ram friction, lb_f	10,000										
Snub force, pipe 1, lb_f	58,689										
Snub force, pipe 2, lb_f	104,248										
Critical load, lb_f	85,017										
Euler critical load—$2\frac{7}{8}$	39,565.49										
Euler critical load—4 in.	98,443.52										

remnants of the rig or other equipment until the fire is burning through one orifice straight into the air.

FIRE FIGHTING

The equipment used to remove the rig or other equipment from the fire may differ slightly. The firefighters trained in the tradition of Myron Kinley rely heavily on the Athey wagon such as illustrated in Figs. 6.18 and 6.19. The Athey wagon was originally developed for the pipeline industry. As shown, it is a boom on a track. The Athey wagon tongue is attached to a dozer with a winch (Fig. 6.20). The Athey wagon is maneuvered into position for a particular operation utilizing the dozer. The Athey wagon boom is about 60 ft long and is raised and lowered by the winch on the dozer, and the end of the Athey wagon (Fig. 6.19) may be changed to adapt to different requirements. For example, the hook shown on the end of the Athey wagon in Fig. 6.19 is routinely used to drag pieces of a melted drilling rig from the fire around the well.

Protecting men and equipment from the heat of an oil well fire is difficult. As in fighting any fire, water is used to cool the fire and provide protection from the heat. Oil well firefighters from the United States use skid-mounted centrifugal pumps such as the one illustrated in Fig. 6.21. These pumps are capable of pumping as much as of 4800 gal

Fig. 6.18 Athey wagon from dozer end.

Fig. 6.19 Athey wagon from end opposite dozer.

Fig. 6.20 Athey wagon with dozer attached.

(more than 100 bbl)/min. At this rate, water supply becomes a critical factor. In order to support a full day of operations, pits are constructed with a typical capacity of approximately 25,000 bbl. The pumps and monitors (see Fig. 6.23) are often connected by hard lines or a combination of hard lines and fire hoses. Rig up can be time-consuming.

Fig. 6.21 Firefighting pump.

Safety Boss, the Canadian oil well firefighting company, has perfected pumping equipment based on specially designed and modified fire trucks. Their fire trucks (Fig. 6.22) are equipped with pumps capable of delivering water at a maximum rate of 2100 gal (50 bbl)/min. In addition, these trucks

Fig. 6.22 Oil well firefighting equipment using a modified fire truck.

are capable of delivering a variety of fire-retardant chemicals in addition to or along with the water. Utilizing this equipment, water requirements can be reduced to an available capacity of approximately 3000–4000 bbl. All connections between the fire trucks, the tanks, and the monitors are made with fire hoses, which reduces rig-up time.

Due to their mobility, fire-truck response time is significantly reduced in a localized environment. In Kuwait, for example, this mobile equipment was to the firefighting effort, as the cavalry was to the army. That is, in most cases, utilizing mobile equipment, the fire would be out and the well capped before the skid-mounted equipment could be moved and rigged up. The mobility factor contributed significantly to the fact that the Canadian team fixed approximately 50% more wells than the nearest other team. In addition, in Kuwait, the mobile firefighting equipment did not require as much support as the skidded equipment.

All equipment such as dozers, track hoes, and front-end loaders and their operators are required to work near the fire and must be protected from the heat. The hydraulic systems for the equipment are protected by a covering with reflective shielding and insulating material. The personnel are protected with heat shields constructed from reflective metal. Reflective protection for a water monitor is shown in Fig. 6.23. In addition, heat shields and staging houses constructed with reflective metal offer personnel relief from the heat in the proximity of the fire.

Fig. 6.23 Monitor house with reflective protection.

Most organizations require that all personnel wear long-sleeved coveralls made of fire-retardant materials. Around an oil well fire, ordinary cotton coveralls are a hazard. Some utilize more conventional firefighting protective clothing such as the bunker suit commonly used by local fire departments. A fewer number use the perimeter suits, which can be worn into a fire.

In a typical firefighting operation, the crew will approach the fire from the same direction as the prevailing wind. The pumps will be spotted approximately 300 ft from the fire. Water will provide protection as dozers or front-end loaders are used to move the monitor houses toward the fire. Once the monitor houses are within approximately 50 ft of the burning well, other equipment, such as the Athey wagon, is brought into the proximity of the well to remove remnants of the rig and potential reignition sources. Work continues until the fire is burning straight in the air. Once the fire is burning straight into the air, the fire can be extinguished and the well capped. If conditions require, the well can be capped with the fire burning.

EXTINGUISHING THE FIRE

In most instances, the fire is extinguished prior to the capping operation. However, in some cases, conditions dictate that the fire continue to burn until after the capping operation. For example, environmental concerns may dictate that the well be permitted to burn until the wellbore fluids can be contained or the flow stopped. Further, in some areas, the regulatory agency requires that sour-gas wells be ignited and that control operations be conducted with the well burning.

There are several alternatives commonly utilized to extinguish an oil well fire. Explosives are the most famous and glamorous technique used. Myron Kinley's father, Karl, was the first to extinguish an oil well fire with explosives. In 1913, Mr. Kinley walked up to a well fire near Taft, California, dropped a dynamite bomb onto the wellhead, and ran [2]. The subsequent explosion extinguished a fire that had been burning for several months.

Today, generally between 100 and 1000 lb of dynamite, with the lower being more common, are packed into a 55 gal drum. Fire-retarding powders are included in the drum, which is subsequently wrapped with insulating material. The loaded drum is attached to the end of an Athey wagon. The water monitors are concentrated on the drum as the Athey wagon is backed into the fire. With the drum positioned at the base of the fire, the driver and the shooter take cover in the blade of the dozer, and the charge is detonated. The explosion momentarily deprives the fire of oxygen, and as a result, the fire is extinguished. The water monitors are then concentrated on the wellhead in an effort to prevent reignition.

In Kuwait, the fires were usually extinguished with water. Several monitors were concentrated on the base of the fire. Usually in a matter of minutes, the fire was cooled below the ignition point.

Safety Boss, the company of Canadian oil well firefighters, has relied upon and perfected the use of fire-retardant chemicals and powders. Custom-designed and custom-constructed fire-extinguishing equipment is used to spray these chemicals and powders directly on the fire. These techniques have proved to be very reliable. In Canada, sour-gas fires often have to be extinguished and reignited several times during the course of a day—a process that would not be possible using explosives or water monitors.

Countries associated with the former Soviet Union utilized mounted jet engines to literally blow the fire out. Most often, the fire-extinguishing technique included a MIG engine mounted on a flatbed trailer. Water would be sprayed on the fire and the engine engaged. Using only one jet engine, the time to extinguish the fire would be extended and often exceeded an hour. In the opinion of this writer, one jet engine would not extinguish a large oil well fire. The most impressive wind machine was designed and utilized in Kuwait by the Hungarian firefighters (see Fig. 11.19). The Hungarian "Big Wind" used two MIG engines on a tank track. The crew had the capability to inject water- and fire-retardant chemicals into the flow stream. The "Big Wind" quickly extinguished the fire in every instance in Kuwait. However, it was never used in Kuwait on one of the bigger fires.

CAPPING THE WELL

Once the fire is out, the capping operation begins. The well is capped on an available flange or on bare pipe, utilizing a capping stack. The capping stack is composed of one or more blind rams on top followed by a flow cross with diverter lines. The configuration of the bottom of the capping stack depends upon the configuration of the remaining well components.

If a flange is available, the bottom of the capping stack below the flow cross will be an adapter flange. A flanged capping stack is illustrated in Fig. 6.24. If bare pipe is exposed, the bottom of the capping stack below the flow cross will be composed of an inverted pipe ram followed by a slip ram. A capping stack with an inverted pipe ram and a slip ram is depicted in

Fig. 6.24 Capping stack with flange on bottom.

Fig. 6.25 Capping stack with inverted ram and slip ram on bottom.

Fig. 6.25. The capping stacks are placed on the well with a crane or an Athey wagon.

In the case of exposed pipe, an alternative to the inverted pipe ram and slip ram is to install a casing flange. As illustrated in Fig. 6.26, an ordinary casing flange is slipped over the exposed tubular. A crane or hydraulic jacks, supported by a wooden foundation composed of short lengths 4×4's, are

Fig. 6.26 Casing head slipped over casing and set with hydraulic jacks.

used to set the slips on the casing head. Concrete is then poured around the jacks and foundation to the bottom of the casing head. Once the casing head is set, the excess casing is cut off using a pneumatic cutter. A capping stack can then be nippled up on the casing flange.

Another common technique used on bare pipe is to install a weld-on flange on the bottom of the capping stack. The stack is then lowered over and onto the bare pipe. If the fire has been extinguished, the stack is lowered with a crane. If the fire has not been extinguished, the stack is installed with an Athey wagon. With the stack in place, the slip-on flange is welded to the bare pipe. The flow from the well is far enough above the welding operation to prevent reignition.

In all instances, it is important that the capping stack be larger than the wellhead. The larger stack will produce a chimney effect at the capping point. A smaller stack would result in back pressure and flow at the capping point.

In the worst cases, guides are required to bring the capping stack over the flow. If the flow is strong, the stack has to be snubbed onto the well (Fig. 6.27). There is almost always a period of time during capping when visual contact is impossible (Fig. 6.28).

Once the stack is landed, the vent lines are connected, and the blind ram is closed, causing the flow to be vented to a pit that should be at least 300 ft from the wellhead. With the well vented, the capping operation is complete, and the control and killing operation commences.

Fig. 6.27 Capping stack with guides.

Fig. 6.28 Vision impaired while installing capping stack.

FREEZING

Freezing is a very useful tool in well control. Invariably, the top ball valve in the drill string will be too small to permit the running of a plug. In order to remove the valve with pressure on the drill pipe, the drill pipe would have to be frozen. A wooden box is constructed around the area to be frozen. Then, a very viscous mixture of bentonite and water is pumped into the drill pipe and spotted across the area to be frozen.

Next, the freeze box is filled with dry ice (solid carbon dioxide). Nitrogen should never be used to freeze because it is too cold. The steel becomes very brittle and may shatter upon impact. Several hours may be required to obtain a good plug. The rule of thumb is 1 h for each in. in diameter to be frozen. Finally, the pressure is bled from above the faulty valve; it is removed and replaced, and the plug is permitted to thaw. Almost everything imaginable has been frozen, including valves and blowout preventers.

HOT TAPPING

Hot tapping is another useful tool in well control. Hot tapping consists of simply flanging or saddling to the object to be tapped and drilling into the pressure. Almost anything can be hot tapped. For example, an inoperable valve can be hot tapped, or a plugged joint of drill pipe can be hot tapped, and the pressure safely bled to the atmosphere. In other instances, a joint of drill pipe has been hot tapped and kill fluid injected through the tap.

JET CUTTING

Abrasive-jet-cutting technology has been used in well control and other industries for many years. However, since the extensive use of abrasive jet cutting during the Al-Awda project (Kuwait), service providers for the well control industry have designed and utilized much more sophisticated equipment.

An abrasive jet cutter used in well control is shown in Fig. 6.29. These cutters attach to the end of the Athey wagon. The jet nozzle is positioned adjacent to the object to be severed using the Athey wagon attached to a dozer. Frac sand at a concentration of about 2 ppg is transported by either water or a mixture of bentonite and water. The mixture is pumped through nozzles at a rate of approximately 2 bpm and a pressure between 5000 psi and 8000 psi. The nozzle size normally used is approximately $\frac{3}{16}$ in.

Just as often, a jet nozzle is attached to the end of a joint of the pipe, and the assembly is moved into position by a crane or track hoe. Cutting can be just as effective. The big advantage is mobility and availability. It is not necessary to import a large piece of equipment. The nozzles can be transported in a briefcase, and the remaining required equipment is readily available.

Fig. 6.29 Jet cutting *(Courtesy of BJ Services.)*

This technology has been used to cut drill pipe, drill collars, casing strings, and wellheads. The time required to make the cut depends on the object to be cut and the operating conditions. A single piece of pipe can be cut in a few minutes. Abrasive jet cutting is preferable to other methods in most instances.

REFERENCES

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[2] Kinley JD, Whitworth EA. Call Kinley: adventures of an oil well fire fighter. Tulsa, OK: Cock a Hoop Publishers; 1996. p. 18.

CHAPTER SEVEN

How to Drill a Relief Well

12 May

0300 hours—noticed an increase in torque. Rate of penetration dropped.

0430 hours—Tripped out of hole. Inspected bit. Appears to have run on metal. Company representative concluded it was normal formation wear. MWD had magnetic interference. Gyro surveys indicate 10 ft between wells at this depth.

0600 hours—Trip in hole and continue drilling. Rotated about 45 min with no progress. Mud room called to say that there was too much mud coming over the shakers. Production called to say the adjacent well was losing pressure. Production well intercepted. Blow out.

OVERVIEW

There is nothing magic about a relief well. Any drilling engineer with a minimal amount of experience can design a relief well. There are a few peculiarities to consider and keep in mind, but the drilling considerations are fairly routine. In most instances, it is just like the other wells drilled around it—just another hole in the ground. Generally, the casing program for the relief well will be the same as the casing program for the blowout well. In the days when directional drilling was a novelty in land-based operations, there were challenges. Today, with most onshore wells being horizontal, directional drilling is the norm, and the technology is advanced.

Controlling and killing the blowout once the relief well has been drilled is a separate issue, but the two are intertwined. I will address those issues at the end of this writing. First, let us consider the drilling of the relief well itself.

Relief Well Categories

There are two categories of relief wells—*direct intercept relief wells* and *geometric relief wells*. The first relief wells were geometric relief wells. The geometric

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relief well is one whose wellbore is close enough to establish communication between the relief well and the blowout well. In horizontal well blowouts or blowouts where no tubulars are in the blowout wellbore, a geometric relief well will most likely be the only alternative. As the name implies, the direct intercept relief well is one that literally intercepts or drills into the blowout wellbore. The direct intercept relief well requires a metallic target at the point of the planned intercept.

The direct intercept relief well is drilled in the vast majority of instances. The direct intercept relief well, which will be discussed first, is a relief well that literally drills into the blowout wellbore. Obviously, in order to intercept the blowout wellbore somewhere beneath the surface, the location of the blowout wellbore relative to the relief well has to be determinable. Today, the relative position of the two wellbores is defined by wellbore proximity logging. All wellbore proximity logging is based on analyzing a magnetic anomaly caused by the presence of drill pipe, casing or other tubulars in or very near to the zone from which the well is blowing out. Since the advent of wellbore proximity logging, the direct intercept relief well has been the preferred approach because the control and kill operation is greatly simplified and is a certainty utilizing modern analytic techniques.

PLANNING

How Many Relief Wells Are Required?

I've never seen an instance where more than one direct intercept relief well was required to kill a blowout. However, in some instances, more than one relief well has been started for various reasons. In some cases, the operator wants to be certain that everything possible is being done to bring the blowout under control. In other cases, the operator wanted to have a backup in the event of problems with the primary relief well. These are political reasons and not technical reasons.

In some operations, two relief wells were started at the same time for political reasons. Invariably, one had to be designated as the primary relief well. So long as the operation at the primary relief well was going as planned, operations at the second relief well had to be suspended so as not to interfere with the efforts at the primary relief well. Therefore, typically at some intermediate casing point, the operation at the second relief well was suspended, and the rig was idle, while operations continued at the primary relief well. This is usually frustrating for operators and drilling crews alike.

Since the proximity logs depend on magnetic anomalies in the blowout wellbore, only one relief well should be drilling in the interval where proximity logging is to be or is being done. The last thing that is needed is for there to be another magnetic anomaly in the vicinity of the blowout wellbore to confuse the analyses.

Where to Spot the Relief Well?

There are several considerations with regard to where to put the relief well relative to the blowout. If there is an underground blowout in progress, the fracture orientation at the point of the underground blowout must be determined and avoided. For example, at the TXO Marshall blowout a long time ago, there was a strong underground blowout. Several relief wells were started, but none could drill beyond the point of the underground flow. At the depth of the underground blowout, they would encounter abnormal pressure (generally 1 psi/ft) and get blown off location. A study was made of the fracture orientation, and a relief well location was selected perpendicular to the fracture plane. That relief well had no difficulty drilling through the interval of the underground blowout.

Wind direction can be a factor. If there is a big fire at the blowout, the heat can be intense downwind from the blowout, and a location upwind might be better. Offshore, currents can be a consideration if there are hydrocarbons on the water. It is not desirable to rig up where there might be fire on the water.

If there is another well in the immediate vicinity of the blowout, it must be considered as it can confuse the interpretation of the data obtained from the proximity log. In that case, the relief well plan must include a strategy to eliminate any potential confusion.

If the blowout is in a hard rock area, drilling against the regional drift tendency can be time-consuming at best and impossible at worst. At the Apache Key blowout in 1981, in the Texas Panhandle, the initial relief well could make little or no progress drilling toward the blowout. A second relief well was started at a surface location designed to take advantage of the regional drift tendency. The second relief well progressed without difficulty and became the primary relief well.

Many operators seem to be afraid to spot the surface location of the relief well very close to the surface of the blowout. It seems to be forgotten that the relief well must drill over to the blowout and the further apart the surface locations are, the more complicated the relief well will have to be, and the longer it will take to drill. All things being equal, spot the surface location as close as possible to the surface location of the blowout. It will make everything else very much easier.

One of the most important things to know is the surface location of the relief well relative to the surface location of the blowout. Remember that if measurement is inaccurately known, all of the comparisons between surveys in the two wells will be inaccurate. In my experience, the relief well location cannot be identified by Global Positioning System (GPS) coordinates. It is highly recommended that civil surveyors be used to physically survey the two locations and prepare a civil engineering plat. This reference is accurate and reliable.

Where Is It?

Where is the bottom-hole location of the blowout relative to the surface location? Wells intended to be vertical will naturally drift as they are drilled. The bottom-hole location at total depth can be about anywhere. In the past, most wells that were drilled were only surveyed for deviation, and directional surveys were rare. To make matters worse, in many instances, the deviation surveys were run in the doghouse.

At the Apache Key relief well, only deviation surveys were available for the planning phase. With the blowout zone at 16,400 ft, the cone of uncertainty at 14,000 ft was 514 ft in diameter, and it was estimated that as many as five passes through the cone of uncertainty might be required to locate the blowout wellbore. To narrow things down, a study of the regional drift tendencies in 25 surrounding wells was made, and the uncertainty was reduced to an area that was 50 ft wide, 85 ft long, and 90 ft northwest from the surface location of the blowout. The relief well was steered to that area, and the blowout wellbore was found on the first attempt.

In another instance, the cone of uncertainty was determined and drilled without finding the target. The well had to be plugged back, found higher, and followed to TD for the intercept. In that case, the deviation surveys were obviously run in the doghouse as the bottom-hole location was nowhere near where it was supposed to be.

Most wells drilled in recent years have directional surveys, and the quality of that data is excellent, in my experience. I personally have complete confidence in modern directional surveys and will not hesitate to develop the relief well plan based on the directional data from the blowout well. In cases like that, I am confident that when the projected target based on the directional surveys is within the range of the proximity logs, it will be detected by the proximity log.

Where to Intercept the Blowout?

Another consideration in relief well operations is where to intercept the blowout wellbore. All things being equal, the best intercept is immediately above the blowout zone. In any event, the pressures anticipated in the kill operation must insure that the blowout is killed and cemented and not fractured at the last casing shoe in the relief well. The system is just one big U-tube, and the weakest point in the U-tube must be the fracture pressure in the blowout zone.

What Is the Target?

As previously mentioned, in order to intercept the blowout wellbore with the relief well, there must be tubulars in the blowout wellbore. The best case is where there is casing all the way to the blowout zone. In this instance, the target will be the casing in the blowout well.

If the blowout was a drilling well, the target has to be the drill pipe provided that it is near or through the blowout zone. If the flow is through the drill string, the planned intercept should be at the top of the blowout zone or nearer the end of the drill string, whichever is shallower.

In many instances, the flow path is a mystery. One thing to keep in mind when attempting to determine the flow path to be intercepted is that it is virtually impossible for a blowout to continue for very long through open hole, particularly in young rocks such as those found offshore and in coastal areas. The time required to bridge in younger rocks can be a matter of hours. It can continue longer through open hole in older rocks, but then, it is usually a matter of days. If the blowout continues, look for a path that is somehow through the tubulars. If the casing or drill pipe is parted, it will impact the interpretation of the proximity logs. A complete wellbore schematic is essential.

At the Amerada Hess MillVid 3 well near Beaumont, Texas, the intermediate pipe was set at 8600 ft, and total depth was below 13,000 ft. The bit was believed to be about 100 ft off bottom when the pipe became stuck. While working the pipe in an attempt to free it, the drill pipe parted just below the intermediate casing. The well continued a strong flow during the relief well operations. It was later learned that the well was flowing up through the parted drill string and into the formation at the intermediate casing shoe. The well was intercepted just above the bit and drilled alongside the drill collars to the bit. Once the bit was reached, the well died almost instantly.

How to Find the Blowout Wellbore

In order to achieve an intercept, wellbore proximity logging is required. Proximity logs were introduced in the 1970s and perfected in the 1980s. Little has changed since the early 1980s. Proximity logs are based on the detection and analysis of magnetic anomalies caused by the presence of metallic objects in the blowout wellbore.

The first proximity logs were based on what is referred to as passive magnetics. Specifically, sensitive magnetometers are used to detect and analyze anomalies in the earth's magnetic field caused by the presence of tubulars in the blowout wellbore. Passive magnetic proximity logging was first offered by Tensor Corp under the trade name Magrange. Over the years, there have been other companies that offered the passive magnetic technology, but to the best of my knowledge at this writing, none of those are still in business.

Passive magnetic services are offered today by some service companies as a by-product of their Measurement While Drilling (MWD) services. In these cases, the magnetic interference in the MWD data is analyzed to determine the distance and direction of the magnetic anomaly. The depth of investigation for passive magnetic technology is roughly 30 ft. Or the relief well must be roughly 30 ft from the blowout well to be detected utilizing passive magnetic technology.

The other proximity logging technology is referred to as active magnetics. The only active magnetic technology was developed by Vector Magnetics in Ithaca, New York, in the early 1980s, sold to Halliburton in 2014 and marketed today under the trade name Wellspot.

The approach in active magnetics is quite simple and straightforward. As illustrated in Fig. 7.1, an electrode is run on a conventional electric line 300 ft above a tool consisting of four magnetometers. Two AC magnetometers respond to the two components of an AC magnetic field perpendicular to the axis of the tool, and two fluxgate magnetometers measure the two components of the earth's magnetic field perpendicular to the tool axis. The fluxgates act as a magnetic compass so that the tool's orientation can be determined.

Between the tool and the wire line from the logging truck, there is an insulating bridle approximately 400 ft long. On this bridle cable 300 ft above the tool, an electrode emits AC electric current into the formations. In the absence of a nearby ferrous material, such as the casing in the blowout, the current flows symmetrically into the ground and dissipates. In the presence of a ferromagnetic body, such as the casing or drill string in the blowout, the flow of electric current is short-circuited, creating a magnetic field. The intensity and direction of the magnetic field are measured at the

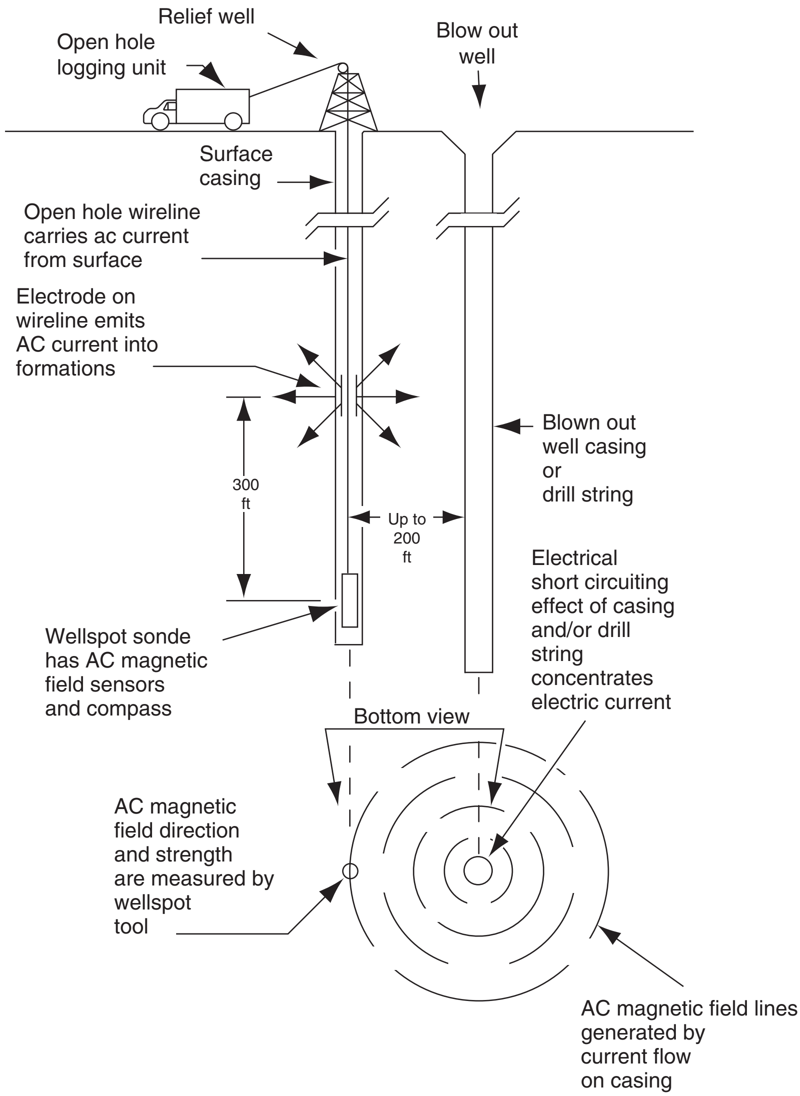

Fig. 7.1 Wellspot operations.

tool. The various parameters are analyzed using a general routine and theoretically straightforward mathematical analysis. Depending on the conductivity of the formations in the wellbore relative to the conductivity of the ferromagnetic body, the method can detect the blowout from the relief well at distances greater than 200 ft. However, under most conditions, the detection range is 100 ft or less.

For reasons that will be discussed, the active magnetic technology is superior in virtually every respect in my opinion and experience. Passive magnetics has been resurrected in recent years and will be discussed later in this chapter. An in-depth history and comparison of these two techniques are also presented later in this chapter.

The shortcomings of active magnetics are few but must be considered. Rig time spent logging can be significant. The proximity logging tools are run on a conventional wire line that is furnished by a third-party well-logging company. Therefore, the drill string must be pulled, and the logging tool run. In deep wells, the trip time can be significant. And in the latter stages of the operation, the proximity log might be run every few feet, which results in a considerable amount of logging time. Compounding the problem, the tool is small and light and can sometimes be difficult to run to bottom, particularly after many directional changes.

In response to that problem, Vector Magnetics developed the Wellspot at Bit (WSAB) tool, which can be used to take measurements without tripping and running the logging tool in the open hole. However, the magnetic intensity recorded by the WSAB tool is roughly one-tenth of that recorded by the open hole tools. In one recent operation, the WSAB technique proved inadequate, and open hole logs had to be run.

The applicable range of the active magnetic logging tools is a function of the resistivity of the formations along with the magnetic characteristics of the tubulars in the blowout. The formation conductivity or resistivity has greater impact. The lower the resistivity of the formation, the better. Shale conducts electricity better than limestone. Therefore, a target is detectable in the former at greater distances. In one case, the formations were anhydrites, and the blowout could not be detected until the relief well was roughly 40 ft from the blowout. In another instance where the formations consisted largely of unconsolidated sand and mudstones, the blowout could be detected when it was roughly 150 ft from the relief well.

The geometry of the tubulars in the blowout well can complicate the analysis of the data and determination of the distance to the target. For the purposes of analyses, the geometry of the tubulars must be modeled. Often, the blowout has been through a very destructive series of events, and the exact condition of the tubulars may not be known.

At the Niko Chattak blowout in Bangladesh, only a few hundred feet of surface pipe was set; the bit was 1100 ft from bottom and 300 ft above the blowout zone. The drill pipe was in the slips when the well blew out.

The rig disappeared into a crater. Did the drill pipe remain in the slips or part and fall to bottom? Was the bit still 1100 ft off bottom or somewhere in between? Where was the surface pipe? It was anyone's guess, and everyone on location had a different guess that was rational. When the target was identified by proximity logging, the assumption that the drill string was still in the slips puts the blowout 30 ft further away from the blowout than the assumption that the drill string had fallen to bottom. In the final analysis, drill string was found across the blowout zone. Everything else remained a mystery.

The direction to the target is very accurate, in my experience, from the time that the target is first detected. However, the distance as determined by interpretation of direct measurements is not very accurate when far away but improves as the relief well nears the target. Under the best scenario, the distance between the relief well and the blowout is difficult to accurately determine in the early stages.

For example, in one operation, the direction indicated in the early runs proved to be completely accurate. In the final analysis of the data, the relief well actually began to detect the blowout wellbore when it was 153 ft from the blowout. The data from the first two runs indicated that the relief well was approaching the blowout, but the intensity was insufficient to make a determination of distance. On the third run, the data were sufficient to make a call as to distance and direction. The distance between the relief well and the blowout was predicted to be 39 ft. When the intercept was finally made, it was determined that the actual distance when the third logging run was made was more on the order of 72 ft. On the fourth run, the prediction was that it was 33 ft between wellbores, and it was later determined that the actual distance was 48 ft. On the fifth run, the call was 20 ft, and the actual distance was determined to be 18 ft. Clearly, as the relief well approached the blowout well, the accuracy improved.

Vector Magnetics developed several different approaches to mitigate the problems encountered with determining the distance between the two wells. The best and most accurate is their gradient ranging tool. This tool has two magnetometers 1–2 in. apart in the x–y plane. These are used to measure differences due to the separation and directly determine the distance to the target. This tool very accurately determines distance when the distance is roughly 10 ft or less.

Vector realized that even very early determination of direction from the relief well to the blowout was accurate. In order to mitigate the early distance problem, they proposed to make a "pass by." The pass by simply means that they wanted to drill by the blowout well in order to make numerous directional determinations and triangulate the target. Distances determined in this manner are much more accurate and reliable. However, the relief well drilled past the blowout well and was going in the wrong direction. After the ranging data was gathered and the distance to target determined, the relief well would have to be plugged back. Then, redrilled toward the blowout for the intercept.

There are at least three things potentially problematic with this approach. One is that drilling past the blowout risks running into the blowout prematurely. That has happened in the past. Another is that drilling past the blowout risks running into the formation fracture pattern, and if there is an underground flow in progress, there is a risk of encountering that underground flow. In some instances, it has not been possible to continue when the relief well has encountered an underground flow from the blowout. The third is that a plug back will be required and that is always time-consuming at a time when time is of the essence.

An alternative to actually passing by the blowout wellbore is the "lazy pass by." The lazy pass by means that the relief well is directionally drilled to the left and right of the target by changing the azimuth. By changing the direction to the target, triangulation can be used to get a better approximation of the early distance. The lazy pass by has fewer potential complications than the pass by. But, in my experience, it always resulted in roughly twice as many ranging runs and much longer over all time required to bring the well under control.

I never found the early distance inaccuracies to be a problem. I preferred to assume the directional data from the blowout well were reliable and drill straight for the intercept point. The distance problems always solved themselves as we approached the blowout. In my opinion, the additional time required and problems associated with the pass by approaches were much more significant to the operation. And when the blowout was within the range of the gradient ranging tool, the distances were very accurate.

My recommended ranging strategy was basically this:

1. When the relief well reached the best estimate of the maximum possible detection distance, make the first ranging run to try to see the target.
2. If the target cannot be identified, drill ahead a short distance and range again.
3. When the target is identified, drill one-half of the remaining distance to the target and range again.
4. Adjust according to the new data, drill one-half of the remaining distance and range again.

5. In most instances, set casing immediately above the intercept point and roughly 2–5 ft from casing in the blowout well. If the target in the blowout well was only drill pipe, the protective casing might be set a little further than 2–5 ft away.
6. Drill out the intermediate casing and toward the casing in the target. Approach the target in the same direction the target is being drilled or drifting.
7. In the final approach to the target, an incidence angle of 1–3 degrees was perfect for the intercept and avoided the potential to bounce off or drill past the target.
8. Range as frequently as necessary to insure the intercept. Usually, two or three more ranging runs are required after setting the last string of casing. Passing the target and having to turn and drill back to the target takes considerable TVD and should be avoided.

Intercept Method

If the target was casing and after the bit has contacted the casing, a mill such as pictured in Fig. 7.2 should be run. It is usually easy to mill into the casing and establish communication. Generally, the pressure differential across the casing is substantial as the relief well has full hydrostatic, while the blowout well only has flowing bottom-hole pressure. I'm sure that in most instances, the mill removes just enough steel to cause the casing to collapse. I have never known an instance where the flow between wells was restricted.

Fig. 7.2 Typical intercept mill.

As shown, the intercept mill is concave and has flow courses up the side. The side of the mill is covered with tungsten carbide so as to cut into the casing in the target. Often communication can be established with one mill.

Some have recommended to drill alongside the blowout and then run perforating guns in order to communicate with the blowout. *This approach is neither necessary nor recommended*. In the first place, it is simply too easy to drill into the blowout wellbore. After all, that is what the proximity logging offers. In the second place, communicating with perforating guns has its own problems. If a three-dimensional drawing is made up of two wellbores and the orientation of the perforating guns is added, it becomes apparent that it is easy to miss the blowout.

Generally, the casing program for the relief well will be the same as the casing program for the target well. Prior to the intercept, the last liner or string of casing is usually 2–5 ft from the target, aligned behind the target and in the same direction but with an incident angle of 2–4 degrees. The incidence angle is important because it is much easier to steer the relief well using tool high side for direction to the target. After drilling out of the last casing string, a final ranging run is usually made prior to the intercept.

All things being equal, I like to intercept the blowout wellbore immediately above the blowout zone or within a couple hundred feet of the top of the blowout zone. As in the Shell Cox, the intercept does not have to be near the blowout zone. It can be anywhere in the hole so long as the kill fluid can control the well without exceeding the fracture gradient at the intercept. Generally, the planned intercept point is beneath the last casing point and above the producing interval. Pore pressure and fracture gradients must be considered when selecting the intercept. The blowout zone must be the weakest zone open to the relief well because it is likely that a fracture gradient somewhere in the wellbore will be exceeded. And, it is best to break down the blowout zone than a casing shoe somewhere else in the open wellbore. One thing for certain, the well has to be dead for the fracture gradient in the blowout zone to be exceeded. In most instances, the intercept is planned to be in an impermeable formation very near to the top of the blowout zone. An intercept in the blowout zone is not generally encouraged.

It is better, in my opinion, to plan on breaking down and pumping into the blowout zone. One thing I have learned for sure is that a blowout zone can't blow and suck at the same time. Therefore, if the blowout zone has been broken down and is taking fluid, it must be dead. Generally, cement will follow the kill fluid. With the blowout formation broken down, it can be assured that cement has been pumped into the blowout formation, thus securing the well.

Losing circulation scares most drilling folks as they work all their professional lives trying to avoid lost circulation. But, in well control, lost circulation is good if returns are lost into the blowout zone. Some suggest that the best approach is to pump mud of a particular density at rates insufficient to fracture the formation. I think that it is stretching our abilities and a bit too cute, frankly. And if the intercept is very far above the blowout zone, the interval between the blowout zone and the intercept point cannot be secured with cement.

A TYPICAL RELIEF WELL OPERATION USING ACTIVE MAGNETICS

Recently, an operator was in the process of working over a well drilled in 1952 when it blew out. The well cratered with tubing in the derrick of the workover rig. The tubing in the derrick disappeared into the crater along with the wellhead. Surface intervention was not possible, and relief wells were planned.

This blowout was on the outskirts of Edmonton, Alberta. As with many wells in Canada, H_2S was a concern. The presence of houses in the immediate vicinity of the blowout made the H_2S of even greater concern.

The well was located in a developed area. As shown in Fig. 7.3, there were numerous wells in the surrounding area. But there was one well roughly 80 ft southwest from the blowout that posed a potential problem for magnetic proximity logging.

Total depth of the immediate offset well was 4111 ft. As shown in the wellbore schematic in Fig. 7.4, the total depth of the blowout well was 5095 ft. Perforations in the blowout well were from 4873 to 5089 ft. Therefore, with roughly 750 ft of blowout wellbore deeper than the offset, there was little room to confirm the location of the blowout wellbore prior to the intercept.

In this case, the surface location of the relief well was 486 ft away from the surface location of the blowout. The blowout well had 7 in. casing cemented at 4640 ft and a 5 in. liner cemented at 5094 ft. The blowout formation was a prolific vugular limestone.

The blowout resulted in a large well fire. However, the biggest problem was the vast quantity of water being produced along with oil and gas. Managing the water was a significant problem.

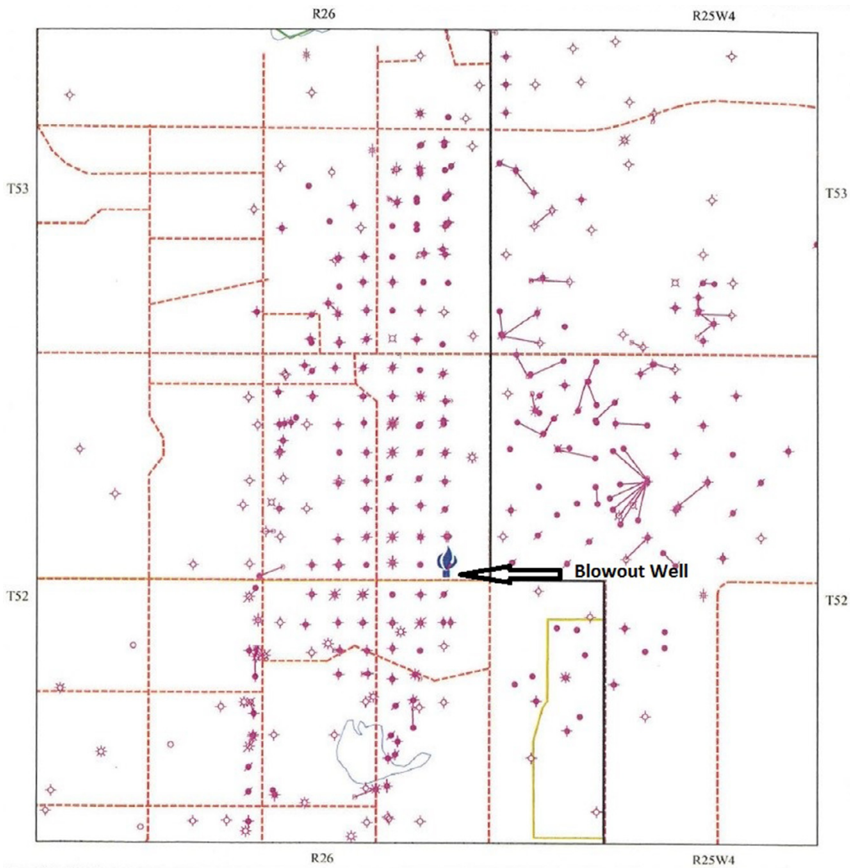

Fig. 7.3 Map showing location of blowout well.

Since it was drilled in the 1950s, there were only deviation surveys. The surveys indicated that the deviation never exceeded 1 degree. Analysis of the directional data from surrounding wells indicated that the blowout wellbore most likely drifted to the northwest from the surface location.

In this instance, the operator decided to start a second relief well at roughly the same time. The blowout was on the outskirts of a major city. The wind was blowing toward the city, and there was a severe water production problem. Time was of extreme essence, and the operator wanted a "Plan B" in the event the first relief well encountered operational problems.

There was another well immediately south of the blowout. Geography, wind direction, water hauling considerations, and housing prohibited spotting the relief well location north of the blowout. Therefore, in order to

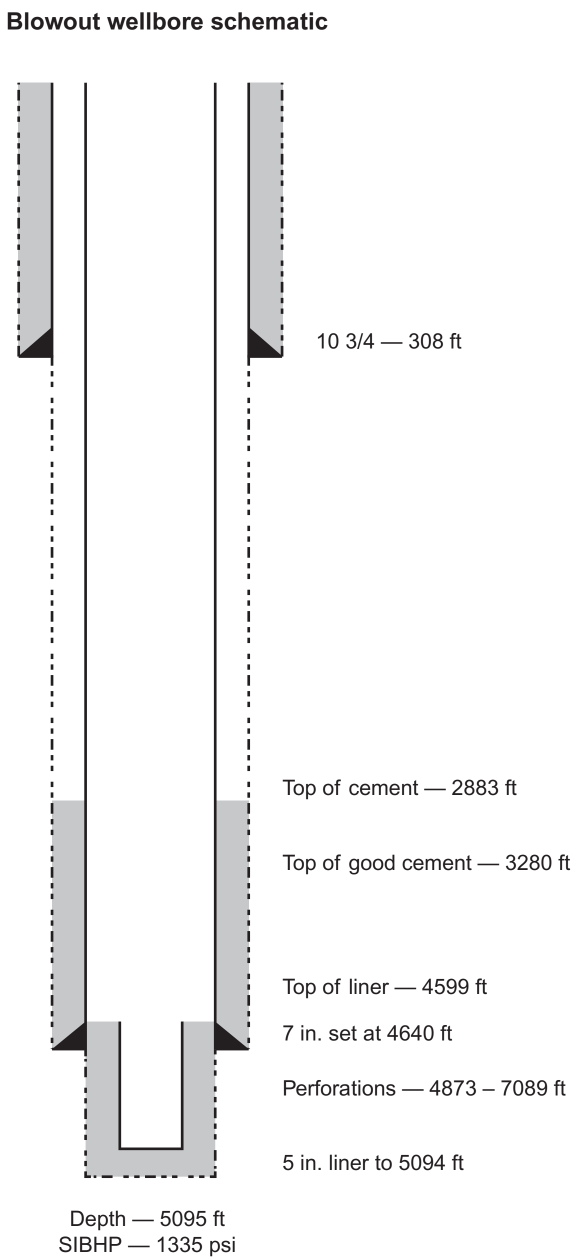

Fig. 7.4 Wellbore diagram of blowout well.

mitigate the potential for magnetic interference and confusion that might result from the presence of the second wellbore immediately south of the blowout, the relief well location was spotted northwest from the blowout. The trajectory of the second relief well was planned to be due east from the surface location and then turning south toward the blowout.

The actual trajectory of the relief well is shown in Fig. 7.5. The surface location of the blowout well is also shown along with its anticipated trajectory. There were no directional surveys on the blowout well, but local drift tendencies indicated that it would drift to the northwest. As can be seen, the intercept was made northwest from the surface location.

As shown in Fig. 7.6, the intensity of the magnetic field increased exponentially as the relief well approached the blowout. The intensity began to increase at about 3600 ft (1100 m). At that point, the blowout wellbore was 53 ft (16 m) southwest from the relief well.

The target was clearly visible by a depth of 4019 ft (1225 m). At that point, the blowout wellbore was only roughly 12 ft (3.8 m) almost due west from the relief well. The azimuth of the relief well at that depth was 268 degrees. Pursuant to the active magnetic data in Fig. 7.7, the target was slightly right of high side or a little north of the present trajectory.

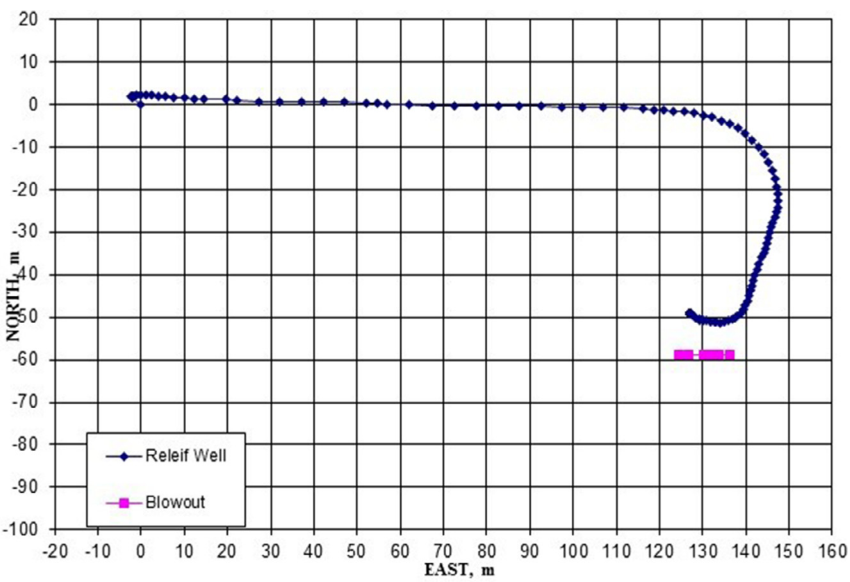

Fig. 7.5 An actual approach.

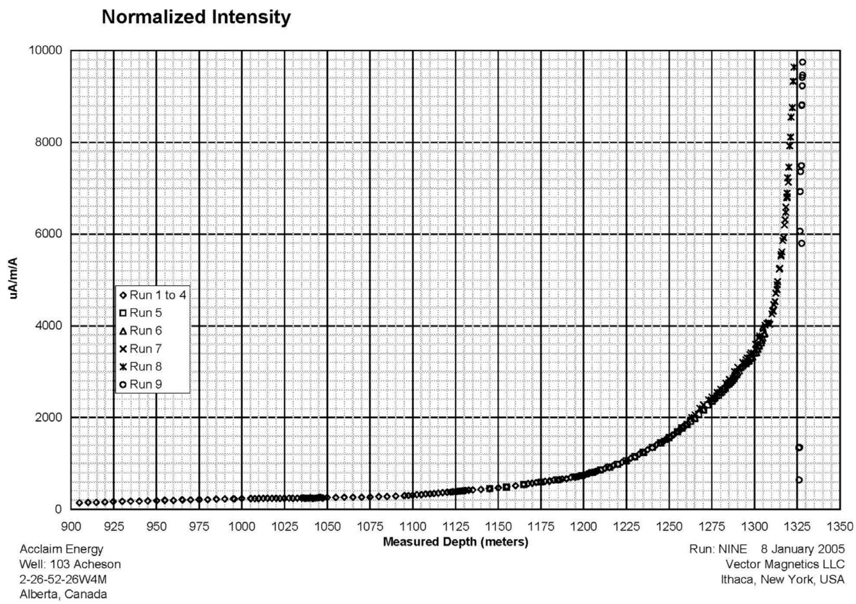

Fig. 7.6 Active magnetic intensity versus measured depth.

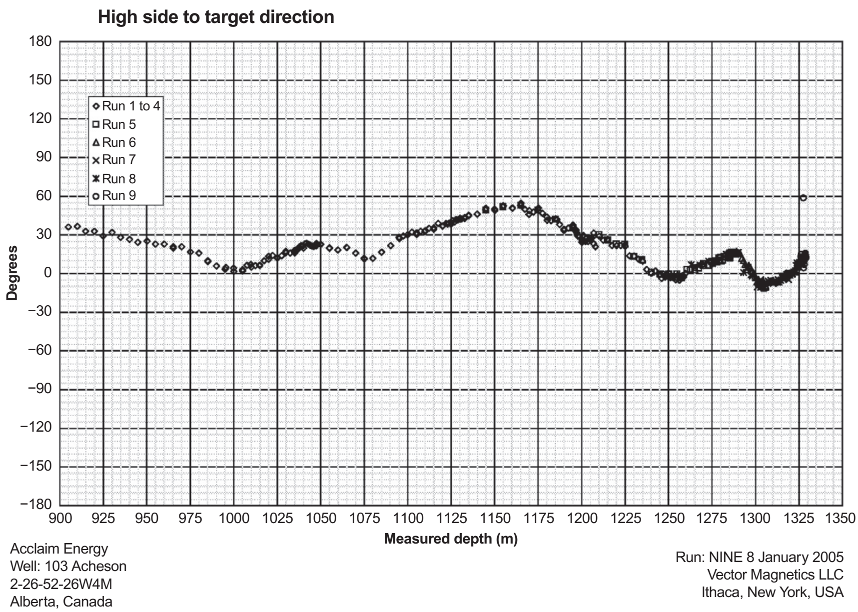

Fig. 7.7 Wellspot blowout azimuth direction from relief well.

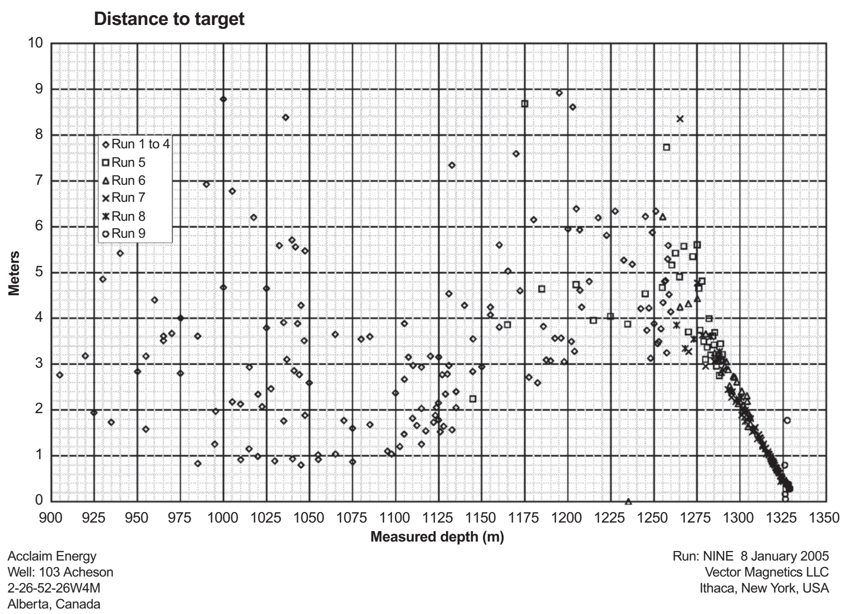

Fig. 7.8 Gradient ranging tool data.

By 4347 ft (1325 m), the magnetic intensity had increased almost ten-fold, and the blowout well was 1.5 ft from the center of the logging tool in the relief well to the center of the casing in the target well. The azimuth of the relief well was 308 degrees, and according to Fig. 7.7, the blowout was slightly to the right of high side.

As illustrated in Fig. 7.8, the gradient ranging tool began to accurately determine the distance to the blowout from about 10 ft (3 m).

All of the data are utilized in real time to produce a map view shown in Fig. 7.9 to guide the relief well to the blowout. Fig. 7.9 illustrates the distance and direction to the target along with the error bars for the predicted position. As illustrated in Fig. 7.9, the direction is more reliable than the distance until the target is within the range of the gradient ranging tool. The active magnetic survey data are presented as Table 7.1.

Killing a blowout from a relief well after a direct intercept is a ton of fun!! All should be prepared for the kill once communication is established. The blowout has usually been flowing for an extended period of time. Therefore, the flowing bottom-hole pressure will be substantially lower than the shut in bottom-hole pressure. And depending on the reservoir characteristics, the time required for the reservoir pressure to recover in the wellbore is long.

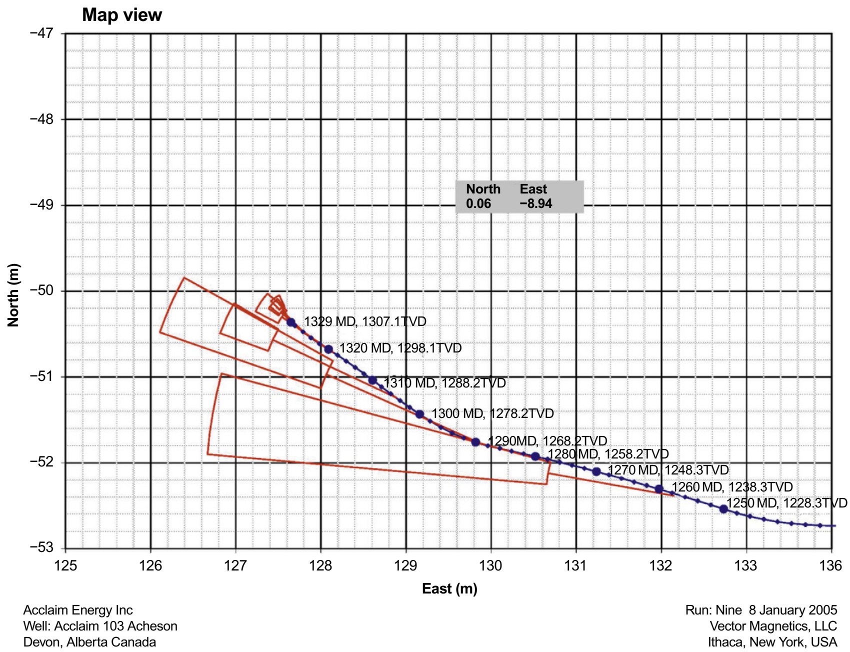

Fig. 7.9 Wellspot plan view output.

Of course, the relief well has full hydrostatic. Therefore, when the mill weakens the casing sufficiently, it will simply collapse, and the blowout wellbore will be exposed to the full hydrostatic in the relief well! What a shock that is! Of course, circulation will be lost at the relief well immediately. The rams should be closed and locked. The kill trucks will have been rigged into a kill spool beneath the rams. The target is then killed and cemented pursuant to a predetermined kill program.

Depending on geometry, the blowout is often killed by simply keeping the annulus in the relief well full. In other instances, sophisticated computer software is used to analyze the multiphase flow conditions and determine the required density of the kill fluid and the rate at which it must be pumped in order to control the well.

Some of the major companies have multiphase flow programs. At our company, my old friend and business partner Jerry Shursen wrote a program that we used to kill blowouts. It never failed us. It was based on work by Orkiszewski [1]. One program that is commercially available is marketed under the trade name Olga.

Table 7.1 Magnetic ranging target location

							Target location			
	Depth		Distance to target		Error		South		East	
Run #	Meters	Feet	Meters	Feet	Meters	Feet	meters	Feet	Meters	Feet
2	1132	3714	14	46	5	16	51.02	167.4	129.20	423.9
3	1202	3944	8	26	3	10	50.48	165.6	128.83	422.7
4	1258	4127	3.5	11	1	3	50.34	165.2	128.23	420.7
5	1289	4229	3	10	1	3	49.38	162.0	126.52	415.1
6	1304	4278	1.9	6	0.3	1	49.24	161.5	126.54	415.2
7	1319	4327	0.88	3	0.15	0.5	48.94	160.6	126.65	415.5
8	1325	4347	0.45	1	0.07	0.2	48.88	160.4	126.80	416.0
9	1331	4367	0.07	0.2	0.05	0.2	48.85	160.3	123.84	406.3

The first thing that must be realized in utilizing any of the available software including ours is that it is theoretically flawed. In my opinion, the best work in multiphase flow is presented in *API Monograph Volume 17—Multiphase Flow in Wells* by James Brill and others. When we developed our work, we consulted with Brill and others at the University of Tulsa.

Here is an overview of what we learned:

1. There is no relation between multiphase flow in horizontal flow and multiphase flow in vertical flow.
2. All multiphase flow equations utilize a multitude of empirical correlations.
3. All multiphase flow empirical correlations are based on flow up tubes 1 in or less in diameter.
4. No multiphase work has been done for flow through an annulus.
5. Multiphase flow work is done with a maximum of three fluids—oil, gas, and water.
6. No multiphase work was ever done with the fluids seen in a blowout—oil, gas, water, drilling mud, formation solids, etc.
7. No multiphase flow work has ever been done that simulated flow through an open hole of changing size and roughness, etc.

The bottom line is that the density, rate, and pressures predicted by any of multiphase flow programs adapted for use in blowouts are what should be described as a "best guess."

The guts of Olga are a tightly guarded secret. However, pursuant to what is presented in Ref. [2], Olga was developed in Norway as a tool to predict and understand multiphase flow in pipelines in the mountains of Norway. The correlations were developed in a 3280 ft horizontal flow loop that is 8 in. in diameter. The fluids used in developing the correlations were nitrogen for the gaseous phase and either naphtha, diesel oil, or lube oil as the liquid phase. The loop had only one vertical section that was 164 ft in height. The pressure in the system varied between 300 psi and 1400 psi. Obviously in actual practice, blowouts involve natural gas, oil, water, formation solids, drilling fluids, blood, and beer. They are difficult to model, and the best calculations cannot be expected to be very accurate. And since multiphase calculations rely heavily on empirical correlations, any system that varied from the experimental conditions could reasonably expected to be inaccurate. Further, it must be realized that any friction calculation relies, as Moody demonstrated, on the size of the flow path and its relative roughness. Who can know the size of an open hole much less its relative roughness? It can only be concluded that Olga is a beautiful piece of software that can, in my experience, generate a number in response to about any question but is technically flawed like all the rest.

A typical direct intercept relief well is schematically illustrated in Figs. 7.10–7.12. The relief well and the blowout well become a giant U-tube.

The vast majority of the time, the flowing bottom-hole pressure in the blowout well is much less than the hydrostatic pressure in the relief well.

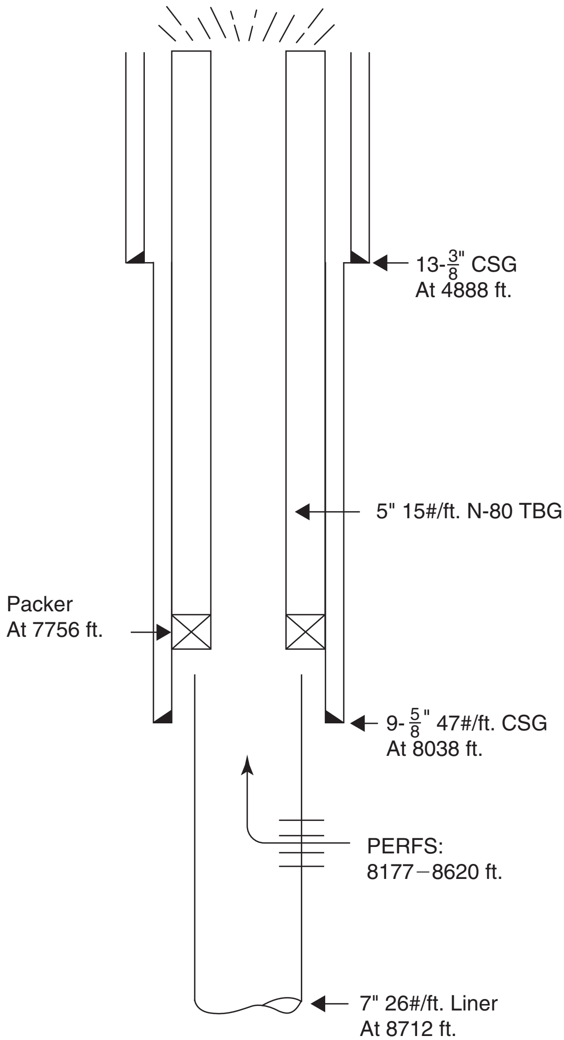

Fig. 7.10 The blowout wellbore.

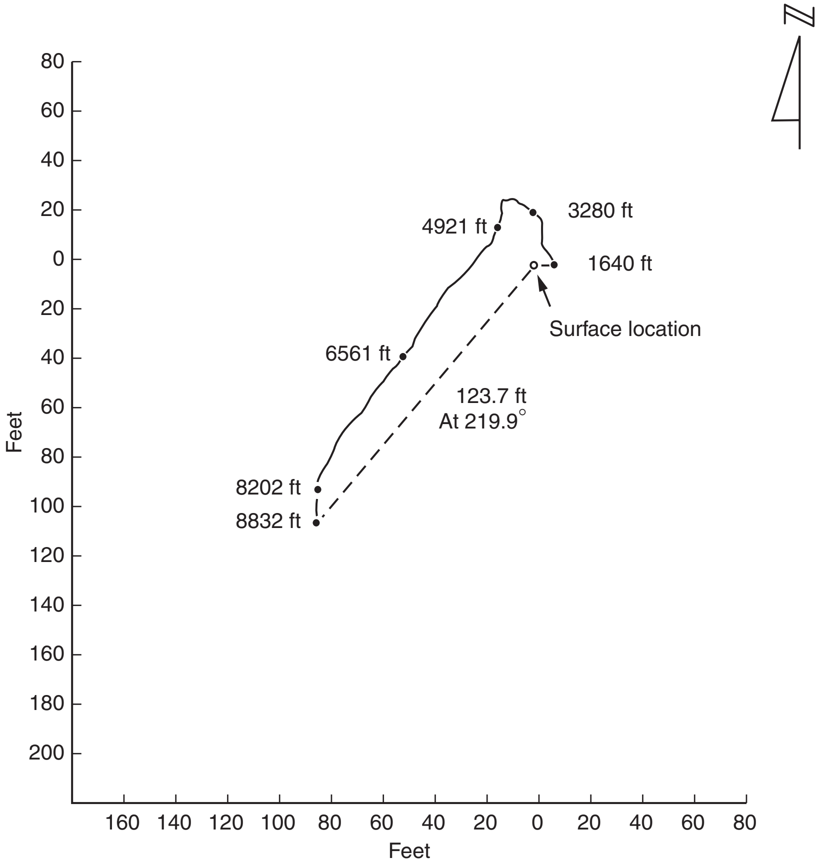

Fig. 7.11 The blowout wellbore trajectory.

Depending upon the geometry of the relief well when the intercept is made, the relief well will go on a vacuum (in the vast majority of instances); and it is a simple matter to kill the blowout well by keeping the hole full or pumping as needed to control and kill the blowout. Controlling and killing the blowout will be discussed later in this chapter.

THE DIRECT INTERCEPT RELIEF WELL

History of Development

The direct intercept is the preferred approach to control and kill the blowout. The technology required to intercept a blowout wellbore was perfected

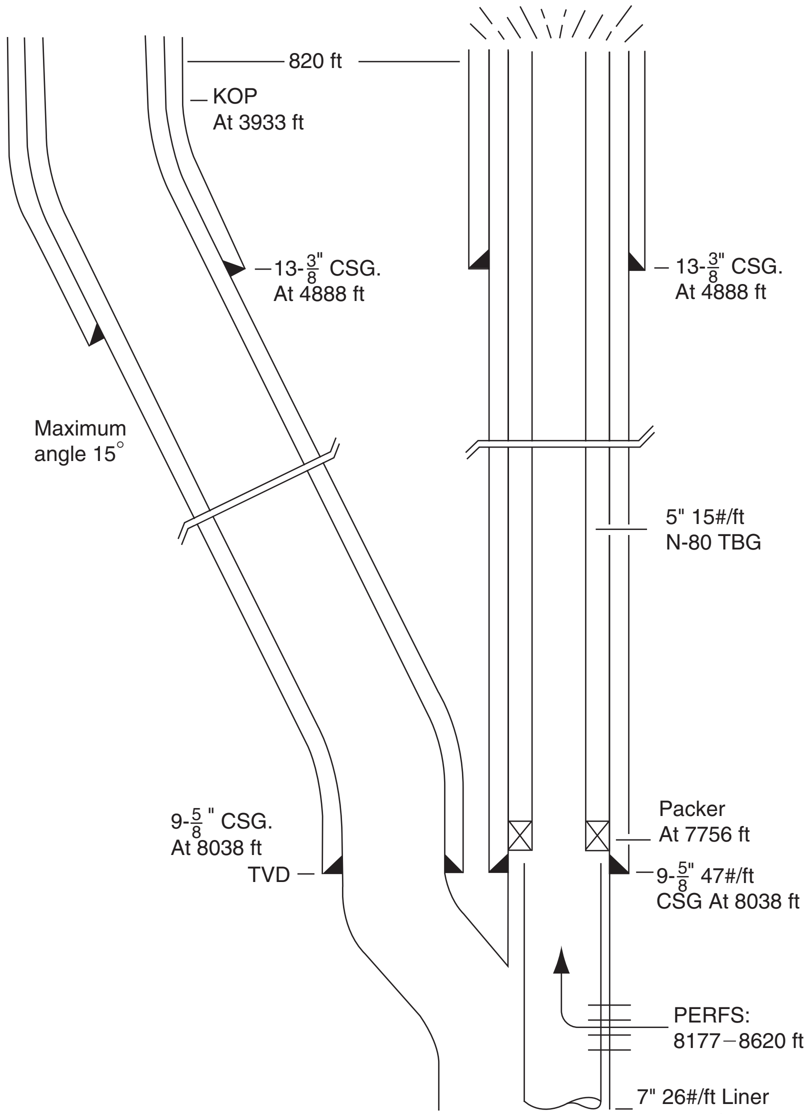

Fig. 7.12 The relief well intercept.

by Dr. Arthur Kuckes. Art is without a doubt the smartest guy I've ever had the pleasure of knowing. And, he is fun to work with.

In early 1980, Amoco experienced a blowout at the R.L. Bergeron No. 1 located in the Tuscaloosa trend near Baton Rouge, Louisiana. Systematic errors in the directional surveys combined with the limited investigative capability of Magrange's passive magnetics prompted Amoco to seek new alternatives. Amoco contacted Dr. Arthur Kuckes, a Cornell University physics professor. Dr. Kuckes pioneered the application of active magnetics. Art helped Amoco control and kill the Bergeron well.

With the additional technology developed at the Apache Key 1–11 relief well operation in 1981 (discussed later in this chapter), it became possible to intercept the blowout and establish direct communication. Since the advent of that technology, relief well intervention has become a certainty in most instances provided that there is a metallic target in the blowout well. Active magnetics proved to be much more reliable and diagnostic than the passive magnetics of that day. Little has changed since 1981. There have been improvements, but the basics have remained unchanged. It has been so successful; there has been little reason to improve.

This technology was pioneered by Art and his company Vector Magnetics, Inc., founded in Ithaca, New York. It has revolutionized well control and relief well drilling. In 2014, Art sold the relief well technology to Halliburton Energy Services.

How the Passive Magnetic Process Works

The Shell Oil Corporation Cox No. 1 in Rankin County, Mississippi, blew out on Mar. 25, 1970 from the Smackover while at a total depth of 21,122 ft. Surface intervention was impossible as a result of high concentration of hydrogen sulfide. However, no one had ever even contemplated a relief well to 21,000 ft. Directional drilling technology and inherent systematic survey error virtually eliminated any hope of drilling a relief well anywhere near the bottom-hole location of the blowout.

Shell's response pioneered then available relief well technology. Shell engineers designed the relief well to approach the blowout at about 10,000 ft. Sensitive magnetometers were then used to measure the earth's magnetic field and the distortion of that field resulting from the presence of tubulars possessing remnant magnetization. Numerous measurements were made from the relief well and sidetracks. These measurements were modeled and included data gathered with Schlumberger's ULSEL technology that gave at least some indication of distance when modeled sufficiently.

Shell's diligence and efforts were rewarded when the Cox No. 1 was intercepted by the Cox No. 4 relief well at a depth of roughly 10,000 ft. The relief well drilled into the blowout, and it was successfully controlled.

Unfortunately, no commercial service resulted from the Shell work at the Cox No. 1. Therefore, when Houston Oil and Minerals experienced a blowout in Galveston Bay in 1975, a reliable wellbore proximity logging service was not commercially available. In response, Tensor, Inc. was commissioned to develop a system, which became known as the Magrange service. The Magrange system was similar to the Shell work. Highly sensitive magnetometers were used to detect distortions in the earth's magnetic field resulting from the presence of tubulars in a well. This technology, characterized as passive magnetics, was successful at the Houston Oil and Minerals blowout and became the industry standard for several years. However, depth of investigation was limited to roughly 35 ft, and interpretation was less reliable than needed in some instances. Further, passive magnetics relies on the strength of magnetic poles created by the connections in the target wellbore. Therefore, readings can be taken only as often as there are connections in the target. In my experience, the interpretation of the data left much to be desired. The distance and direction interpretations involved as much art as science and were generally unreliable. Passive magnetics and Magrange technology were the state of the art from 1970 until 1981.

Comparing Active Magnetics With Passive Magnetics

I had a chance to compare the two systems at the Apache Key blowout in 1981. The Apache Key 1–11 blew out in October 1981. The well continued to deteriorate. I was hired as project manager in early 1982. Surface control was not an option because the well had cratered, and there was no known tubular integrity. Total depth at the Key was 16,400 ft, and there were no directional surveys. A relief well was considered to be the only hope of controlling the blowout. Elmo Blount at Mobil had pioneered relief well operations and killing a blowout from the relief well at the Arun blowout in Indonesia. Elmo was an old friend and classmate from OU. I contacted Elmo for his expertise and input. After a considerable study, we concluded that due to the reservoir characteristics at the Key, it would be impossible to communicate with the blowout if the relief well was more than 2 ft away from the blowout well. Therefore, a direct intercept would be required to control the blowout.

Directional drilling technology was nothing like it is today. All directional drilling had to be done with a bent sub in the well, and a wire line was run for orientation. Drilling was painfully slow. A relief well would require at least twice as many days to drill as the blowout well and was quite a challenge.

The Magrange technology had evolved from the earlier Shell work and was believed to be state of the art in wellbore proximity logging. Due to the depth and cone of uncertainty, it was estimated that as many as five passes through the cone of uncertainty would be required to locate the blowout wellbore. An in-depth study of regional drift tendencies narrowed the search, and the blowout wellbore was located on the first pass. However, due to the limitations of Magrange technology, the relief well passed the blowout wellbore, and a sidetrack was required.

On the second pass, the data were again inconsistent with the best engineering data representing the path of the blowout. To be wrong would mean another sidetrack. In despair, I started looking for alternatives. I somehow heard of Art and called him. I explained my dilemma in great detail and asked if he could help. Without a moment's hesitation, he said—yes, I can do that. He had answered so quickly and confidently that I thought—well, he must not have understood the question. So, I repeated myself. And, I got the same answer. I told him to pack his equipment and come to the Texas Panhandle.

He was a fun guy to watch. Clearly, he was very clever and quite eccentric. He worked with no. 2 pencil that he sharpened with his pocket knife. He had graph paper from Walmart, and his equipment was packed in an orange crate. He would graph his data, and when he ran out of room on his graph paper, he would cut another piece, tape it to the first, and continue.

I ran both Art's active magnetic tools and the Magrange passive magnetic system. I also ran the seek system that was an offshoot of Magrange. I did not let them compare notes. I asked each independently for their results. On the first run with both tools, the passive magnetic data interpretation was that the blowout was 12 ft south of the relief well. Their recommendation was to build angle, drill to the indicated target, and kill the well. The active magnetic interruption was that the blowout was one and one-half feet south of the relief well, and the relief well would pass the blowout in the next 60 ft.

To follow the passive magnetic recommendation would undoubtedly result in another sidetrack if the active magnetic interpretation was correct. And passive magnetic data accurately confirm a pass by the blowout from north to south due to the shift in polarity at the target. Therefore, the decision was made to drill another 60 ft and log with both systems. After drilling an additional 60 ft, the Magrange data confirmed that the relief well passed the blowout wellbore. Both systems were run throughout the remainder of the operation. There were several instances when the data conflicted, and on every occasion, the active magnetic interpretation proved to be correct. Ultimately, the active magnetic data were used to intercept and mill into the blowout wellbore at a true vertical depth of 16,400 ft, which remains the deepest relief well with a wellbore intercept.

Passive Magnetics Resurrected

After 1981 and until about 2008, the use of passive magnetics in relief well operations was a thing of the past. However, I did run into it again in about 2005 while on a relief well in Bangladesh. The directional company thought they might help through the interpretation of interference with their MWD tool. They gave it their best efforts but could not contribute anything of significance. In roughly 2008, it has resurfaced, and I had the opportunity to compare the two systems. I was working on a plugging project for a customer in which we had no directional data and questionable deviation data. The wells were old, and the deviation data were unreliable. The formations were anhydrites and limestones, which offer the toughest environment for active magnetics. On the first well, we passed through the cone of uncertainty with the first pass and should have seen the target if the deviation data were accurate. We saw nothing. We plugged the well back and passed through the cone of uncertainty at a shallower depth. We found the target and followed it to the point of intercept. The old deviation surveys from the target had clearly been run in the doghouse. The target well was far outside the cone of certainty for the first pass.

The service companies capitalized on our difficulties on the first pass and convinced the operator to try passive magnetics based on interpretation interference with MWD data. This writer has had opportunity to compare the active magnetics with passive magnetics, and in my opinion, the active magnetic technology is still superior and more reliable in every respect.

The wells were shallow in depth—about 5000 ft. The total drilling time for the intercept well using active magnetics was 15 days compared with the total drilling time of 21 days for the intercept well utilizing the passive magnetics. The passive magnetic approach required 20 ranging runs compared with nine ranging runs for the active magnetic system. We did finally intercept the target and kill it using passive magnetics. However, in the judgment of this writer, the results are much less reliable with passive magnetics. That is, it is apparent that a target is present with passive magnetics, but the distance and direction are less reliable.

In the aforementioned comparison, a direct intercept was made with the active magnetics. With passive magnetics in the comparable instance, an intercept was intended but not achieved. It was reported that the intercept

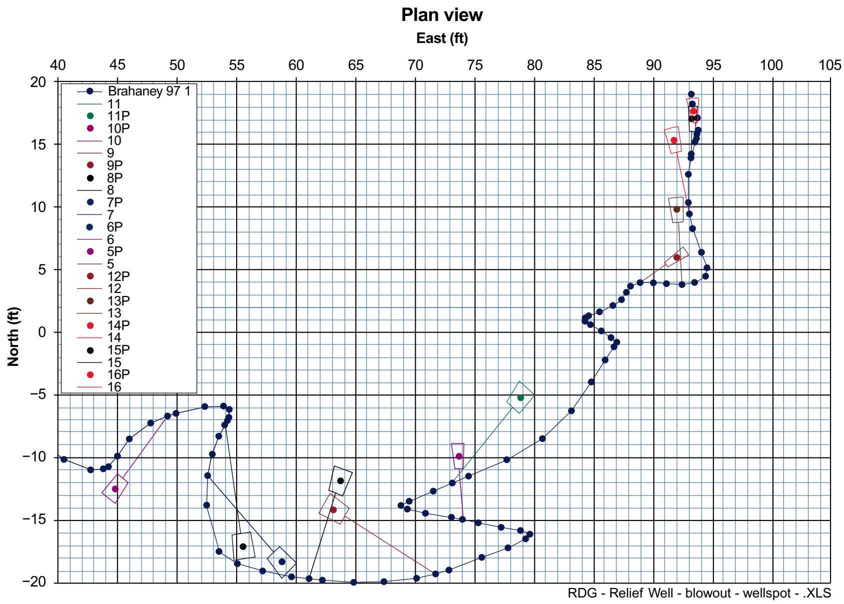

Fig. 7.13 Typical passive magnet data interruption.

well communicated with the target well in the perforated interval and communication was established. However, there was no confirmation that communication had been established. Cement was pumped into the intercept well and hopefully into the target well. That passive magnetic presentation is shown in Fig. 7.13.

As mentioned, Fig. 7.13 is a typical passive magnetic data interruption, in my experience. Clearly, the target well could not have been in all those places, and just as clearly, the intercept well was excessively steered in the effort to chase and intercept the target. As shown, the position of the target was uncertain until the end. Once the relief well was very near to the target, the magnetic interference from the MWD tools was strong, and the proximity seemed to become more reliable. However, in the early stages of the approach, neither distance nor direction seemed to be very reliable.

THE GEOMETRIC RELIEF WELL

History of Development

A geometric relief well is one that simply gets as close to the target well as directional survey accuracy will permit. That is, the relief well is drilled as close to the suspected bottom-hole location of the blowout well as data accuracy will permit, and water is pumped until communication is established. The first relief wells were geometric relief wells. The industry had little faith in the reliability of geometric relief well operations to control a blowout. In far too many instances, it was not possible to establish communication.

The Lodgepole blowout in 1981 west of Edmonton, Alberta, forever changed the industry. The huge clouds of deadly hydrogen sulfide threatened the entire city of Edmonton. Two firefighters were killed. It was ultimately masterfully controlled by Boots Hansen, Pat Campbell, and their crew when they capped the well, while it was still burning—something that had been done only a handful of times and never under such difficult circumstances. It is interesting to note in the Amoco report of the incident that a relief well was not considered because of the unreliability of relief wells. In those days, directional surveys were not common in onshore operations. And, directional surveys on offshore wells were often inaccurate or contained huge systematic errors.

The Paulsen oil well fire at Canton, Oklahoma, was known nationally and is a case in point. Airplanes flying to Oklahoma City rerouted their flight plan to pass over the sight so passengers could see the huge fire. The fire started in August 1964 and burned until June 1965. The fire could be seen at night from many miles away. Red Adair was called in to help and failed.

In an attempt to squelch the fire, two relief wells were drilled and failed. A detailed study of natural drift tendency in offset wells gave engineers a better idea of where the bottom-hole location might be. The third attempt incorporated the drift data, and the relief well was drilled 200 ft at the surface from the original hole and intended to be 75 ft from the bottom of the blowout. This third attempt was finally successful, and the blowout was killed.

The Bay Marchand fire was historic. Platform "B" was launched in July 1969, and by Dec. 22, 1970, wells had been drilled and completed. The platform was producing 17,500 bopd and 40 mmscfpd gas. Two wells were being drilled, and B-21 was being worked over when something went wrong, B-21 blew out, and the platform caught fire.

Again, Red Adair was summoned but could do nothing due to the intensity of the fire and the proximity of the wells on the platform. The only viable alternative was multiple relief wells. There were directional surveys of the day available for all the wells. The only proximity log available was the Schlumberger ULSEL technology, which utilized the interference on the resistivity survey caused by nearby tubulars. This technology was little more than nothing. It offered no distance or direction—merely presence—and was limited to a minimal distance depending on formation resistivity.

Therefore, all the operator could hope for was that the relief well would be close enough to the blowout to establish hydraulic communication and kill the well. Over the course of the next few weeks, five rigs drilled ten relief wells to kill eleven blowouts. Extensive reservoir modeling was performed and utilized to establish targets. In each case, the target was a maximum 25 ft radius for each producing horizon. Pursuant to the surveys, the actual distances were as close as 12 ft and as far away as 150 ft.

The general approach was to inject water into the relief well until water was observed at the blowout. At that point, mud would be pumped to kill the well. Breakthrough varied from 150 bbl at the blowout calculated to be 12 ft away to 31,750 bbl for the blowout calculated to be plus 120 ft away. The instance where the distance was more than 150 ft between the relief well and the blowout required 117,000 bbl for 100% water at the blowout. Only one blowout could not be killed with the relief well and required surface intervention.

In some instances, active magnetics cannot be run, and passive magnetics is the only alternative. One such instance occurred at the Crestar Little Bow near Enchant, Alberta. Crestar drilled a horizontal well, and it blew out. A geometric relief well was commenced before I became involved in the operation. I recommended a direct intercept second relief well designed to intercept the blowout at the kick off point. In the meantime, we worked with what we had—the geometric relief well.

Interestingly, prior to my arrival, Crestar had tried to kill the blowout from a nearby producing well. According to the survey data, the wells were only 80 ft apart. I don't recall how much water was pumped in the effort to communicate with the blowout, but it was considerable. The blowout never blinked.

Crestar then decided to drill a geometric relief well based on the survey data. The relief well was vertical and intended to hit or get very near the blowout horizontal section in the producing interval. After the relief well passed the TVD of the horizontal leg of the blowout, an active magnetic survey was run.

At the Little Bow, the active approach was not applicable, and passive interpretation indicated the relief well was roughly 5 ft (1.5 m) from the blowout well. Fig. 7.14 is an example of the active magnetic output for a vertical relief well passing a horizontal wellbore. As can be seen in Fig. 7.14, the presence of the blowout is not evident until the relief well

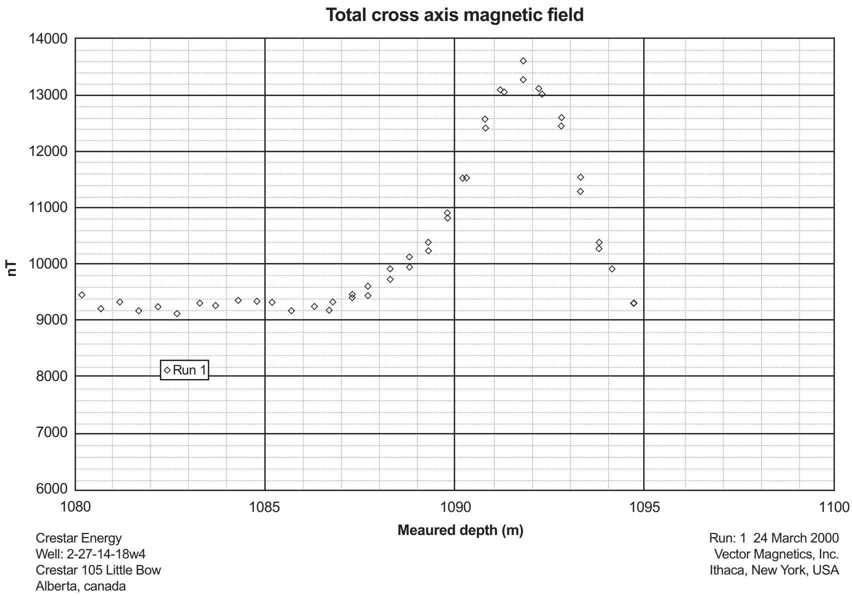

Fig. 7.14 Active magnetics from the Little Bow well.

has passed the blowout. Therefore, it is not possible to approach and intercept the blowout with the relief well.

We decided to try to establish communication. In this case, communication was established between the relief well and the blowout with roughly 3000 bbl of brine water. However, the communication was insufficient to control the well. Two days later, pumping operations resumed, and communication was reestablished. The well was killed and left for the night. Since the communication was through the productive interval, the kill fluid leaked off, and the well kicked.

Communication became easier with time. The well was killed a second time the following day, and cement was pumped as soon as the well was dead.

Niko was a Canadian company with operations in Bangladesh. In early January 2005, a blowout occurred at their Chattak 2, which was about 1 h north of Dhaka by helicopter. While pulling out of the hole on a trip, the well kicked and was shut in. With only about 1000 ft of surface casing set, the well cratered, and the rig completely disappeared into the crater. It was an astonishing sight to see. The crater appeared to be no larger than the rig and substructure. From the appearance, the rig simply sank into the crater.

It didn't fall over and sink. It sank with the derrick standing! That had to mean that the 1000 ft of surface casing and 1500 ft of drill pipe and collars simply sank into the crater. How all that happened staggers the imagination. What happened to the rig, substructure, wellhead, surface casing, and drill pipe is anyone's guess.

When I arrived, gas was coming up for miles around the crater. The prevalent fracture pattern was in the north-south direction. Gas was coming to the surface in homes and shops all around the location but was worse in the direction of the fracture pattern.

With the blowout zone at 1837 ft (569 m), a surface location for a direct intercept relief well had to be very close to the surface location of the blowout. Since all of the waters running off the Himalayas flows through Bangladesh to the sea, much of the country is under water one-half of the year, and the other half, the country not flooded is rice paddy. Almost all of the land area that does not flood during the wet season is inhabited. There was simply no place to build a location for a relief well. The only direction that was even a possible location was immediately west of the blowout. The geometry favored a surface location about 300 ft west from the blowout surface location, and an island had to be built.

Building that island was an amazing thing to see. Niko personnel along with the local contractors built a pipeline from a nearby river to the proposed location, which was beneath the waterline. They then pumped river water laden with river sand to the proposed location and built an island!

All of the geologic experts in Bangladesh and another from the United States agreed that there could not be a significant accumulation of gas above the regional seal. The direct intercept relief well plan was to make a pass about 30 ft away from the anticipated wellbore of the blowout but not crossing the north-south fracture plane. There was no history of a blowout communicating with a relief well 30 ft away. However, the geologic experts were proved wrong when the relief well encountered a significant accumulation of gas above the regional seal. The relief well blew out and was lost. It could not be shut in because shutting in would cause the well to crater as did the first blowout and would endanger lives in the surrounding village.

There was no place to put another rig that would allow a direct intercept. Therefore, a geometric relief well was planned and executed. The Chattak 2B was drilled and passed the blowout wellbore at an angle of 45 degrees. When the well blew out, the bit was at the top of the blowout zone. Therefore, it was anticipated that there would be no metallic target for active magnetic analysis. However, active magnetics were run, and much to everyone's pleasant surprise, the drill pipe was across the blowout interval. Interpretation of the data was conclusive that the relief well passed within 1 m of the blowout wellbore. Communication was established. Since the zone was normally pressured, water was continuously pumped at rates of 50 bpm for a week before the blowout finally died.

As can be seen in these comparisons, the geometric relief well is not as reliable or predictable as the direct intercept relief well. Whenever possible, the direct intercept relief well is preferred. However, there are times when the only possibility is the geometric relief well.

SUMMARY

In summary, regardless of the conditions, a relief well, whether it is a geometric relief well or a direct intercept relief well, should be considered as the most reliable approach for blowout intervention. Depending on the depth and complexity of the blowout wellbore geometry, a relief well could very well be the preferred alternative. In most instances today, general relief well design is included in the contingency plan, and the plan is refined and commenced as soon as a blowout occurs. Surface intervention proceeds as rapidly as possible, and the relief well is utilized if it arrives at the blowout before surface intervention can be successful.

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CHAPTER EIGHT

The Underground Blowout

24 February

2009 hours—well kicked. 20 in. set at 3100 ft. Shut well in with 1300 psi.

2121 hours—pressure declined to 700 psi over time.

25 February

0530 hours—well broached one half mile southeast from rig. Flow estimated at over 100 mmscfpd. Rig abandoned except for skeleton crew of 15 men.

1630 hours—Helicopter lifted off with five of the remaining crew. Well broached under the rig. Rig listed 15–20 degrees. Boil as high as helideck and 200 yards around rig. Helicopter landed and rescued the men remaining on the rig. There were no injuries.

An underground blowout is defined as the flow of formation fluids from one zone to another. Most commonly, the underground blowout is characterized by a lack of pressure response on the annulus while pumping on the drillpipe or by a general lack of pressure response while pumping. The underground blowout can be most difficult, dangerous, and destructive. It can be difficult because the conditions are hidden and can evade analysis. Often, the pressures associated with an underground blowout are nominal, resulting in a false sense of security.

It can be dangerous because some associate danger with sight. In many instances, there is no physical manifestation of the underground blowout. If a well is on fire or blowing out at the surface, it commands respect. However, if the same well is blowing out underground, it is more easily ignored. Since the underground blowout is not seen, it is often not properly respected.

If the flow is to a shallow formation (less than 3000 ft), there is a very real possibility the flow will fracture to the surface. This possibility is greater in young sediments such as those common to coastal areas and offshore.

Blowout and Well Control Handbook
http://dx.doi.org/10.1016/B978-0-12-812674-5.00008-0

Fig. 8.1 Blowout in Bolivia.

At a location in Bolivia, the flow broached to the surface and created a crater more than 100 m in diameter (Fig. 8.1). At least one wellhead, a workover rig, mud tanks, and several pump trucks disappeared into the crater and were never recovered.

Shallow underground blowouts in offshore operations can be even more dangerous. There is no place to run. If the flow fractures to the surface, the only safe getaway from the well is by helicopter. If the sea is gasified, boats lose their buoyancy, as do life preservers.

Another reason that shallow underground blowouts are more dangerous offshore is that the sediments are very young and the flow is more likely to surface immediately beneath the rig. Jack-ups and platforms are the most vulnerable. If the crater is beneath the rig, it can destabilize the structure, causing it to topple.

Floating operations have a unique problem. A floating rig loses buoyancy in a gasified sea. Ship-shaped floating rigs have been lost under the described conditions. Semisubmersible rigs are more stable because the floatation devices are several feet beneath the surface of the sea.

I was on the deck of the rig shown in Fig. 8.2 when the flow fractured to the surface. We were in only about 300 ft of water. The flow rate was in the hundreds of millions of cubic feet of gas per day. It is a miracle the rig didn't

Fig. 8.2 Underground blowout with a semisubmersible.

tip over as it listed several degrees—very near the critical list. The boil was as high as the deck and at times dwarfed the rig. I do not mind admitting that I was scared and thought my time had come.

The forces were so violent that the riser and drillpipe were sheared at the seafloor. After the well bridged, the crater was determined to be 400 m in diameter and more than 100 m in depth. There was never any sign of the subsea blowout preventer stack even using magnetometers.

Water depth is an ally in a situation such as this. As the depth increases, so does the likelihood that the plume will be displaced away from the rig by the current. In very deep water, the probability that the plume will be under or near the rig is remote. In that respect, deep water drilling is safer than shallow water drilling or drilling from a platform or jack-up.

Underground blowouts are generally more challenging than surface blowouts. The volume of influx is not known nor is the composition. Further, the condition of the wellbore and tubulars that are involved is not reliably descriptive. The well control specialist is confronted with the necessity of analyzing and modeling the blowout and preparing a kill procedure. The tools of analysis and modeling are limited.

Additionally, the tools and techniques should be limited to only those absolutely necessary since any wireline operation is potentially critical. With the underground blowout, the condition of the wellbore can never be known with certainty, and the risk of sticking or losing wire and tools is significantly increased. Stuck or lost wire and wireline tools can be fatal or at least limit future operational alternatives.

Since the consequences of an underground blowout can be severe, critical questions must be answered:

1. Should the well be shut-in?
2. Should the well be vented to the surface?
3. Is the flow fracturing to the surface?
4. Can the losses be confined to a zone underground?
5. Is the casing capable of containing the maximum anticipated pressures?
6. Should the casing annulus be displaced with mud or water?
7. If the casing annulus is to be displaced, what should be the density of the mud?
8. Is the flow endangering the operation and the personnel?

To vent or not to vent—that is the question! Personally, I love to vent a well. Yet, apparently most are afraid to let a well blow at the surface. It almost seems that flowing underground is somehow different than flowing to the surface. Certainly a well has to be properly equipped and rigged if it is to be vented at the surface, and most rigs are not. As a result, rerigging the choke manifold and flow lines is often the first thing that has to be done.

At the TXO Marshall, the wellhead pressure was being held such that part of the flow from the well was to the surface and part beneath the surface. The quantity being lost was unknown. However, when relief well operations were commenced, it was impossible to drill below approximately 1500 ft without blowing out. The Marshall was rigged up and the surface pressure was drawn down below a few hundred pounds. The measured production increased by about 15 mmscfpd and the underground charge ceased. Relief well operations were conducted without incident.

Except when diverters are used, venting a well offshore is generally not possible. On platforms and jack-ups, it is very difficult to rig up a satisfactory surface system. In floating drilling, any venting operation would be hampered by the surface system and the small choke lines. In addition, the sediments are incompetent and would most likely collapse if the well were flowed very hard.

At the Trintomar Pelican Platform, a drilling well collided with a producing well at a relatively shallow depth. The loss of the platform was a legitimate concern. Fortunately, it was possible to vent the well through the production system and prevent cratering beneath the platform.

The key to venting the well is this: The well must be flowed just enough to eliminate the cross flow downhole. How can we determine when cross flow is eliminated? It's simple. Just continue to open the well up at the surface until the surface pressure begins to decline. At that point, the preponderance, if not all, of the gas being produced will be produced at the surface.

Unlike classical pressure control, there are no solutions that apply to all situations. The underground blowout can normally be analyzed utilizing the surface pressures and temperature surveys. The noise log can be confusing. In all instances, the safety of the personnel working at the surface should be the first concern, and the potential for fracturing to the surface must also be considered carefully.

The temperature survey is generally the best tool for analyzing the underground blowout. However, for several reasons, analyzing temperature surveys is not always easy.

Typically, in my experience, the geothermal gradient is not well-known in a given area. I always begin by establishing the geothermal gradient in the area of interest. This must be done prior to running the temperature survey. If not, everyone will try to fit the temperature survey to the presumed geothermal gradient or vice versa. Therefore, it is preferable to agree on the geothermal gradient prior to running a temperature survey.

In one instance, an engineer attempted to dismiss a temperature anomaly by saying that the geothermal gradient in the area was consistently experiencing a sudden 10 degree shift. Of course, the geothermal gradient does not suddenly shift several degrees naturally. He tried to offer MWD data in support of his premise. The only good source of geothermal gradient data is from a shut-in gas well. If a reliable gradient is not available, shut-in a nearby well for 72 h and run a temperature survey to establish the gradient.

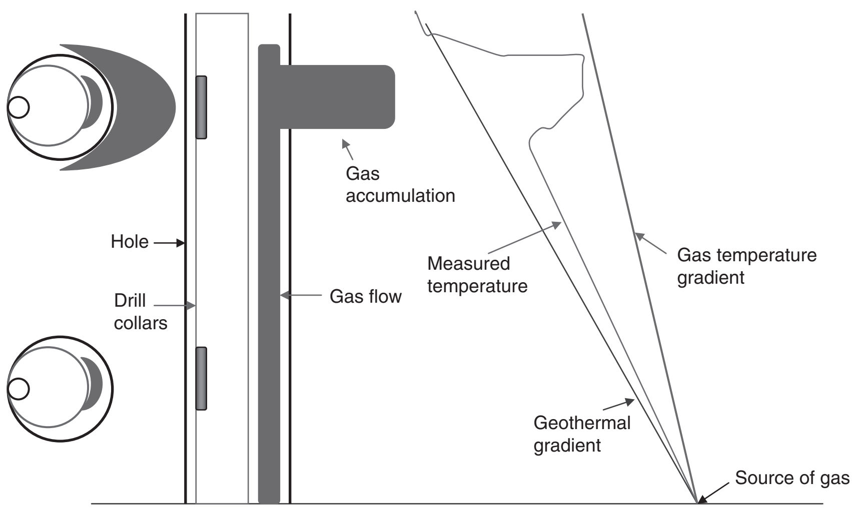
Another common problem is thermal instability. In my experience, the biggest mistake in running temperature surveys is running the survey too soon after pumping. Temperature surveys must not be run until the conditions in the well have stabilized. If the well has not reached thermal equilibrium, any attempt to analyze temperature information is pure speculation. I've seen good engineers argue for hours over a survey run in unstable conditions. If the well is not in thermal equilibrium, anyone's guess is as good as anyone else's guess—but all are just guesses.

Thermal equilibrium can usually be obtained in a matter of a few hours. If in doubt, wait a couple of hours and rerun the survey. The temperature tool should be run first in a suite of logs and the values recorded while logging down. Data obtained by logging up or logging again immediately after the first run are worthless.

Another common and often fatal mistake is to interpret the data from the typical log presentation. In so doing, huge anomalies have been overlooked, and in some instances, small, meaningless fluctuations have been misinterpreted as severe problems. I much prefer to obtain the data digitally—even if I have to read it off the log—and present it on a spreadsheet and in graphic form such as presented in this text. These presentations take a little time and work but are worth the effort.

Usually, there is considerable argument about the appearance of a temperature anomaly. Several variables will affect the appearance of the anomaly. Its appearance is a function of the flow path, the density of the flow stream, the volume rate of flow, and the distance between the flowing zone and the zone of accumulation.

Normally, the flow is outside the drill string. In that case, the temperature profile can be anticipated to look like Fig. 8.3. As shown in Fig. 8.3, the temperature profile is affected by the temperature of the hot fluid leaving bottom and the temperature of the surrounding environment. The



1 - Temperature Tool records a compromise between gas gradient and geothermal gradient. Flow and heat transfer reaches steady state. Recorded temperature is not as high as the temperature of the gas or as low as the temperature of the formation

2 - Temperature Tool records a compromise between gas gradient and geothermal gradient. In this case, the large accumulation of gas causes the temperature tool to record a higher temperature. The recorded temperature is not as high as the temperature of the gas and not as low as the temperature of the formation

3 - Above the zone of loss, the temperature tool is only influenced by the formations surrounding the tool

Fig. 8.3 Theoretical underground blowout temperature profile.

measured temperature will not be as high as the temperature of the flowing fluid and will not be as low as the surrounding environment. Rather, the measured temperature will be a compromise between all the thermal bodies detected by the measuring device. Further, the surrounding environment will never warm to the temperature of the flowing fluid, and the flowing fluid will never completely cool to the temperature of the surrounding environment—as long as the well continues to flow.

The flowing fluid stream will lose heat as it moves up the well according to the established laws of thermodynamics. A small flow will not retain as much heat as a large flow and, as a result, will not deviate as far from the established geothermal gradient. The density of the flow will affect the size of the anomaly. Gas does not retain heat as well as oil or water.

When the flowing fluid reaches the zone of accumulation, the volume of flowing fluid becomes larger, relative to the surrounding environment, and the temperature device will record an increase in temperature. Of course, the flow stream is not warmer at the zone of accumulation. There is simply relatively more fluid volume.

The size of the temperature anomaly in the zone of accumulation is also a function of the same variables. The higher the flow rate, the greater the density of the flow stream, the farther the distance between the flowing zone and the zone of accumulation, the bigger the anomaly.

A typical temperature profile for an underground blowout flowing outside the drill string is shown and explained in Fig. 8.4. In this instance, the anomaly deviated from the established geothermal gradient by more than 50°F. More than 5000 ft separated the zone of accumulation from the blowout zone, and the well was in an area famous for flowing large volumes of gas. Many temperature anomalies are not this dramatic.

The temperature profile for a strong water flow in North Africa is shown in Fig. 8.5. Since water retains heat, there is a 1°C drop in temperature between the source at 700 m and the surface.

Fig. 8.27 illustrates the difference between a temperature profiles of a flow outside the drill string compared with that of a flow inside the drill string. The profile noted as "1st Run" was obtained when the flow was outside the drill string. The well was subsequently killed but the inside of the drill string was not adequately plugged.

Consequently, when the inside of the drill string was cleaned out, the well kicked off up the drill string. As shown in the depiction of the second blowout in Fig. 8.27, the temperature anomaly was much greater compared with the first run and had different characteristics. The primary difference is

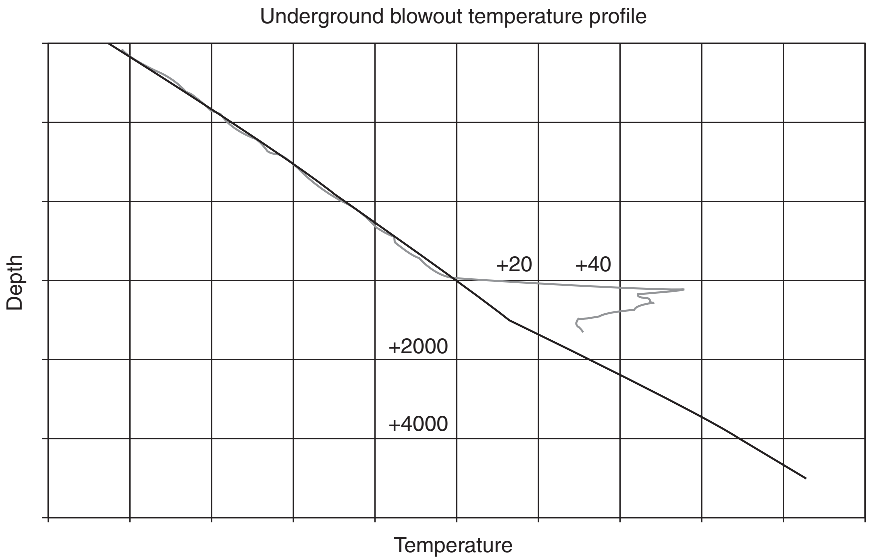


Fig. 8.4 Actual underground blowout temperature signature.

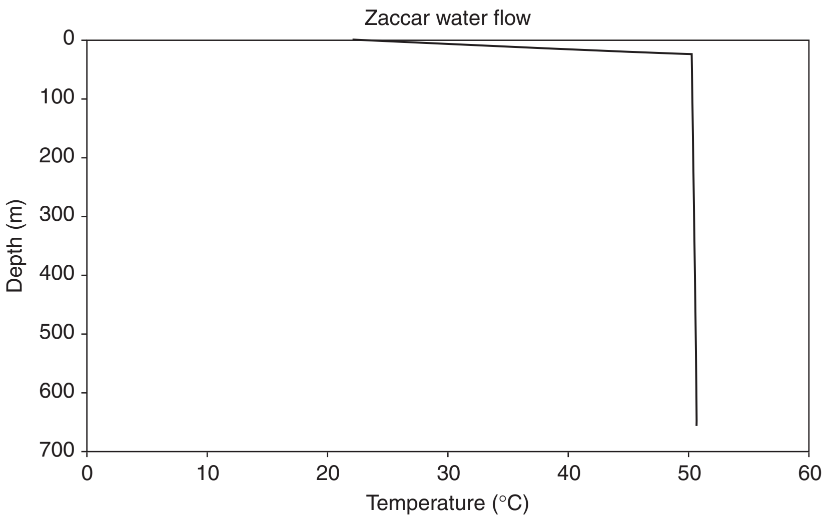


Fig. 8.5 Temperature profile, Zaccar water flow, Algeria.

that the local environment does not as greatly influence the measured temperature. Therefore, the measured temperature will simply increase linearly with respect to the maximum, and there will not be a large anomaly in the zone of accumulation.

It is obviously important to assess the hazards associated with the conditions at the blowout. In temperature survey analysis, it should be noted that the temperature of the flowing fluid will be essentially the same as the temperature of the reservoir from which it came. Therefore, if the flow is from a deep formation into a shallow formation, there should be an abnormally high temperature in the zone of loss.

Surface pressures are a reflection of the conditions downhole. If the surface pressure is high, the zone of loss is deep. Conversely, if the surface pressure is low, the zone of loss is shallow. If the density of the annular fluids is known, the depth to the zone of loss can be calculated.

The noise log is helpful in some instances. The flow of fluids can generally be detected with sensitive listening devices. However, in some instances, the blowout goes undetected by the noise log, while in other instances, the interpretation of the noise log indicates the presence of an underground flow when there is none. The application of these principles is best understood by consideration of specific field examples.

CASING LESS THAN 4000 FEET

With the casing set at less than 4000 ft, the primary concern is that the underground blowout will fracture to the surface and create a crater. If the blowout is offshore, it is most probable that the crater will occur immediately under the drilling rig. If the productivity is high, then the crater will be large and the operation will be in great peril.

At one operation in the Gulf Coast, several workers were burned to death when the flow fractured to the surface under the rig. At another operation in the Far East, a nine-well platform was lost when the flow fractured to the surface under the platform. At still another operation, a jack-up was lost when the crater occurred under one leg. Drill ships have been lost to cratered blowouts.

The blowout at the Pelican Platform offshore Trinidad is a good example. Pelican A-4X was completed at a total depth of 14,235 ft measured depth (13,354 ft true vertical depth). The well was contributing 14 mmscfpd plus 2200 bbl condensate per day at 2800 psi flowing tubing pressure. Bottom-hole pressure was reported to be 5960 psi. The wellbore schematic for the A-4X is shown in Fig. 8.6.

At the Pelican A-7, $18\frac{5}{8}$ in. surface casing was set at 1013 ft and cemented to the surface, and drilling operations continued with a $12\frac{1}{4}$ in. hole. The wellbore schematic for the Pelican A-7 is presented as Fig. 8.7.

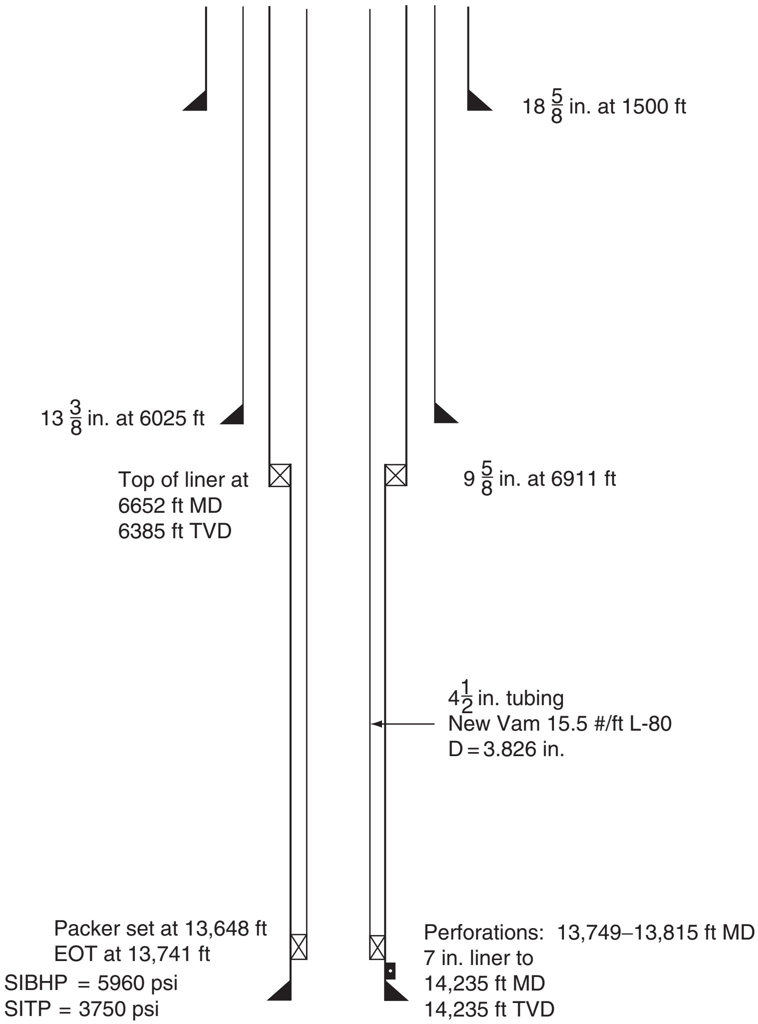


Fig. 8.6 Pelican A-4X.

The directional data indicated that the A-7 and A-4X were approximately 10 ft apart at 4500 ft. However, in the early morning hours, the A-7 inadvertently intercepted the A-4X at 4583 ft. The bit penetrated the $13\frac{3}{8}$ in. casing, $9\frac{5}{8}$ in. casing, and $4\frac{1}{2}$ in. tubing. Pressure was lost at the A-4X wellhead on the production deck and the A-7 began to flow. The A-7 was diverted and bridged almost immediately. The A-4X continued to blowout underground. With only 1013 ft of surface pipe set in the A-7, the entire platform was in danger of being lost if the blowout fractured to the seafloor under the platform.

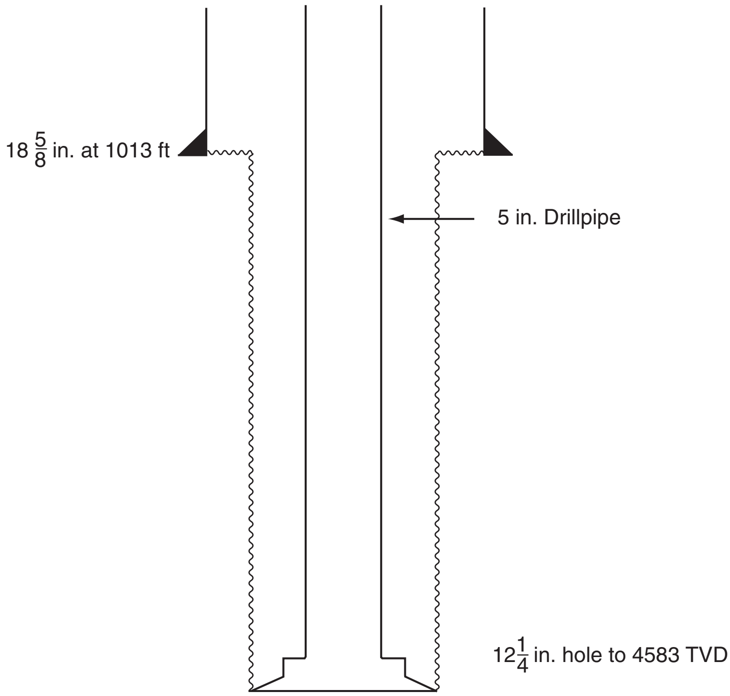


Fig. 8.7 Pelican A-7.

After the intercept, the shut-in surface pressure on the tubing annulus at the A-4X stabilized at 2200 psi. The zone into which the production is being lost can be approximated by analyzing this shut-in pressure. The pressure may be analyzed as illustrated in Example 8.1:

Example 8.1

Given:

Fracture gradient, $F_g = 0.68$ psi/ft

Compressibility factor, $z = 0.833$

Required:

The depth to the interval being charged.

Solution:

The gas gradient, ρ_f, is given by Eq. (3.5):

$$\rho_f = \frac{S_g P}{53.3 z T}$$

when

S_g = specific gravity of the gas

Continued

Example 8.1—cont'd

P = pressure, psia
z = compressibility factor
T = temperature, °Rankine

$$\rho_f = \frac{0.6(2215)}{53.3(0.833)(580)}$$

$\rho_f = \mathbf{0.052\ psi/ft}$

The depth to the interval being charged is given by Eq. (8.1):

$$F_g D = P + \rho_f D \tag{8.1}$$

or rearranging

$$D = \frac{P}{F_g - \rho_f}$$

$$D = \frac{2215}{0.65 - 0.052}$$

$$D = \mathbf{3704\,ft}$$

This analysis of the shut-in surface pressure data indicated that the flow was being lost to a zone at approximately 3700 ft.

As confirmation, a temperature survey was run in the A-4X and is presented as Fig. 8.8. Also included in Fig. 8.8 are static measurements from the A-3, which were utilized to establish the geothermal gradient. The interpretation of the temperature data was complicated by the fact that the flow path of the hydrocarbons being lost was from the A-4X into the A-7 wellbore and ultimately into a zone in the A-7 wellbore.

The high temperatures at 3600 ft shown in Fig. 8.8 were as expected and consistent with the pressure data analyses indicating the zone of charge to be at approximately 3700 ft. Pursuant to the analysis of the offset data, the normal temperature at 3600 ft would be anticipated to be approximately 130°F. However, due to the flow of the gas into the interval at 3600 ft, the temperature at that zone had increased by 45 degrees to a temperature of 175 degrees.

By similar analysis, the heating anomaly from 500 to 1000 ft could be interpreted as charging of sands between 1000 ft and the seafloor. Pursuant to that interpretation, cratering and the loss of the platform could result.

Further analysis was warranted. When evaluated in conjunction with the relative position of the two wells, the condition became apparent. Fig. 8.9

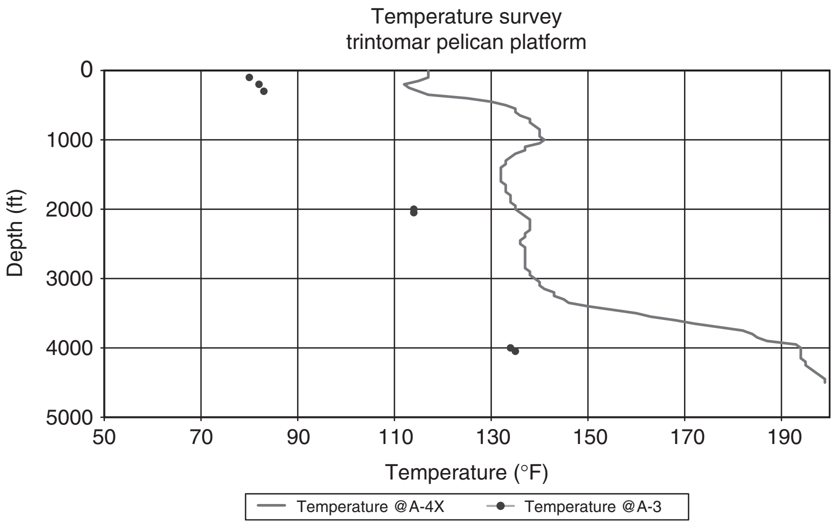


Fig. 8.8 Temperature survey in the Pelican A-4X.

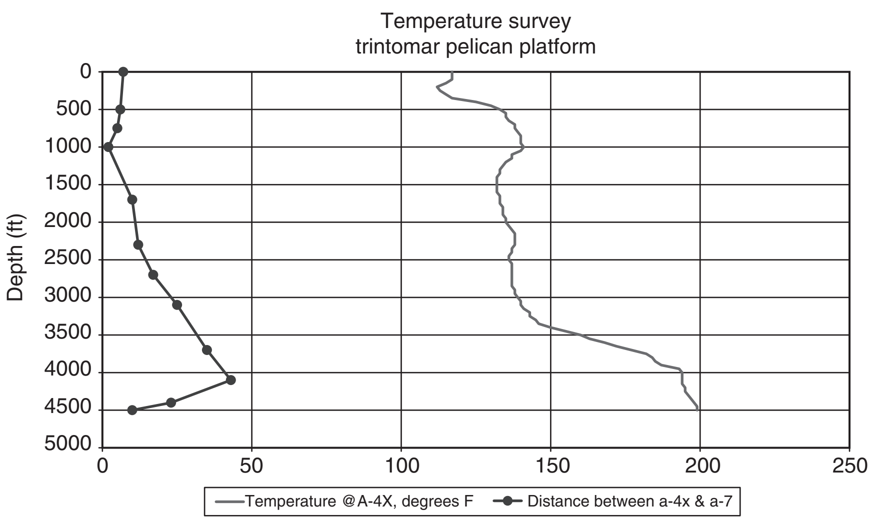


Fig. 8.9 Temperature survey versus distance between Pelican A-4X and A-7.

illustrates the temperature profile in the A-4X overlain by the directional survey analysis of the relative distance between the wellbores.

This figure further confirms the previous pressure and temperature analyses. The greatest distance between the two wells is 45 ft at a depth of 4100 ft. That depth corresponds with the most pronounced anomaly, confirming the conclusion that the thermal primary zone of loss is below 3600 ft.

As illustrated, the wellbores are interpreted to be 2 ft apart at 1000 ft and 5 ft apart at the seabed. Therefore, the temperature anomaly above 1000 ft was interpreted to be the result of the proximity of the two wellbores and not caused by the flow of gas and condensate to zones near the seabed.

Based on the analyses of the surface pressure and the temperature data, it was concluded that working on the platform was not hazardous and that the platform did not have to be abandoned. As further confirmation, no gas or condensate was observed in the sea around the platform at any time during or following the kill operation.

At the Pelican Platform, the surface pressures remained constant. When the surface pressures remain constant, the condition of the wellbore is also constant. However, when the surface pressures fail to remain constant, the conditions in the wellbore are, in all probability, changing and causing the changes in the surface pressures.

Consider an example of an underground blowout at an offshore drilling operation. With only surface casing set, a kick was taken and an underground blowout ensued. The pressures on the drillpipe and annulus stabilized, and analysis pursuant to the previous example confirmed that the loss was into sands safely below the surface casing shoe (Fig. 8.10).

The pressure history is presented as Fig. 8.11. As illustrated, after remaining essentially constant for approximately 30 h, both pressures began to change rapidly and dramatically, which indicated that the conditions in the wellbore were also changing rapidly and dramatically.

The pressure changes were confusing and not readily adaptable to analysis, and several interpretations were possible.

The declining pressures could have indicated that the wellbore was bridging or that the flow was depleting. Further, a change in the composition of the flow could have contributed to the change in the pressures. Finally, a decline in annulus pressure could have been the result of the flow fracturing toward the surface.

In an effort to define the conditions in the wellbore, a more definitive technique was used to determine the precise depth of the loss from the underground blowout. With the well shut-in, seawater was pumped down the annulus at rates sufficient to displace the gas. As illustrated in Fig. 8.12, while pumping, the annulus pressure declined and stabilized. Once the

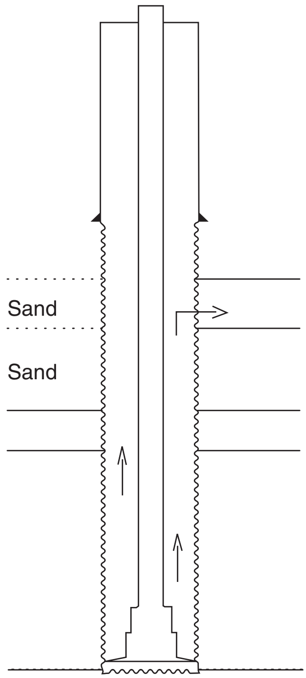


Fig. 8.10 Offshore underground blowout.

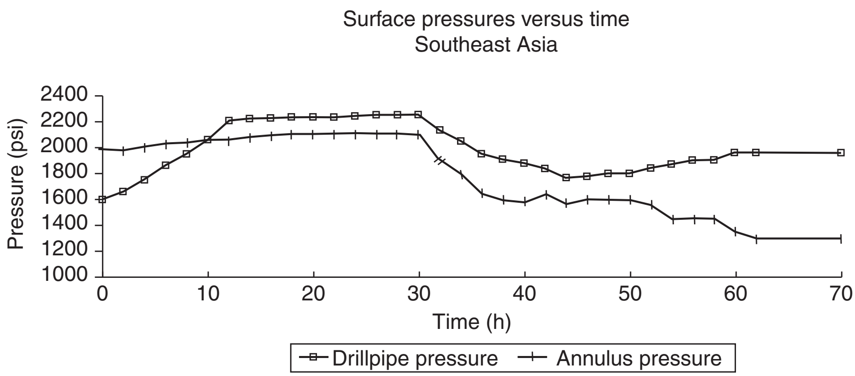


Fig. 8.11 Pressure history from underground blowout in Fig. 8.10.

pumps were stopped, the annulus pressure began to increase. With this data, the depth to the loss zone could be determined using Eq. (8.2):

$$D = \frac{\Delta P}{\rho_{sw} - \rho_f} \tag{8.2}$$

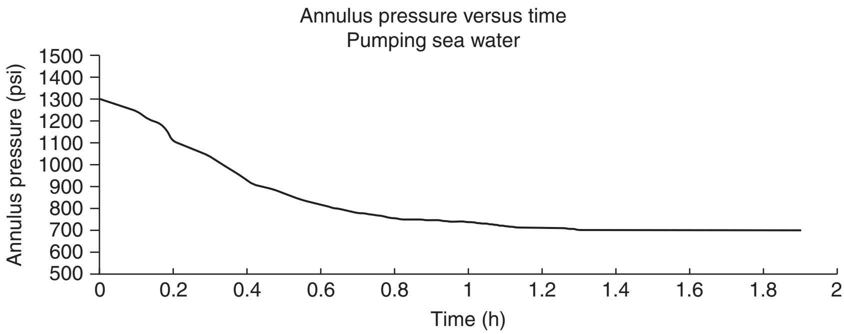


Fig. 8.12 Annulus pressure versus time while pumping sea water.

Consider Example 8.2:

Example 8.2

Given

Seawater gradient, $\rho_{sw} = 0.44$ psi/ft

Gas gradient, $\rho_f = 0.04$ psi/ft

Seawater is pumped into the well shown in Fig. 8.13 and the surface pressure declines from 1500 to 900 psi.

Required

The depth to the zone of loss.

Solution

The depth to the zone of loss is given by Eq. 8.2:

$$D = \frac{\Delta P}{\rho_{sw} - \rho_f}$$

$$D = \frac{600}{0.44 - 0.04}$$

$$D = \mathbf{1500\,ft}$$

As illustrated in Example 8.2, replacing the hydrostatic column of wellbore fluids from the zone of loss to the surface with a hydrostatic column of seawater only reduced the surface pressure by 600 psi. Therefore, the length of the column of seawater between the surface and the zone of loss could be only 1500 ft, which would be 1000 ft higher than the surface casing shoe. The obvious conclusion would be that the flow was fracturing to the surface. Continuing to work on the location would not be safe. In the

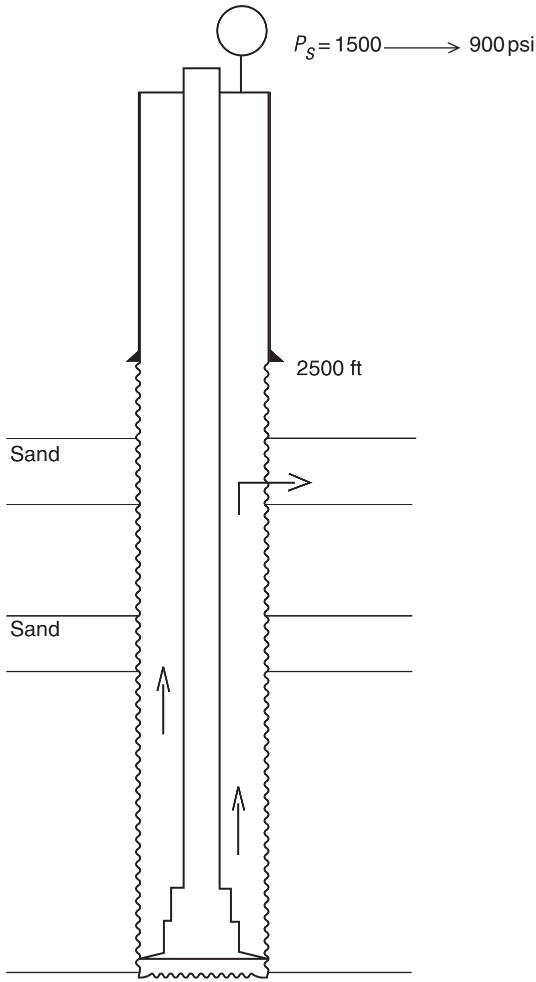


Fig. 8.13 Offshore underground blowout.

actual situation, the flow fractured to the seafloor beneath the rig the following day.

In hard rocks, the flow may fracture to the surface at any point. At the Apache Key, shown in Fig. 8.14, the well cratered at the wellhead. In the Sahara Desert near the community of Rhourde Nouss, Algeria, the flow cratered a water well 127 m away from the well (Fig. 8.15). It is not uncommon in desert environments for the flow to surface in numerous random locations. It is equally common for the gas to percolate through the sand.

Fig. 8.14 Apache Key well cratered at the wellhead.

Fig. 8.15 Well cratered at a water well 127 m away in Algeria.

At Rhourde Nouss, the hot gas would autoignite when it reached the desert floor, producing an eerie blue glow and small fires in the sand (Fig. 8.16).

The wellbore configuration at Rhourde Nouss is illustrated in Fig. 8.17. It was critical to know the location of the holes in the tubulars. Since there was flow to the surface, holes had to be present in the 5 in. tubing, $9\frac{5}{8}$ in.

Fig. 8.16 Fires coming from desert sand in Algeria.

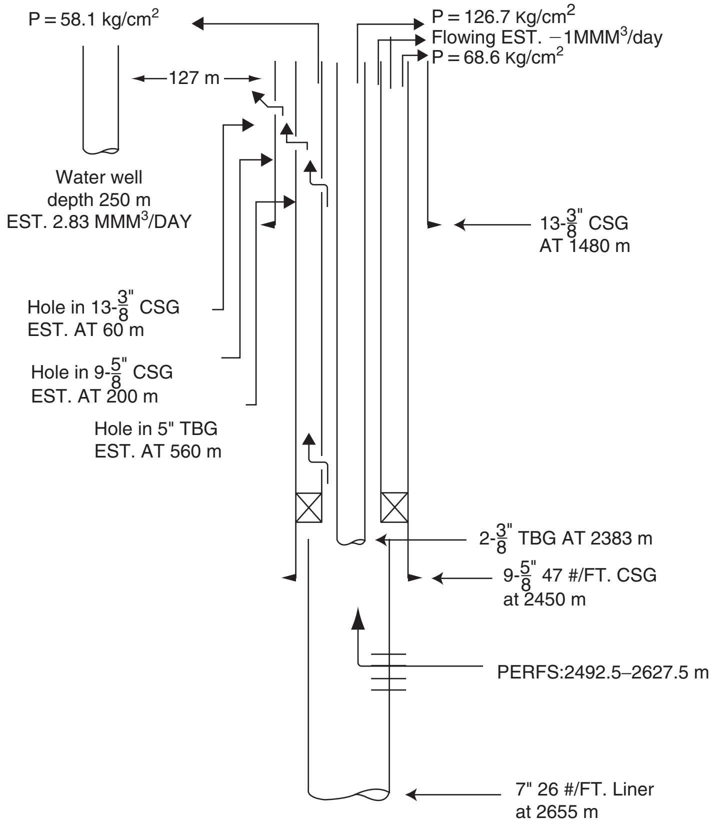


Fig. 8.17 RN-36 blowout, Jun. 24, 1989.

casing, and $13\frac{3}{8}$ in. casing. A temperature survey run in the $2\frac{3}{8}$ in. tubing, which had been run into the well in a kill attempt, is illustrated in Fig. 8.18.

As can be seen, the temperature survey is not definitive. Often a change in temperature or delta temperature can be definitive when the temperature survey alone is not. The delta temperature survey is usually plotted as the change in temperature over a 100 ft interval. The delta survey is then compared with the normal geothermal gradient, which is usually 1.0–1.5 degrees per 100 ft. A greater change than normal denotes a problem area.

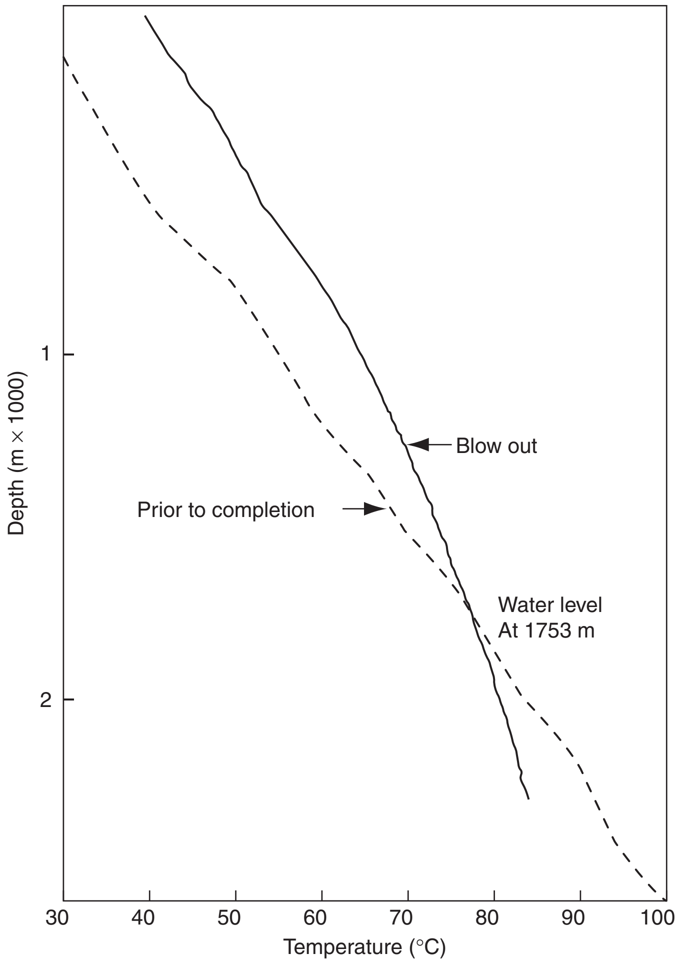


Fig. 8.18 Temperature survey comparison.

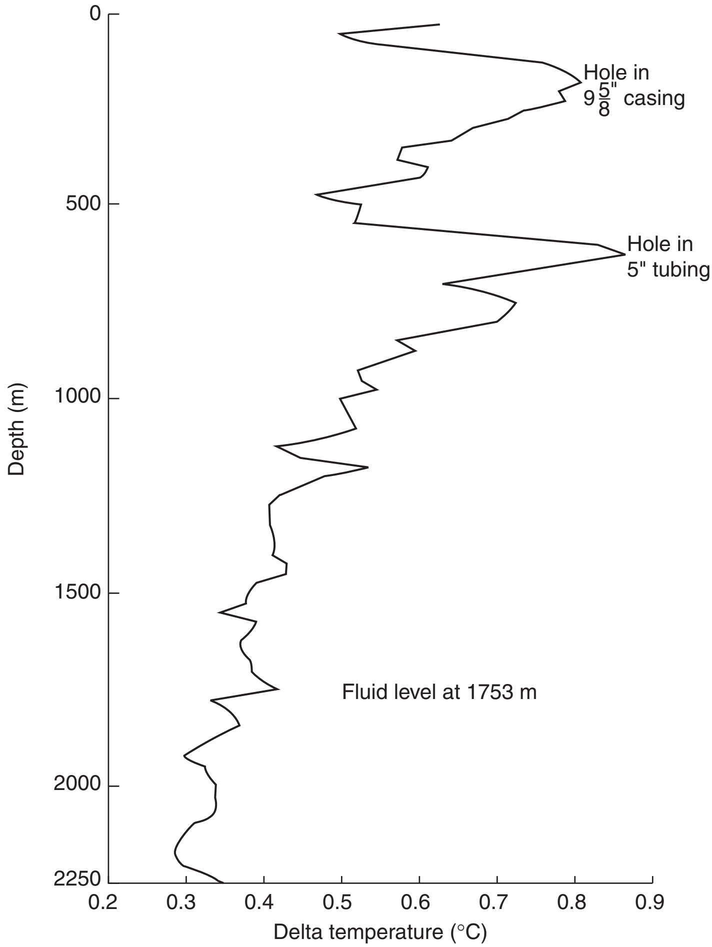


Fig. 8.19 Delta temperature versus depth.

At Rhourde Nouss, when the change in temperature as presented in Fig. 8.19 was analyzed, the tubular failures became apparent. The hole in the $5\frac{1}{2}$ in. tubing is the dominant anomaly at 560 m. The holes in the $9\frac{5}{8}$ in. casing and the $13\frac{3}{8}$ in. casing are defined by the anomaly at 200 m and 60 m, respectively.

PIPE BELOW 4000 FEET

With pipe set below 4000 ft, there is no reported instance of fracturing to the surface from the casing shoe. There are instances of fracturing to the surface after the casing strings have ruptured. Therefore, maximum permissible casing pressures must be established immediately and honored. The maximum annulus pressure at the surface will be the fracture pressure at the shoe less the hydrostatic column of gas.

The wellbore schematic for the Amerada Hess Mil-Vid #3 is presented as Fig. 8.20. An underground blowout followed a kick at 13,126 ft. The 5 in. drillpipe parted at the $9\frac{5}{8}$ in. casing shoe at 8730 ft. During the fishing operations that followed, a temperature survey was run inside the fishing string.

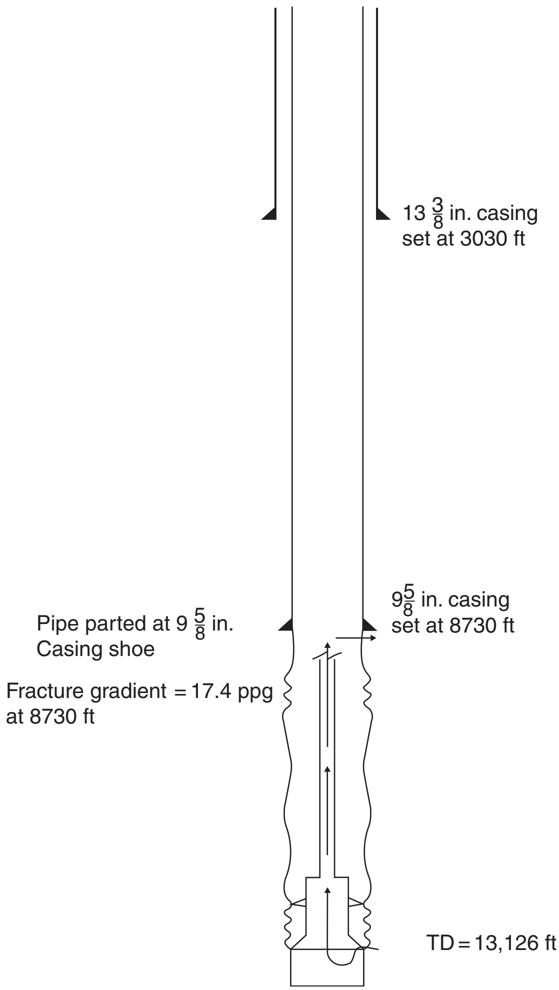


Fig. 8.20 Amerada Hess Mil-Vid #3.

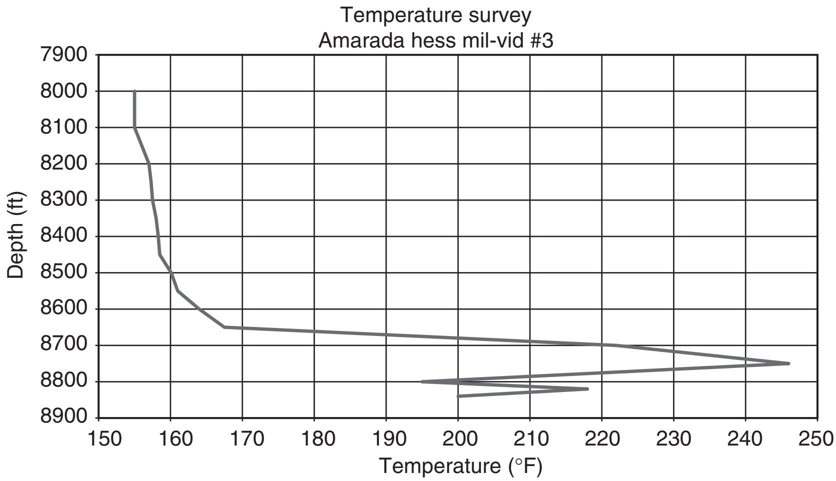


Fig. 8.21 Temperature survey showing an underground blowout in the Mil-Vid #3.

The temperature survey is presented as Fig. 8.21. The 85 degree temperature anomaly at 8700 ft confirmed the underground blowout. It is interesting to note that the temperature decreased below the top of the drillpipe fish at 8730 ft. This anomaly established that the flow was through the drillpipe and that the annulus had bridged.

It is equally interesting that numerous noise logs run in the same time period failed to detect the underground flow. The noise log run on the Mil-Vid #3 is presented as Fig. 8.22.

The fracture gradient was measured during drilling to be 0.9 psi/ft. At offset wells, the gas gradient was measured to be 0.190 psi/ft. Utilizing this

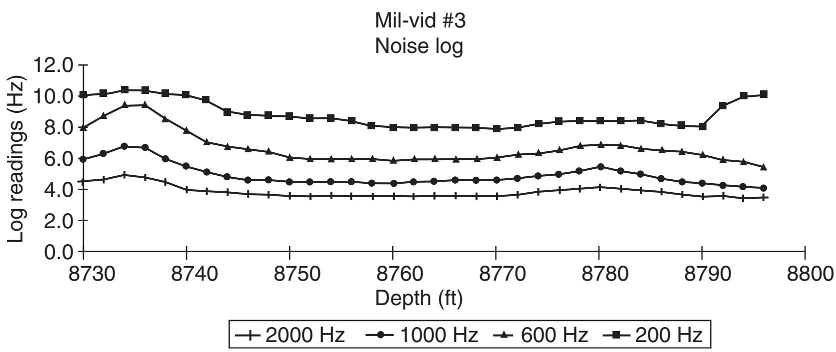


Fig. 8.22 Noise logs from the Mil-Vid #3.

data, the maximum anticipated surface pressure was determined using Eq. (8.3):

$$
\begin{aligned}
P_{\max} &= \left(F_g - \rho_f\right)D \\
P_{\max} &= (0.90 - 0.19)8730 \\
P_{\max} &= \mathbf{6198\ psi}
\end{aligned}
\tag{8.3}
$$

Although the calculated maximum anticipated surface pressure was only 6200 psi, during subsequent operations, the surface pressure was as high as 8000 psi, indicating that the zone of loss was being charged and pressured. Therefore, the actual surface pressure could be much more than the calculated maximum, depending on the volume of flow and the character of the zone of loss.

Once the maximum anticipated surface pressure has been determined, there are three alternatives. The well can remain shut-in, provided there is no concern for the integrity of the tubulars. If the pressure is higher than can be tolerated, the well can be vented at the surface, provided that the surface facilities have been properly constructed. Finally, mud or water can be pumped down the annulus to maintain the pressure at acceptable values.

Since the anticipated surface pressures were unacceptable and the Mil-Vid #3 was located within the town of Vidor, Texas, the only alternative was to pump mud continuously into the drillpipe annulus. Accordingly, 16–20 ppg mud was pumped continuously down the drillpipe annulus for more than 30 days—an expensive but necessary operation. However, the surface pressures were maintained below an acceptable 1000 psi.

For another comparison between the noise log interpretation and the temperature survey, consider the well control problem at the Thermal Exploration Sagebrush No. 42-26 located in Sweetwater County, Wyoming. The wellbore schematic is presented as Fig. 8.23. During drilling at approximately 12,230 ft, a kick was taken, the well was shut-in, and an underground blowout ensued. Water flows from intervals above 4000 ft further complicated analysis.

In an effort to understand the problem, a temperature survey was run and is presented as Fig. 8.24. As illustrated in Fig. 8.24, the temperature gradient between the top of the drill collars at 11,700 ft and 5570 ft was normal at 1.25 degrees per 100 ft. With a normal gradient, it is conclusive that there can be no flow from the interval at 12,230 ft to any interval in the hole. The significant drop in temperature at 5570 ft indicated that the well was flowing from this depth or that a lost circulation zone was at this depth. The

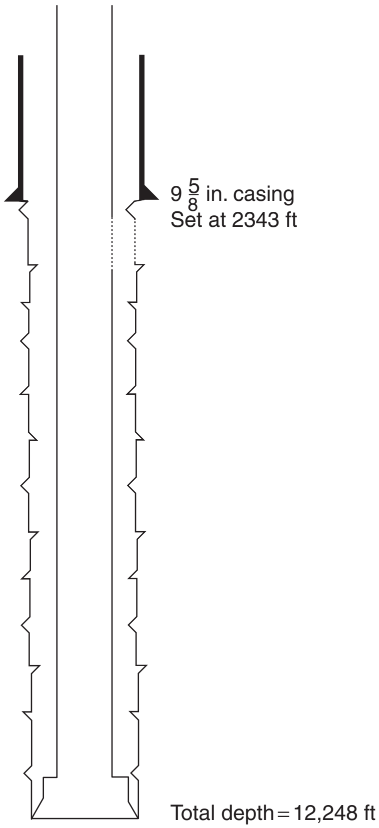


Fig. 8.23 Thermal exploration—Sagebrush 42-26, Sweetwater County, Wyoming.

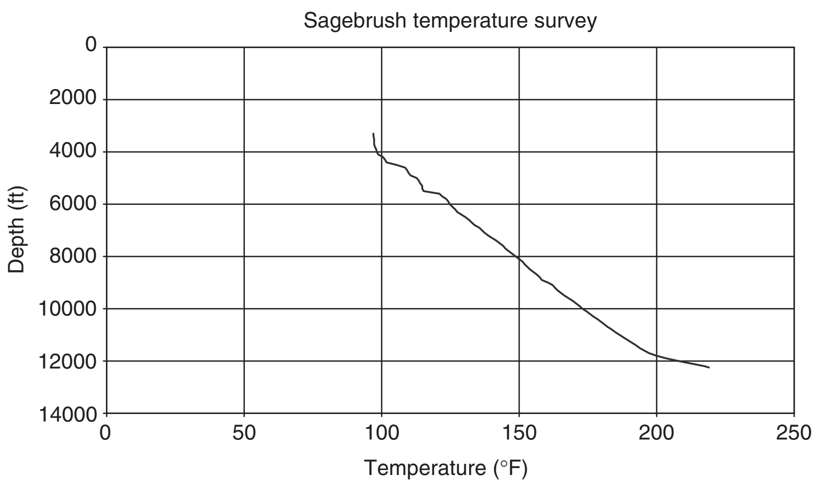


Fig. 8.24 Temperature survey from the Sagebrush 42-26 well.

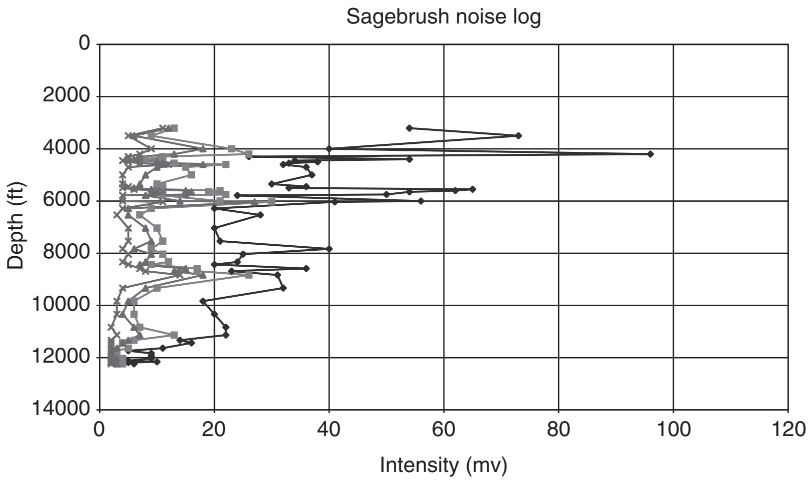


Fig. 8.25 Noise log from the Sagebrush 42-26 well.

temperature survey was conclusive that the well was flowing above 4000 ft since the gradient above this point is essentially zero.

The noise log is presented as Fig. 8.25. As illustrated in Fig. 8.25, noise anomalies are indicated at 4000 ft and 6000 ft, which correspond to the temperature interpretation that fluid was moving at these depths. However, in addition, the noise log was interpreted to indicate flow from 12,000 ft to 7500 ft, which was in conflict with the interpretation of the temperature survey. Subsequent operations proved conclusively that there was no flow from the bottom of the hole at the time that these logs were run.

A deep well in Leon County, Texas, is an interesting and instructive case history. The wellbore schematic is presented as Fig. 8.26. An unanticipated sand at 14,975 ft caused a kick, resulting in an underground blowout. After the initial kill attempt with the rig pumps, a noise log was run. The service provider's interpretation of the noise log was that there was no longer an underground flow.

In an effort to further define the situation, a temperature survey was run and is presented as Fig. 8.27 (1st blowout). The temperature log was conclusive. The underground blowout was continuing from bottom into a zone at approximately 11,000 ft. A second temperature survey, also presented in Fig. 8.27 (after kill) indicated the second kill attempt was successful and the drill string was cemented to approximately 13,000 ft. In this instance, it is conclusive that the temperature survey was definitive and the noise log was in error.

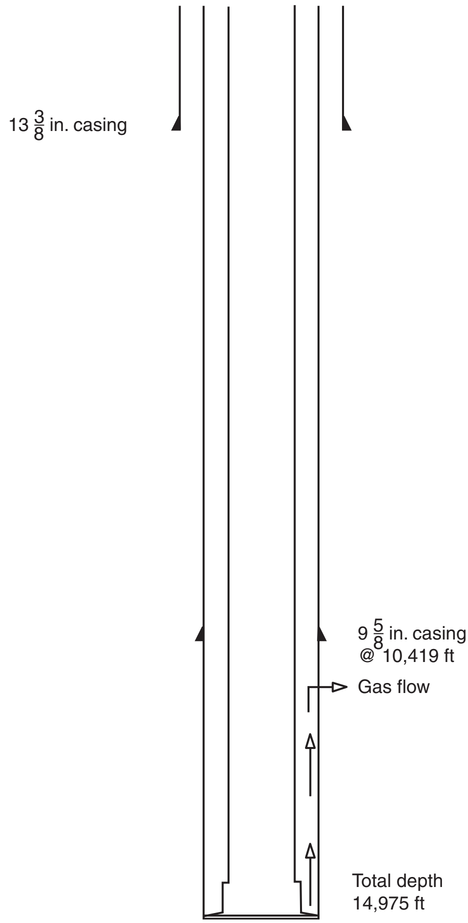


Fig. 8.26 First underground blowout wellbore schematic, Leon County, Texas.

Subsequently, a plug was set at 14,708 ft in the drill collars and the drillpipe was perforated at 10,600 ft. The well was circulated without incident. A severing charge was then fired at 12,412 ft. Immediately after the severing charge was fired, the well began to flow and the underground blowout resumed.

At that time, the primary question was whether the flow was in the annulus or through the drill string. An accurate model of the flow path was vital if alternatives were to be determined and evaluated. Since the severing tool failed to sever the drillpipe, further wireline work could be conducted.

Accordingly, another temperature survey was run and is presented in Fig. 8.27 (2nd blowout). As illustrated, the temperature at the charged zone

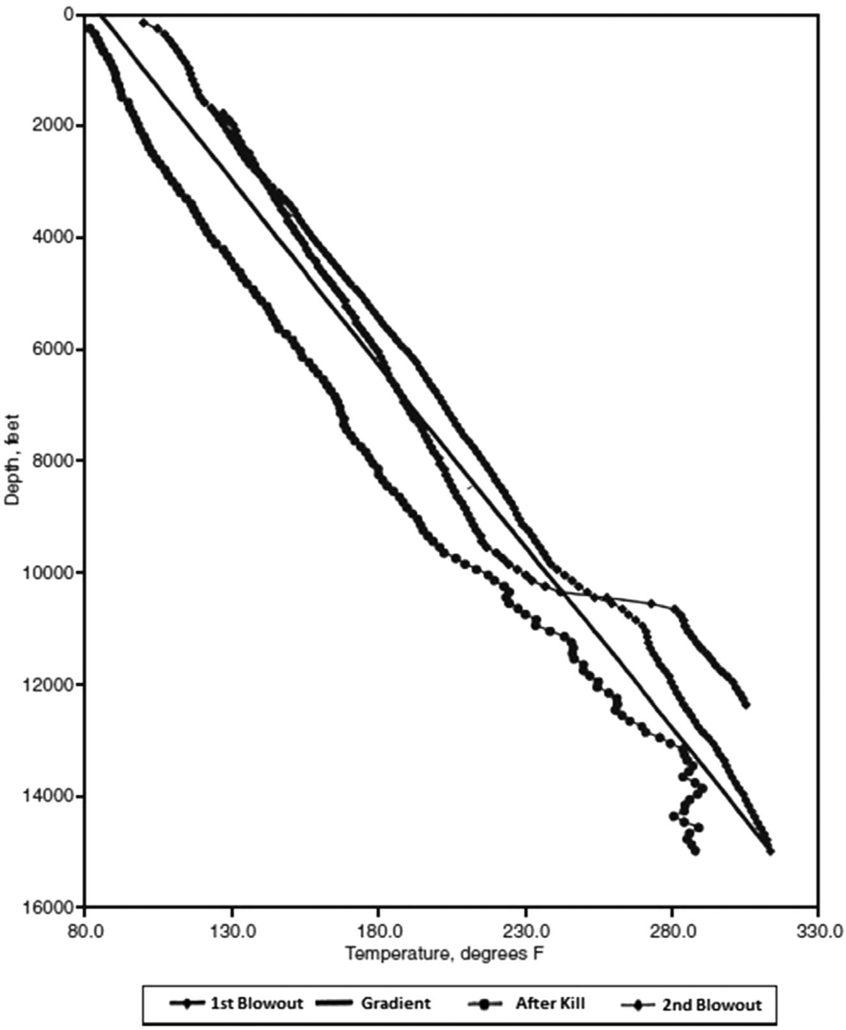


Fig. 8.27 Temperature profiles, Leon County, Texas, February 1998.

was significantly greater than previously recorded. It was logical that since the temperatures were different than previously recorded, the condition of the well must be different. It was further reasoned that since the temperature was significantly hotter in and below the charge zone than anything previously recorded, the measuring device had to be directly in the flow, which meant that the flow path had to be up the drill string as opposed to up the annulus. Based on these interpretations, it was concluded that

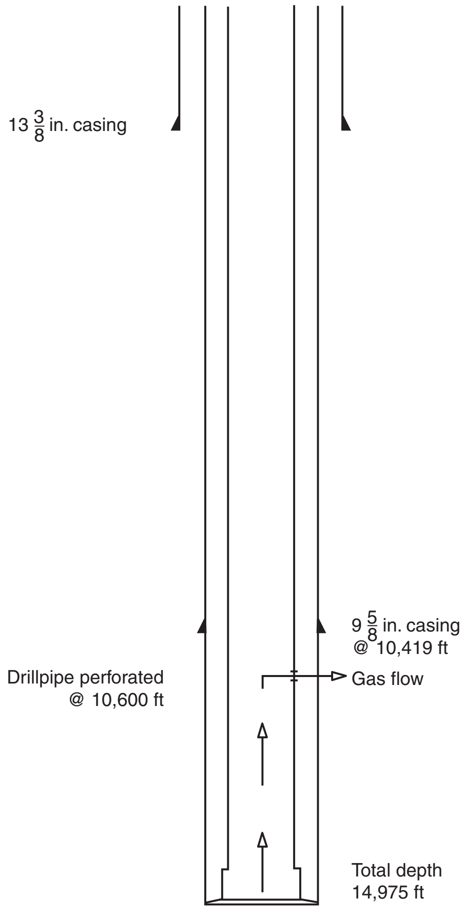


Fig. 8.28 Second underground blowout wellbore schematic, Leon County, Texas.

the flow was as depicted in Fig. 8.28. The well was controlled by setting additional plugs inside the heavyweight drillpipe.

CHARGED INTERVALS—CLOSE ORDER SEISMIC—VENT WELLS

In underground blowouts, the charging of the zone of loss is an important consideration for relief well operations. A relief well located within the charged interval will encounter the charged interval and experience well control problems. The mud weight required to control the charged interval can approach 1 psi/ft, which usually exceeds the fracture gradient of the intervals immediately above and below the zone of loss. Therefore, the relief well can be lost or another casing string can become a necessity.

In addition, the charging of the zone of loss is an important consideration in analyzing the potential for the influx to fracture to the surface. Nowhere is the question of shallow charging more important than offshore.

In late September 1984, Mobil experienced a major blowout at its N-91 West Venture gas field, offshore Nova Scotia, Canada. A relief well, the B-92, was spudded approximately 3000 ft from the blowout. During drilling at 2350 ft with conductor set at 635 ft, a gas kick was taken. The gas zone encountered was the result of the charging caused by the N-91 blowout. A shallow seismic survey was conducted to assist in defining the extent of the underground charging. Booth reported that, when the seismic data was compared with the original work, two new seismic events had been identified [1].

The deeper event occurred at about 2200–2300 ft, which corresponded to the charged zone in the relief well. However, there was also a second event at approximately 1370–1480 ft. The upper interval was interpreted to be approximately 3300 ft in diameter emanating from the N-91. This event was of great concern since only unconsolidated sandstones, gravels, and clays were present between the charged interval and the ocean floor 1100 ft away.

Fortunately, the charged interval never fractured to the surface. Eight additional surveys were conducted between Nov. 5, 1984 and May 9, 1985. Those surveys revealed that the gas in the shallow zone had not grown significantly since the first survey and had migrated only slightly up dip. In addition, the surveys were vital for the selection of safe areas for relief well operations. Finally, the surveys were vital in analyzing the safety and potential hazard of continuing operations onboard the Zapata Scotain with the rig on the blowout.

In the past, it has been customary to drill vent wells into the charged zones in an effort to reduce the charging. Generally, such efforts have not proved successful. The zones of loss are normally not good-quality reservoir. Therefore, the amount of gas being lost greatly exceeds that recovered from the vent wells. The result is that the charging is relatively unaffected by the vent wells.

At the TXO Marshall, for example, three vent wells were completed. The blowout was discovered to be losing approximately 15 mmscfpd underground. The three vent wells were producing a total of less than 2 mmscfpd. Experiences such as this are commonly reported.

If charging is a problem, the better alternative may be to vent the blowout at the surface. If charging is to be affected, the volume of gas vented would have to be sufficient to cause the flowing surface pressure to be less than the shut-in surface pressure plus the frictional losses between the zone of loss and the surface. Once the charging is stopped, the operations at the surface can be conducted safely and the relief well, if necessary, can be in the most expeditious position.

SHEAR RAMS

If shear rams have been used, the situation is very similar to that at the Mil-Vid #3 in that the drillpipe has been severed immediately below the shear rams and the flow is usually through the drillpipe, down the drillpipe annulus, and into the formations below the shoe.

A typical example is illustrated in Fig. 8.29. As illustrated, when the shear rams are used, the result is often very similar to setting pipe and completing for production. If flow is only through the annulus, the well will often bridge, especially offshore in younger rocks which are more unstable. With pipe set and open to the shoe, the flow can continue indefinitely. Shear rams should be used only as a last resort.

CEMENT AND BARITE PLUGS

Generally, when an underground blowout occurs, the impulse is to start pumping cement or setting barite pills. Cement can cause terminal damage to the well. At least, such indiscriminate actions can result in deterioration of the condition of the well. It is usually preferable to bring the blowout under control prior to pumping cement. If the problem is not solved, when the cement sets, access to the blowout interval can be lost. Cement should not be considered under most circumstances until the well is under control or in those instances when it is certain that the cement will control the well.

Barite pills can be fatal or cause the condition of the wellbore to deteriorate. A barite pill is simply barite, water, and thinner mixed to approximately 18 ppg. Each mixture can demonstrate different properties and should be pilot-tested to insure proper settling. Intuitively, the heavier, the better for a barite pill. However, consider Fig. 8.30. As illustrated, for this particular mixture, barite pills ranging in weight from 14 ppg to 18 ppg would permit the barite to settle.

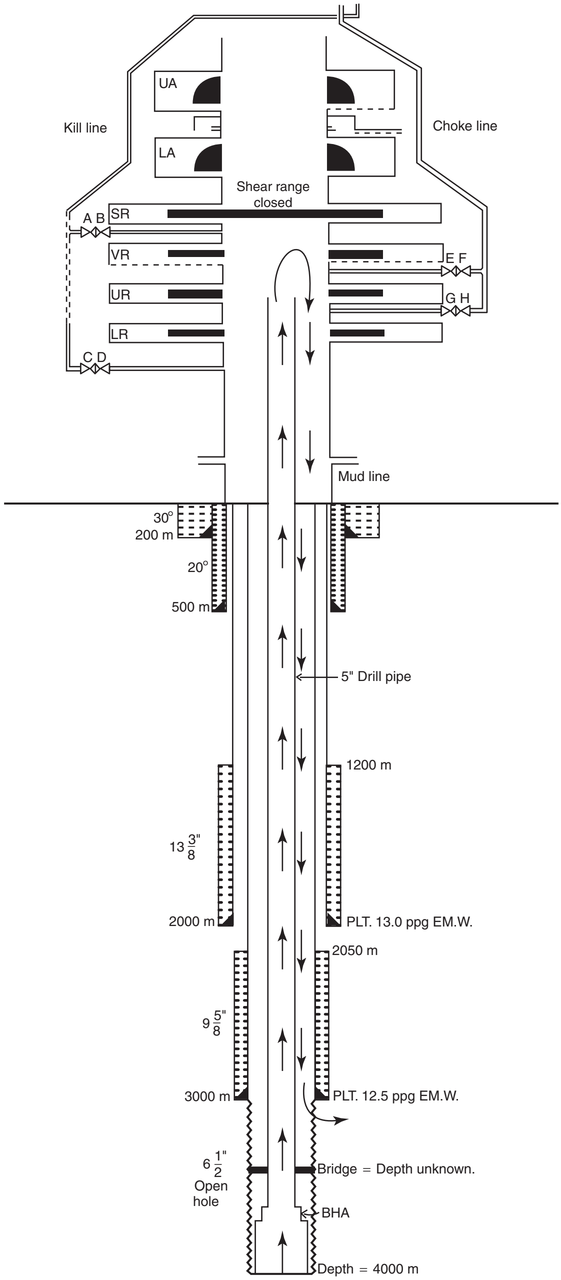


Fig. 8.29 Potential underground blowout with shear rams closed.

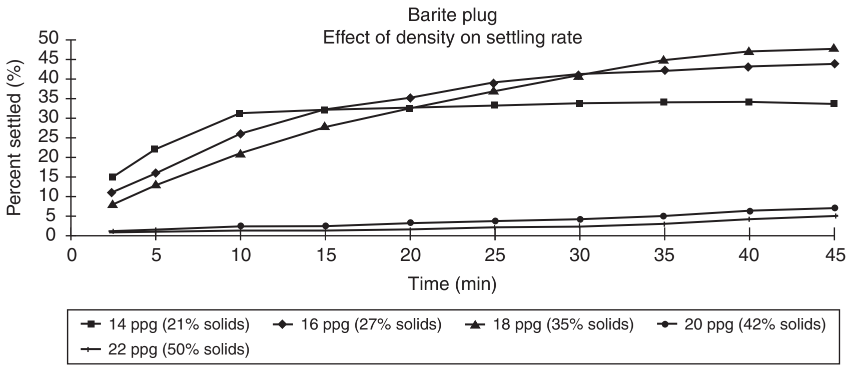


Fig. 8.30 Settling rate for different density barite plugs.

Mixtures above 20 ppg failed, though, to settle barite. The failure to settle is caused by the interaction of the barite particles. All mixtures can attain a density that will not permit the settling of barite. When setting a barite pill, the total hydrostatic does not have to exceed the reservoir pressure for the barite pill to be successful. However, the greatest success is experienced when the total hydrostatic does exceed the reservoir pressure.

When barite or cement is chosen, the drill string should be sacrificed. Attempting to pull the drill string out of a cement plug or barite pill only retards the setting of the cement or the settling of the barite.

Too often, cement plugs and barite pills only complicate well control problems. For example, in one instance in East Texas, the improper use of cement resulted in the loss of the well and a relief well had to be drilled. In another instance offshore, the barite pill settled on the drillpipe as it was being pulled and the drillpipe parted, causing loss of the well. In both instances, millions of dollars were lost due to the unfortunate selection of barite and cement.

REFERENCE

[1] Booth J. Use of shallow seismic data in relief well planning. World Oil 1990;210(5):39 May.

CHAPTER NINE

Case Study: The E. N. Ross No. 2

5 December

2300 hours—set liner and liner packer. Pressure tested to 2000 psi and held for 15 min. Test successful.

6 December

0600 hours—finished laying down drillpipe.

1100 hours—nippling down blowout preventers. Well burped. Thought to be trapped air. Continued to nipple down.

1120 hours—Well burped a second time. Realized there was something wrong. Burps continued about every half hour.

1200 hours—burps began to hit the rig floor.

1330 hours—burps hitting the blocks which were 30 ft over the floor.

1500 hours—burps going over the crown.

1530 hours—felt the ground shake. Everyone ran. Abandoned location.

This case study of the blowout at the E. N. Ross No. 2 in Rankin County, Mississippi, offers a unique opportunity to understand many of the concepts discussed in this text from the perspective of the future and ultimate consequences. These analyses, evaluations, and commentary are intended to be instructive. Several differences of opinion are not presented. Interpretations of events are presented solely for the purpose of consideration and instruction. Nothing presented in this text is intended as a criticism of any operation conducted at the well. Certainly, those involved did not have the luxury of hindsight. The sole purpose of this chapter is to illustrate how the concepts and tools presented in this text can be used to assist in analyzing events and alternatives.

The E. N. Ross No. 2 was spudded on Feb. 17, 1985. It was intended as a 19,600 ft Smackover development well in the Johns Field in Rankin County, Mississippi. Thirteen and three-eighths-in casing was set at 5465 ft, $9\frac{5}{8}$ in. casing at 14,319 ft and a $7\frac{5}{8}$ in. liner at 18,245 ft with the top of the liner at 13,927 ft.

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With the exception of 1644 ft of 47 lb/ft S-95 from 7335 to 8979 ft, the $9\frac{5}{8}$ in. casing consisted of 53.5 lb/ft S-95. The 47 lb/ft S-95 was run as a "weak link" so that, in the event of excessive pressure on the wellbore, a casing failure would more likely occur below 7335 ft instead of at the surface. It was reasoned that, with the failure below 7335 ft, any deadly sour-gas would most likely vent underground.

The Smackover was topped at approximately 18,750 ft and is well known to be an abnormally pressured, sour-gas reservoir containing approximately 30% hydrogen sulfide and 4% carbon dioxide. A 17.4 ppg oil-based mud was used. A trip was made at 19,419 ft for a new bit. An insert bit was to follow two diamond bits. On Jun. 10, 1985, on the trip in the hole with the new insert bit, the drill string became stuck with the bit at 19,410 ft.

Reported problems with the filter cake of the oil mud and the report that the pipe became stuck while sitting in the slips during a connection influenced the conclusion that the string was differentially stuck. Based upon the conclusion that the drill string was differentially stuck, it was decided to attempt to free the fish with a drill stem test (DST) tool. Accordingly, the string was backed off at 18,046 ft, which was 199 ft inside the $7\frac{5}{8}$ in. liner, leaving 1094 ft of spiral drill collars, stabilizers, and drill pipe. The wellbore schematic prior to commencing fishing operations is presented as Fig. 9.1. Pursuant to the cement bond log, the top of the cement behind the $9\frac{5}{8}$ in. casing was at 850 ft.

The first DST tool with an overshot on bottom failed to open. The mud inside the drill pipe was reversed. However, the overshot could not be released. After several hours of the overshot and packer assembly being worked, the string came free and was tripped out of the hole. When the DST tool was inspected on the rig floor, it was discovered that the bottom half of the packer, two subs, and the overshot were lost in the hole, which further complicated the fishing effort.

A taper tap was run without success. A mill was run, and 2.5 ft was milled in 3 h. On Jun. 10, 1985, a second DST tool with a 2 in. spear was run. The drill string was filled to within 13 bbl of capacity with 100 bbl of 17.4 ppg oil-based mud followed by water, which brought the fluid level to approximately 800 ft from the surface. It was reported that the tool was opened, the well flowed for 1 min, and an unrecorded quantity of fresh water was flowed to the surface. The fluid in the drill pipe was reverse-circulated to the surface. The hole was circulated conventionally. The density of the mud recovered from the bottom of the hole was gas cut from 17.4 to 17.1 ppg. The DST tool

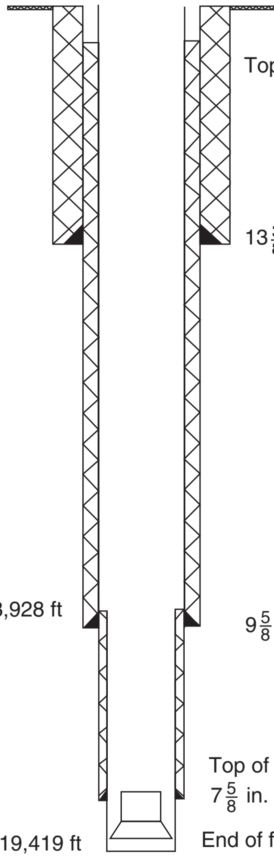

Fig. 9.1 Conditions prior to fishing.

was tripped out of the hole, and the blind rams were closed. Approximately 9 in. of the spear was not recovered.

The DST tool was laid down, and an overshot was picked up. The changing of the bottom-hole assembly required approximately 2 h. When the blind rams were opened, the well was flowing a small stream of mud.

With the well flowing, the bottom-hole assembly consisting of the overshot, seven $4\frac{3}{4}$ in. drill collars, three stands of $3\frac{1}{2}$ in. drill pipe, and one joint of 5 in. drill pipe were run into the hole, and the well was shut in. An additional 8 bbl of mud were reportedly gained during the time required to run the drill string, and the shut in surface pressure was recorded at 500 psi. The end of the drill string was at 562 ft. The well was circulated through the choke with 18.4 ppg mud. After circulating the 18.4 ppg mud, the well was shut in, and the shut in surface pressure was 3000 psi. The gain increased by approximately 100 bbl.

As the shut in pressure reached 3000 psi, the drill pipe began to move up through the derrick. The choke was opened, and the bottom pipe rams were closed above a tool joint on the 5 in. drill pipe. The choke was once again closed, and the shut in surface pressure increased to 3250 psi. Attempts to close the safety valve on the kelly were unsuccessful due to the pressure at the surface. Therefore, the choke was opened a final time, the safety valve was closed, and the choke was closed. When the well was finally shut in on Jun. 21, 1985, an estimated maximum total of 260 bbl had been gained, and the shut in surface pressure was 3700 psi.

After the well was shut in and before snubbing operations began, a detailed snubbing procedure was prepared. Basically, the snubbing procedure recommended that the $3\frac{1}{2}$ in. drill pipe be snubbed into the hole in 2000 ft increments. After each 2000 ft increment, the hole was to be circulated with 18.4 ppg mud using the classical wait-and-weight method. That is, the drill pipe would be filled with the 18.4 ppg mud. The casing pressure would be held constant, while the drill pipe pressure was being established. After the drill pipe pressure was established, it would be held constant, while the 18.4 ppg mud was circulated to the surface. It was anticipated that this staging and circulating heavy-mud procedure would reduce the pressure on the $9\frac{5}{8}$ in. casing.

Further, some favored reverse circulating once the overshot was at the top of the fish. Accordingly, the two conventional back-pressure valves in the drill string had to be replaced with a single pump-out, back-pressure valve. The pump-out, back-pressure valve had a small ball and seat that could be pumped out by dropping a ball. Due to its small size, the pump-out, back-pressure valve was also very susceptible to erosion.

At the well site during the period from June 21 until July 13, preparations were made to snub the drill string into the hole. A snubbing unit was rigged up, a 400 ft flare line was laid, and a flow line was laid 1800 ft to the E. N. Ross No. 1. The surface pressure remained relatively constant at 3700 psi for 18 days from June 21 until July 9. From July 9 until July 13, the surface pressure declined to 2600 psi. By the end of the day on July 13, a total of 69 joints had been snubbed into the hole. The end of the work string was at approximately 2139 ft.

On July 14, an additional 60 joints were snubbed into the hole. The end of the work string was at approximately 4494 ft. The hole was circulated with 276 bbl of 18.4 ppg mud pumped in, and 265 bbl of mud recovered pursuant to the snubbing program. The entire operation proceeded without incident, and no gas was observed at the surface. After the 18.4 ppg mud was circulated, the surface pressure stabilized at 2240 psi.

On the morning of July 15, the surface pressure was recorded at 2350 psi. By the end of the day, the work string had been snubbed to 8950 ft, and the surface pressure had stabilized at 2000 psi. The wellbore schematic is illustrated as Fig. 9.2. Two manually operated ball valves were installed in the top of the $3\frac{1}{2}$ in. drill pipe in the work basket. Chicksans and hammer unions were used to connect the pump trucks to the drill pipe as illustrated in Fig. 9.3.

Although the snubbing procedure provided for 2000 ft increments, a total of approximately 4456 ft was run into the well. As provided in the snubbing procedure, circulation was initiated using the classical wait-and-weight procedure. The casing pressure was held constant, while the pump was brought to speed and the drill pipe pressure was established. With the

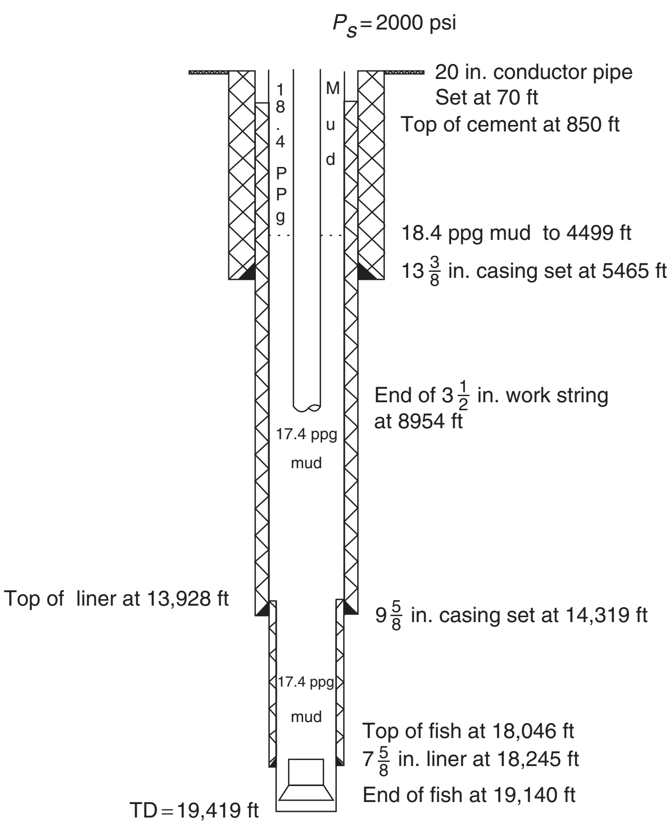

Fig. 9.2 Jul. 15, 1985.

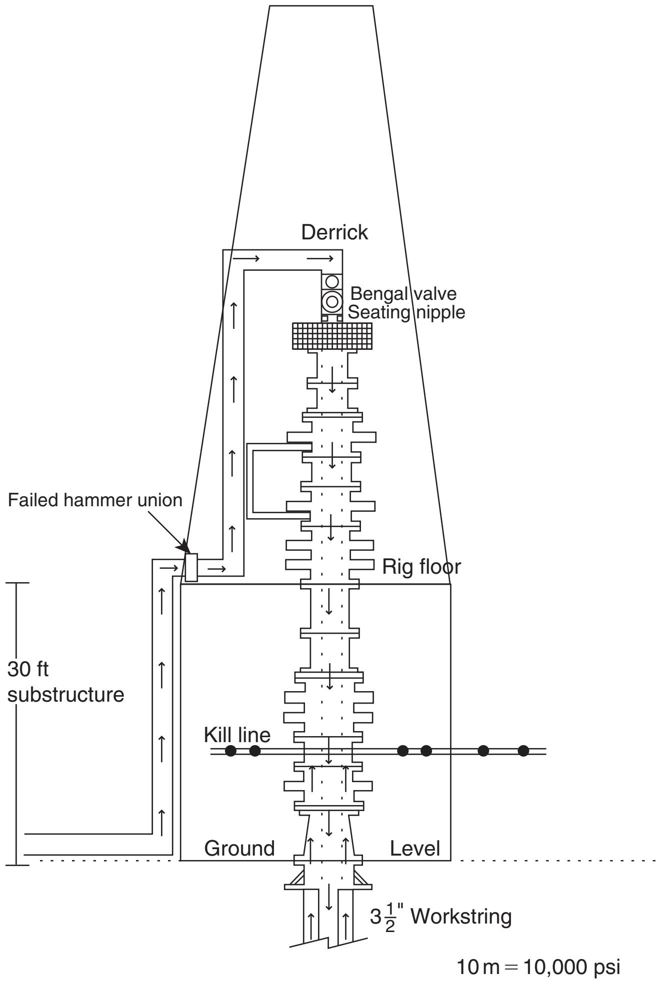

Fig. 9.3 Pump and return lines.

annulus pressure constant at 2000 psi, the drill pipe pressure was recorded to be 2700 psi at 2 bpm and 2990 psi at 3 bpm. Once the drill pipe pressure was established at 2990 psi, circulation commenced with the 18.4 ppg mud being pumped at 3 bpm.

The surface pressures, total barrels pumped, and total barrels recovered are recorded in Table 9.1 and illustrated in Fig. 9.4. As shown in Table 9.1, pumping operations commenced at approximately 1643 hours. Thirty-five barrels were required to fill the drill pipe. At 1727 hours with 120 bbl pumped into the drill pipe, the flow rate from the annulus began to exceed the pump rate, resulting in a net gain in the pits.

Table 9.1 Pumping history, E. N. Ross No. 2, Jul. 15, 1985

Time	Tubing pressure	Casing pressure	Barrels in	Net barrels in	Barrels out	Average rate in	Average rate out	Gain	Remarks
16:43	0	2000	0	0	0	0		0	Tubing at 8958 ft
16:45	0	2000	10	0	0	5.0		0	2 bpm—700 psi
16:48	0	2000	20	0	0	3.3		0	3 bpm—2940 psi
16:52	0	2040	30	0	0	2.5		0	
16:59	2940	2060	40	5	0	1.4		0	
17:03	2880	2200	50	15	0	2.5		0	
17:08	2920	2125	60	25	24	2.0	4.8	−1	
17:12	2940	2150	70	35		2.5	2.5		
17:15	2880	2090	80	45	42	3.3	2.5	−3	
17:18	2880	2040	90	55	55	3.3	4.3	0	
17:22	2900	2010	100	65	65	2.5	2.5	0	18.6 ppg
17:25	2910	1990	110	75	76	3.3	3.6	1	
17:27	2880	1900	120	85	89	5.0	6.5	4	
17:32	2880	1900	130	95	100	2.0	2.2	5	
17:38	2880	1780	150	115	135	3.3	5.8	20	
17:41	2880	1700	160	125	160	3.3	8.3	35	
17:44	3000	1900	170	135	180	3.3	6.6	45	
17:47	3000	1900	180	145		3.3	6.0		
17:50	2920	1900	190	155		3.3	6.0		18.1 ppg
17:53	2940	1925	200	165		3.3	6.0		

Continued

Table 9.1 Pumping history, E. N. Ross No. 2, Jul. 15, 1985—cont'd

Time	Tubing pressure	Casing pressure	Barrels in	Net barrels in	Barrels out	Average rate in	Average rate out	Gain	Remarks
17:57	3040	2100	210	175		2.5	6.0		17.8 ppg
18:00	2940	2200	220	185		3.3	6.0		
18:03	3020	2200	230	195	295	3.3	6.0	100	
18:06	3000	2300	240	205		3.3	4.0		
18:08			247	212	315	3.5	4.0	103	
18:09	3040	2400	250	215		3.0	5.5		
18:10			253	218	326	3.0	5.5	108	17.6 ppg
18:12	2980	2300	260	225		3.5	7.6		
18:13			263	228	349	3.0	7.6	121	
18:15	3040	2500	270	235		3.5	9.3		
18:18	2980	2500	280	245		3.3	9.3		
18:19			282	247	405	2.0	9.3	158	17.5 ppg
18:21	3080	2800	290	255		4.0	14.3		
18:22			294	259	448	4.0	14.3	189	17.4 ppg
18:25	2800	2740	300	265		2.0	10.5		
18:26			302	267	490	2.0	10.5	223	
18:28	2880	2740	310	275		4.0	8.6		
18:31	2980	2820	320	285		3.3	8.6		17.6 ppg
18:35	3040	3300	330	295		2.5	8.6		
18:37			336	301	585	3.0	8.6	284	
18:38	3040	3400	340	305		4.0	6.9		
18:42	3000	3480	350	315		2.5	6.9		
18:45	2960	3575	360	325		3.3	6.9		
18:47	3000	3700	370	335		5.0	6.9		18.2 ppg

18:52	3080	3900	380	345		2.0	6.9		
18:54	2840	3900	390	355		5.0	6.9		18.0 ppg
18:57	2940	3980	400	365		3.3	6.9		
19:01	2800	4100	410	375		2.5	6.9		
19:04	2980	3900	420	385		3.3	6.9		
19:08	2880	4310	430	395		2.5	6.9		
19:12	2900	4590	440	405		2.5	6.9		Good flare
19:15	2980	4700	450	415		3.3	6.9		16.5 ppg
19:19	2900	4750	460	425		2.5	6.9		
19:23	2900	4700	470	435		2.5	6.9		Flared
19:26	2900	4700	480	445	927	3.3	6.9	482	
19:28	3000	4500	490	455		5.0	7.9		
19:31	2990	4600	500	465		3.3	7.9		
19:39	4180	4800	530	495		3.7	7.9		
19:42		5100	540	505	1054	3.3	3.6	549	Shut down
19:55	3780	5000				0.7	3.6		Start over
19:56	5200	5000	550	515		0.7	3.6		
20:03	5200	5000	580	545		4.2	3.6		
20:07	5700	4990	600	565		5.0	3.6		
20:09	6000	4980				3.3	3.6		
20:10	5960	4900	610	575		3.3	3.6		
20:12	6060	4910	620	585		5.0	3.6		
20:13	6100	4940				5.0	3.6		
20:14	6100	4910	630	595		5.0	3.6		
20:15	6300	5000	640	605		10.0	3.6		
20:16	6240	5000				4.3	3.6		

Continued

Table 9.1 Pumping history, E. N. Ross No. 2, Jul. 15, 1985—cont'd

Time	Tubing pressure	Casing pressure	Barrels in	Net barrels in	Barrels out	Average rate in	Average rate out	Gain	Remarks
20:17	6240	4960				4.3	3.6		
20:18	6460	4910	653	618		4.3	3.6		
20:19	6460	4890				8.3	3.6		
20:20	6500	4900				8.3	3.6		
20:21	6280	4990	678	643		8.3	3.6		
20:23	5940	5010	690	655		6.0	3.6		
20:25	5920	4950				3.7	3.6		
20:26	6100	5010				3.7	3.6		
20:27	6100	5000				3.7	3.6		
20:28	6100	4900				3.7	3.6		
20:29	6220	5100				3.7	3.6		
20:30	6220	4990				3.7	3.6		
20:31	6300	5050	720	685		3.7	3.6		
20:33	6360	5000	730	695		5.0	3.6		
20:34	6300	4900				5.0	3.6		
20:35	6400	5000	740	705		5.0	3.6		
20:36	6400	4950				5.0	3.6		
20:37	6560	5010	750	715		5.0	3.6		
20:38	6560	5000				5.0	3.6		
20:39	6650	5004	760	725		5.0	3.6		
20:41	6800	5010	770	735		5.0	3.6		
20:43	6750	5000				3.3	3.6		
20:44	6850		780	745		3.3	3.6		

20:45	6700	4700	790	755		10.0	3.6		
20:46	6750	4790				3.3	3.6		
20:47	6700	4710				3.3	3.6		
20:48	6650	4680	800	765		3.3	3.6		
20:49	6700	4700				5.0	3.6		
20:50	6720	4800	810	775		5.0	3.6		
20:52	6800	4750	820	785		5.0	3.6		
20:53	6700	4610				5.0	3.6		
20:54	6700	4625	830	795		5.0	3.6		
20:55	6740	4650				5.0	3.6		
20:57	6700	4580				5.0	3.6		
20:58	6750	4500	850	815		5.0	3.6		
21:00	6700	4650	860	825	1293	5.0	3.6	468	

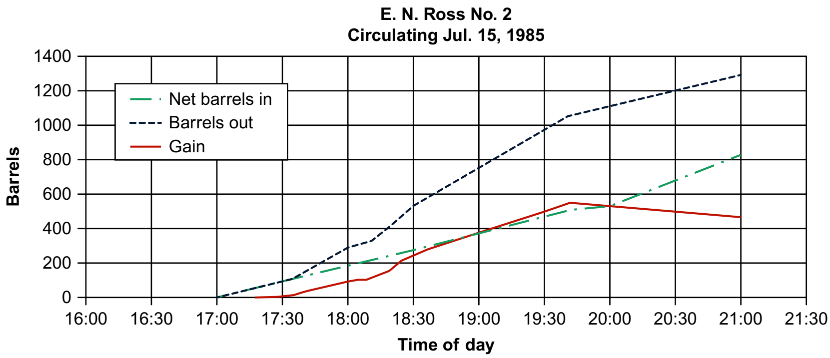

Fig. 9.4 Graphical representation of volume pumped.

At 1854 hours, after 390 bbl was pumped and approximately 725 bbl was recovered, gas was reported at the surface. With the gas to the surface, the net gain was 369 bbl. At 1942 hours, the well was shut in with 5100 psi on the annulus and 4180 psi on the drill pipe. At that time, 540 bbl had been pumped, 1054 bbl had been released from the annulus for a net gain of 549 bbl, and a good flare was reported. The back-pressure valve appeared to be holding.

After the well was observed for 13 min, pumping operations were resumed, and the circulation rate was increased to 6 bbl/min. The annulus pressure was held constant at 5000 psi, and the drill pipe pressure was established at 5200 psi. Contrary to the snubbing procedure, the annulus pressure was held constant at 5000 psi until 2044 hours when the drill pipe pressure reached 6850 psi. The drill pipe pressure was then held constant at approximately 6700 psi. At 2110 hours, a leak developed in a hammer union on the rig floor, and the pump-in line failed. The choke was closed. Flow from the drill pipe not only continued but also increased, indicating that the back-pressure valve was not functioning. Subsequently, three men were carried to the snubbing basket in the crane's personnel basket. Their efforts to close the two ball valves were unsuccessful. The sour-gas alarms sounded. The location was abandoned, the gas was ignited, and the rig was completely destroyed by the fire. The well was subsequently capped and killed. Litigation continued for many years.

ANALYSIS OF THE BLOWOUT

Certainly, there were considerable opportunities for decisions during the course of this operation, and each decision point was clouded with numerous alternatives.

The Drilling and Fishing Operation

Utilizing a DST tool to free differentially stuck pipe was common in shallow, low pressure, or nonhydrocarbon-bearing formations. It was known to have been used on occasion in deep, high-pressure, hydrocarbon-bearing zones. For the operation to be successful, a differential into the wellbore must be created. There was no doubt that the Smackover had been penetrated and that it contained high-pressure sour-gas. Therefore, if the operation was successful, an influx and well control problem could result.

Backing off inside the casing ultimately complicated the situation. Had the DST procedure been successful, any further question would have been moot. The considerations supporting backing off in the casing are valid. That is, it is much easier to engage the fish and set the DST packers in the casing as opposed to the open hole.

Further, as discussed in Chapter 4, the oil-based mud could mask the presence of an influx. No flow or improper filling was detected during the trip out of the hole. According to reports, the hole was properly filled during the trip out.

The Kick

While out of the hole, the crew noticed that the well was flowing and immediately attempted to run the pipe into the hole, a routine and common practice in 1985.

As outlined in Chapter 3, the best procedure is to shut in the well as soon as a kick is detected. Had the crew shut in the well when the flow was observed as the blind rams were opened, the gain and surface pressure would have been minimal.

By this time, a very difficult well control problem was inevitable. With the top of the fish at 18,046 or almost 1400 ft from the bottom of the hole, it was not possible to trip the drill string to bottom and circulate out the influx.

As was common and routine in 1985, when the crew observed the kick, the drill collars and overshot were run along with a small amount of drill pipe. In light of later requirements, it would have been better if the drill string had not been run. The drill collars restrict the pump rate in the event that high kill rates are necessary. Further, with high surface pressures, snubbing the drill collars out of the hole is more difficult. If the drill collars were spiral drill collars, snubbing them out of the hole would have been even more difficult.

When the crew did succeed in running approximately 560 ft of drill string into the well and shutting in the well, the surface pressure was reported to be 500 psi, and the additional gain was only eight barrels. Again, as was common and routine in 1985, the hole was circulated. However, there is insufficient change in density of 560 ft of mud to materially affect the bottom-hole pressure of a 19,419 ft well.

Further, there is no good way to circulate the well when the bit is not on the bottom of the hole. As was discussed in Chapter 4, there is no classical procedure for circulating anywhere except on the bottom of the hole. The U-tube model is only applicable when the bit is on the bottom of the hole. With the bit anywhere other than the bottom of the hole, the U-tube model becomes the Y-tube model, and it is impossible to understand exactly what is occurring in the wellbore. The wait-and-weight method, the driller's Method, and keeping the drill pipe pressure constant are meaningless when the bit is not on the bottom of the hole.

As illustrated in Chapter 4, the hole could be circulated using the constant pit level method. Another name for the constant pit level method is the barrel in—barrel out method. A more descriptive name is the dead well method. These names all describe the manner in which a well is routinely circulated during any drilling operation when an influx is not in the hole.

As outlined in Chapter 4, all things must remain constant when this method is being utilized. Specifically, the pit level, choke size, drill pipe pressure, and annulus pressure must not change, while the well is being circulated. In the event that any of these change, the well must be shut in. In Chapter 2, it was suggested that a change in any of these parameters during a routine drilling operation was a signal that the well must be shut in. The same is true when a kick has been taken. Any change is a signal that the well must be shut in.

The pit level did not remain constant during the time that the well was being circulated. The gain increased from 8 bbl to approximately 100 bbl. When the well was finally shut in, the surface pressure increased from 500 to 3250 psi, and the wellhead force resulting from the shut in surface pressure was sufficient to cause the drill string to be pushed out of the hole. The well had to be opened and allowed to flow, while the tubulars could be secured. When finally shut in, the surface pressure was 3700 psi. The size of the total gain is disputed. For the purpose of this writing, the size of the total gain was determined from pressure analysis to be 260 bbl.

Finally, it will be remembered that a joint of 5 in. drill pipe was run in order that the rams could be closed, as there were no rams in the stack for the $3\frac{1}{2}$ in. drill pipe. As a result of this minor complication, the well had to be frozen in order to remove the 5 in. drill pipe and commence snubbing operations.

The Snubbing Procedure

The snubbing procedure provided that the drill string was to be snubbed into the hole in 2000 ft increments with the well being completely circulated after each 2000 ft increment until reaching "bottom." Further, it was advised that the circulating pressure for each 2000 ft increment would be established by holding the casing pressure constant while bringing the pump to speed and establishing the drill pipe pressure and, thereafter, keeping the drill pipe pressure constant until the new mud was circulated to the surface. Finally, it was anticipated that reverse circulating at "bottom" might be the preferred procedure. Therefore, conventional snubbing wisdom, which dictated that two back-pressure valves be run in the drill string, was abandoned in favor of a single pump-out, back-pressure valve.

In 1985 and today, many involved in well control would have approached this problem in exactly the same manner. However, conceptually, this snubbing procedure contained several theoretical difficulties. As discussed in the previous section and demonstrated by the operations at this well, there is no good way to circulate with an influx when the bit is not on the bottom of the hole. The recommendation to use classical well control procedures to establish the drill pipe pressure and keep the drill pipe pressure constant, while circulating is potentially problematic.

Classical circulating procedures can be successful if there is no influx migration. If the influx migrates, problems can develop. The rising influx can cause the surface pressures to increase. In response, the choke will be opened to keep the drill pipe pressure constant. In that event, additional influx will occur. Remember that, as just discussed, the condition of the well deteriorated when the rig crew circulated at 562 ft.

The techniques introduced in Chapter 4 can be used to illustrate that, theoretically, replacing the 17.4 ppg mud above the influx with 18.4 ppg mud would reduce the maximum pressure at the surface. In addition, theoretically, the techniques can be used to demonstrate that circulating the influx to the surface in 2000 ft increments will reduce the maximum pressure at the surface.

With the $9\frac{5}{8}$ in. 47 lb/ft "weak link" at 7335 ft, it is presumed that the surface pressure will not exceed approximately 5000 psi with the 17.4 ppg mud in the hole even though the $9\frac{5}{8}$ in. casing has been cemented to within 850 ft from the surface. Keeping in mind that the practical considerations render this approach very difficult and, in some instances impossible to accomplish, the theoretical aspects are instructive and interesting to consider. Consider Example 9.1:

Example 9.1

Given:

Figs. 9.5 and 9.6

Specific gravity, $S_g = 0.785$
Gain = 260 bbl
Bottom-hole pressure, $P_b = 16{,}907$ psia
Surface pressure, $P_a = 3700$ psia
Bottom-hole temperature, $T_b = 772$ R
Surface temperature, $T_s = 520$ R
Temperature gradient, $T_{grad} = 1.3°/100$ ft
Compressibility factor, $z_b = 1.988$
$z_s = 1.024$
Gas gradient, $\rho_f = 0.162$ psi/ft
Casing annular capacity, $C_{dpca} = 0.0589$ bbl/ft
Liner annular capacity, $C_{dpla} = 0.0308$ bbl/ft
Top of gas, $TOG = 12{,}385$ ft

Required:

1. The surface pressure with $3\frac{1}{2}$ in. drill pipe on bottom and 17.4-ppg mud
2. The surface pressure with $3\frac{1}{2}$ in. drill pipe on bottom and 18.4-ppg mud
3. The surface pressure with gas to surface in (1)
4. The surface pressure with gas to surface in (2)
5. The surface pressure with gas to the surface if only 2000 ft of influx are circulated out with 17.4 ppg mud.
6. The surface pressure with gas to the surface if only 2000 ft of influx are circulated out with 18.4 ppg mud.

Solution:

1. With pipe at 19,419 ft, the surface pressure with 17.4 ppg mud is

$$P_b = P_s + \rho_f h_b + \rho_m (D - h_b)$$
$$P_s = P_b - \rho_f h_b - \rho_m (D - h_b)$$
$$h_b = D - TOG$$
$$h_b = 19{,}419 - 12{,}385$$
$$h_b = \mathbf{7304\,ft}$$

Example 9.1—cont'd

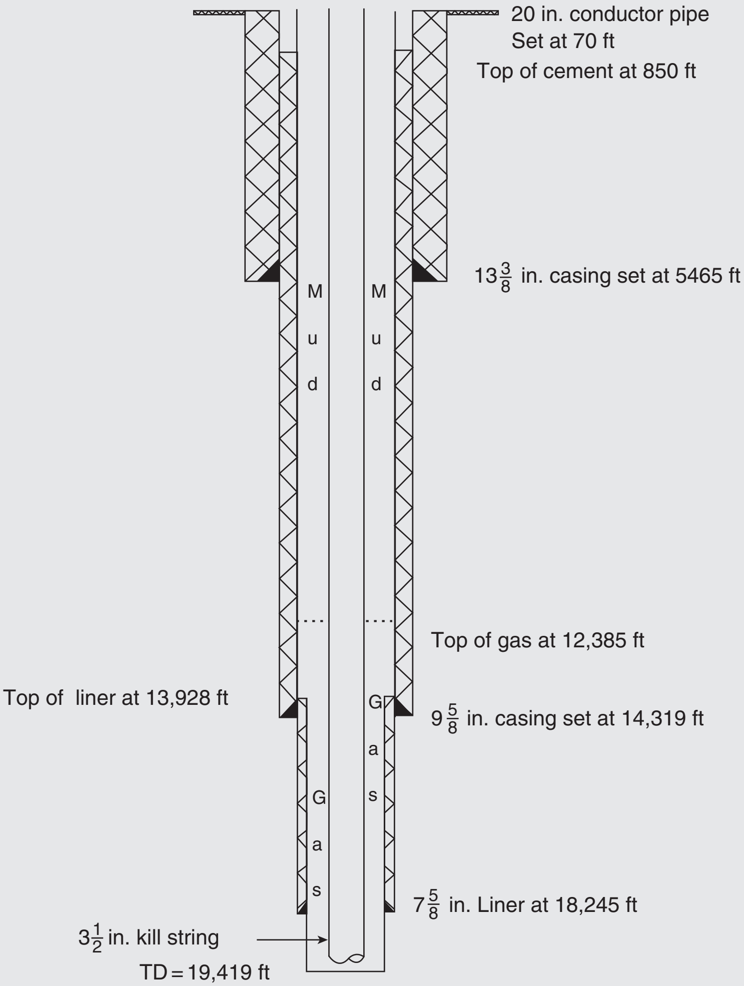

Fig. 9.5 Example 9.1 wellbore schematic.

$$P_s = 16,907 - 0.162(7034) - (0.052)(17.4)(19,419 - 7034)$$
$$P_s = \mathbf{4562\,psi}$$

2. With pipe at 19,419 ft, the surface pressure with 18.4 ppg mud is

$$P_s = 16,907 - 0.162(7034) - (0.052)(18.4)(19,419 - 7034)$$
$$P_s = \mathbf{3918\,psi}$$

Continued

Example 9.1—cont'd

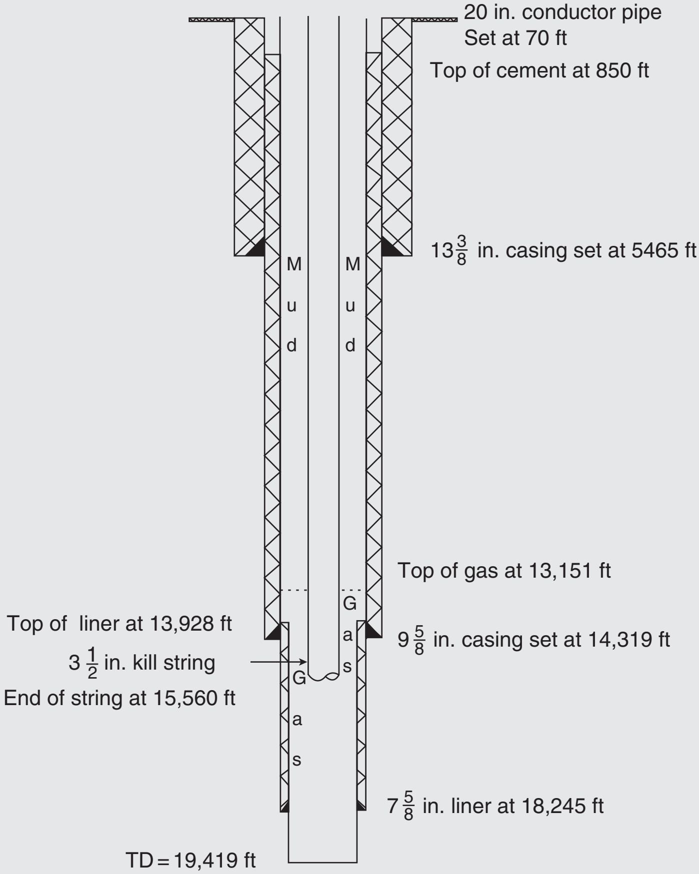

Fig. 9.6 Example 9.1 Part 5.

3. With pipe on bottom at 19,419 ft, the surface pressure with gas to the surface and 17.4 ppg mud is given by Eq. (4.22):

$$P_{xdm} = \frac{B}{2} + \left[\frac{B^2}{4} + \frac{P_b \rho_m z_x T_x h_b A_b}{z_b T_b A_x}\right]^{\frac{1}{2}}$$

$$B = P_b - \rho_m (D - X) - P_f \frac{A_b}{A_x}$$

$$B = 16,907 - 0.9048(19,419 - 0) - (0.162)(7034)$$

$$\times \left(\frac{0.7806(0.0308) + 0.2194(0.0589)}{0.0589}\right) B$$

$$= \mathbf{-1378}$$

Example 9.1—cont'd

$$P_{0dm} = \frac{-1378}{2} + \left[\frac{-1378^2}{4} + \frac{16,907(0.9048)(1.024)(520)(7034)(0.0370)}{1.988(772)(0.0589)}\right]^{\frac{1}{2}}$$
$$P_{0dm} = \mathbf{4202\ psi}$$

4. With pipe on bottom at 19,419 ft, the surface pressure with gas to the surface and 18.4 ppg mud is given by Eq. (4.21):

$$B = 16,907 - 0.9568(19,419 - 0)$$
$$-(0.162)(7034)\left(\frac{0.0370}{0.0589}\right)$$
$$B = \mathbf{-2389}$$

$$P_{0dm} = \frac{-2389}{2} + \left[\frac{-2389^2}{4} + \frac{16,907(0.9568)(1.024)(520)(7034)(0.0370)}{1.988(772)(0.0589)}\right]^{\frac{1}{2}}$$
$$P_{0dm} = \mathbf{3926\ psi}$$

5. The surface pressure with gas to the surface, pipe not on bottom, 17.4 ppg mud, 2000 ft increment of influx, and the following:
234 bbl of gas in liner
26 bbl in intermediate = 368 ft
TOG = 13,560 ft
TOL = 13,928
Maximum depth of pipe = 15,560 ft
Total influx encountered:

$$L_{\text{liner}} = 15,560 - 13,928$$
$$L_{\text{liner}} = \mathbf{1632} \text{ feet in } 7\frac{5}{8} - \text{inch liner}$$
$$L_{\text{casing}} = 13,928 - 13,560$$
$$L_{\text{casing}} = \mathbf{368} \text{ feet in } 9\frac{5}{8} - \text{inch casing}$$
$$I_{\text{tot}} = 1632(0.0428) + 368(0.070)$$
$$I_{\text{tot}} = \mathbf{96\,bbls}$$

The new top of gas, TOG, is then given by

$$\text{TOG} = 13,928 - \left(\frac{96 - 0.0308(1632)}{0.0589}\right)$$
$$\text{TOG} = \mathbf{13,151\ ft}$$

Continued

Example 9.1—cont'd

The new height of the influx, h_b is

$$h_b = 15,560 - 13,151$$
$$h_b = \mathbf{2409\,ft}$$

The new area for the bottom of the influx, A_b, would be

$$A_b = \frac{777}{2409}(0.0589) + \frac{1632}{2409}(0.0308)$$
$$A_b = \mathbf{0.0399}$$

The bottom-hole pressure is

$$P_b = 16,907 - 0.162(19,419 - 15,560)$$
$$p_b = \mathbf{16,282\,psi}$$

The new surface pressure could then be calculated as

$$B = 16,282 - 0.9048(15,560) - 0.162(2409)\left(\frac{0.0399}{0.0589}\right)$$

$$B = \mathbf{1939}$$

$$P_{0dm} = \frac{1939}{2} + \left[\frac{1939^2}{4} + \frac{16,282(0.9048)(1.024)(520)(2409)(0.0399)}{1.988(772)(0.0589)}\right]^{\frac{1}{2}}$$

$$P_{0dm} = \mathbf{4016\,psi}$$

6. The surface pressure with pipe not on bottom with 18.4 ppg mud and the same conditions as (5):

$$B = 16,282 - 0.9568(15,560) - 0.162(2409)\left(\frac{0.0399}{0.0589}\right)$$

$$B = \mathbf{1130}$$

$$P_{0dm} = \frac{1130}{2} + \left[\frac{1130^2}{4} + \frac{16,282(0.9568)(1.024)(520)(2409)(0.0399)}{1.988(772)(0.0589)}\right]^{\frac{1}{2}}$$

$$P_{0dm} = \mathbf{3588\,psi}$$

Example 9.1 assumes that there was no fish in the hole and that it was possible to snub the $3\frac{1}{2}$in. drill pipe to the bottom of the hole at 19,419 ft. As shown in part 1, with the drill string on bottom and 17.4 ppg mud in the hole, the surface pressure would have increased from 3700 to 4562 psi because the influx was longer. As illustrated in part 3, which assumes that the entire influx is circulated to the surface from the bottom of the hole, the surface pressure with gas to the surface would have been only 4202 psi, or 360 psi less than when the influx was on bottom.

According to part 5, if a 2000 ft increment of influx was circulated to the surface with 17.4 ppg mud, the maximum pressure with gas to the surface would have been 4016 psi, which is approximately 200 psi less than that experienced when circulating the entire influx from bottom. As a matter of interest, the surface pressure prior to circulating with the bit at 15,560 ft in part 5 is calculated to be 3996 psi.

By comparison, with the 18.4 ppg mud and the bit on the bottom of the hole, the surface pressure would have been 3918 psi (part 2). If the entire influx was circulated to the surface as assumed in part 4, the maximum surface pressure with gas to the surface would be 3927 psi or about the same as when circulation commenced. If a 2000 ft interval was circulated to the surface as assumed in part 6, the maximum pressure with gas to the surface would have been 3588 psi.

The unusual pressure behavior is due to the presence of the fish, the long $7\frac{5}{8}$ in. liner, and the size of the influx. The influx entirely fills the liner. Therefore, when circulation commences, the influx is immediately circulated into the $9\frac{5}{8}$ in. casing where it is considerably shorter. Consequently, the annulus pressure declines dramatically. As the influx is circulated up the $9\frac{5}{8}$ in. casing to the surface, the annulus pressure increases.

Analysis of Example 9.1 illustrates that the snubbing procedure was theoretically sound in that replacing the 17.4 ppg mud with 18.4 ppg mud would reduce the surface pressure. In addition, the snubbing procedure was theoretically sound in that circulating the influx to the surface in 2000 ft increments would further reduce the surface pressure. The maximum calculated difference would be 3600 psi compared with 4600 psi.

The advantage of the lower pressure must be considered from the operational perspective. That is, the worst-case-scenario surface pressure of 4600 psi is less than the maximum allowable of 5000 psi. Therefore, considering the time, difficulty, and mechanical problems associated with circulating at 2000 ft intervals, circulating at intervals is not the best theoretical alternative.

It must be remembered that there is a theoretical problem in Example 9.1. It was assumed that the 17.4 ppg mud could be replaced by the 18.4 ppg mud and that the influx could be circulated to the surface in 2000 ft increments. There is no theoretically correct procedure to accomplish that that was assumed and analyzed in this example.

The snubbing procedure discussed circulating at 2000 ft increments and circulating at "bottom." With the fish in the hole, "bottom" for the snubbing operation was 18,046 ft, which was 1400 ft from the bottom of the hole.

The theoretical implications of the concept of reverse circulating the influx through the drill pipe are interesting to consider. Certainly, the pressures in the annulus would be less if the influx was reversed. However, the pressure on the drill pipe must be considered. Consider Example 9.2:

Example 9.2

Given:

Assume 2000 ft of influx is to be reverse-circulated to the surface given the conditions in Example 9.1 and the capacity of the drill string, C_{ds}, is 0.00658 bbl/ft. The wellbore schematic is presented as Fig. 9.7.

Required:

The maximum pressure on the drill pipe.

Solution:

As determined in Example 9.1, when the first 2000 ft of influx was encountered, the top of the gas would have been at 15,560 ft. The volume of influx to be circulated to the surface would be 96 bbl.

Therefore, the length of the gas column inside the drill pipe would be

$$h = \frac{V}{C_{ds}}$$

$$h = \frac{96}{0.00658}$$

$$h = \mathbf{14,590\,ft}$$

The drill pipe pressure would be

$$P_s = P_b - \rho_m(D - h_b) - \rho_f h_b$$

$$P_s = 16,282 - (0.9568)(15,560 - 14,590) - 0.162(14,590)$$

$$P_s = \mathbf{12,990\,psi}$$

Example 9.2—cont'd

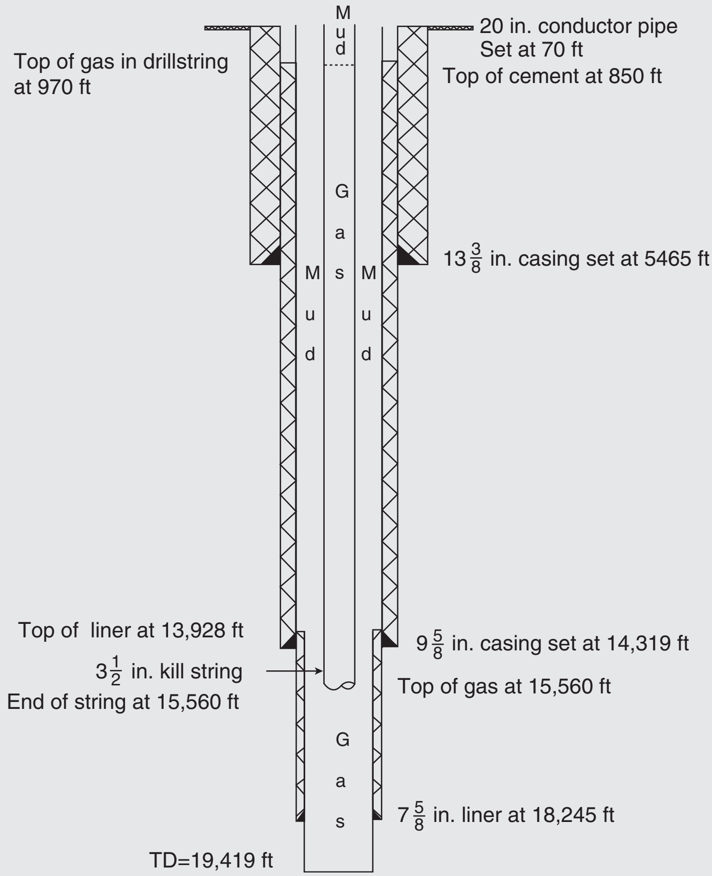

Fig. 9.7 Example 9.2.

As illustrated in Example 9.2, had the reverse circulation procedure been attempted, the drill pipe pressure could have been anticipated to reach a maximum of approximately 13,000 psi. It is unlikely that anyone would have been comfortable with pressures of this magnitude on the drill pipe and surface connections especially when that pressure is the result of gas containing 30% hydrogen sulfide.

The Significance of the Surface Pressures

The changes in surface pressure from the time of the initial influx on June 21 until July 15 are most interesting to analyze and study. During the first

18 days until July 9, the surface pressure remained relatively constant at 3700 psi. As discussed in Chapter 4, this constant surface pressure indicated that the influx did not migrate during this 18-day period.

After July 9, the surface pressure began to decline until July 15, the day of the surface failure and fire. The surface pressure had stabilized at approximately 2000 psi. As illustrated in Example 4.1, the decline in the surface pressure was the result of the migration of the influx. During the 6 days between July 9 and July 15, the influx had migrated to approximately 10,750 ft. The top of the influx on July 15 is substantiated by the analysis of the pumping operation prior to the fire, which is presented later in this text.

The Snubbing Operation to July 14

The snubbing operation proceeded routinely to July 14. On July 14, the end of the drill string was at approximately 4494 ft. The surface pressure was allowed to increase to 3800 psi prior to circulating the 18.4 ppg mud by not bleeding the quantity of mud displaced by the work string. Table 9.2 is a portion of the snubbing record for July 14. It is important to note that the 29 joints snubbed represent a displacement of 10.4 bbl. However, only 1.5 bbl were bled.

As discussed in Chapter 4, the displacement of each joint or stand should be bled as that joint is snubbed. Otherwise, it is more difficult to understand the hole condition, determine the proper surface pressure, or analyze influx migration. However, with the 3000 psi surface pressure at the beginning of the day, the top of the influx was well below the end of the work string.

The snubbing procedure was followed to establish the drill pipe pressure pursuant to the classical procedure. That is, the annulus pressure was held constant at 3800 psi, and the drill pipe pressure was established. The 18.4 ppg mud was then circulated to the surface with 276 bbl being pumped in and 265 bbl being recovered, the difference being the volume required to fill the drill pipe. After the pumping operation, the surface pressure stabilized at 2240 psi. No gas was circulated to the surface.

Since there was no gas in the drill pipe annulus and the influx did not migrate during the pumping operation, the displacement procedure proceeded without difficulty and was successful. For further discussion, refer to the section in Chapter 4 concerning circulating off bottom and the discussion previously presented in this section.

The Snubbing Operation, July 15

On the morning of July 15, the surface pressure was 2390 psi. The snubbing operation proceeded routinely. The snubbing procedure was altered to

Table 9.2 Snubbing record, E. N. Ross No. 2, Jul. 14, 1985

Pipe snubbed	Total depth of pipe	Displacement volume	Volume bled	Pressure
30.4	2161.37	0.36		3010
30.4	2191.77	0.36		3040
30.4	2222.17	0.36		3060
30.4	2252.57	0.36		3100
30.4	2282.97	0.36		3140
30.4	2313.37	0.36		3150
30.4	2343.77	0.36		3200
30.4	2374.17	0.36		3240
30.4	2404.57	0.36		3260
30.4	2434.97	0.36		3300
30.4	2465.37	0.36		3340
30.4	2495.77	0.36		3380
30.4	2526.17	0.36		3400
30.4	2556.57	0.36		3430
30.4	2586.97	0.36		3450
30.4	2617.37	0.36		3480
30.4	2647.77	0.36		3500
30.4	2678.17	(1.14)	1.5	3520
30.4	2708.57	0.36		3540
30.4	2738.97	0.36		3560
30.4	2769.37	0.36		3600
30.4	2799.77	0.36		3600
30.4	2830.17	0.36		3620
30.4	2860.57	0.36		3640
30.4	2890.97	0.36		3600
30.4	2921.37	0.36		3600
30.4	2951.77	0.36		3600
30.4	2982.17	0.36		3780
30.4	3012.57	0.36		3850

permit a bigger increment. Accordingly, the work string was snubbed to 8954 ft for a 4464 ft increment as opposed to the recommended 2000 ft interval. During the day, the surface pressure declined until the end of the day when it stabilized at 2000 psi. According to the analysis in Example 4.1, the top of the influx was at 10,250 ft. By rigorous analysis, the top of the influx was at 10,750 ft. The conditions at the E. N. Ross No. 2 on the evening of July 15 are illustrated in Fig. 9.8.

The Circulating Procedure, July 15

As outlined in the snubbing procedure, the casing pressure was held constant at 2000 psi, and the drill pipe pressure was established at 2900 psi at a rate of

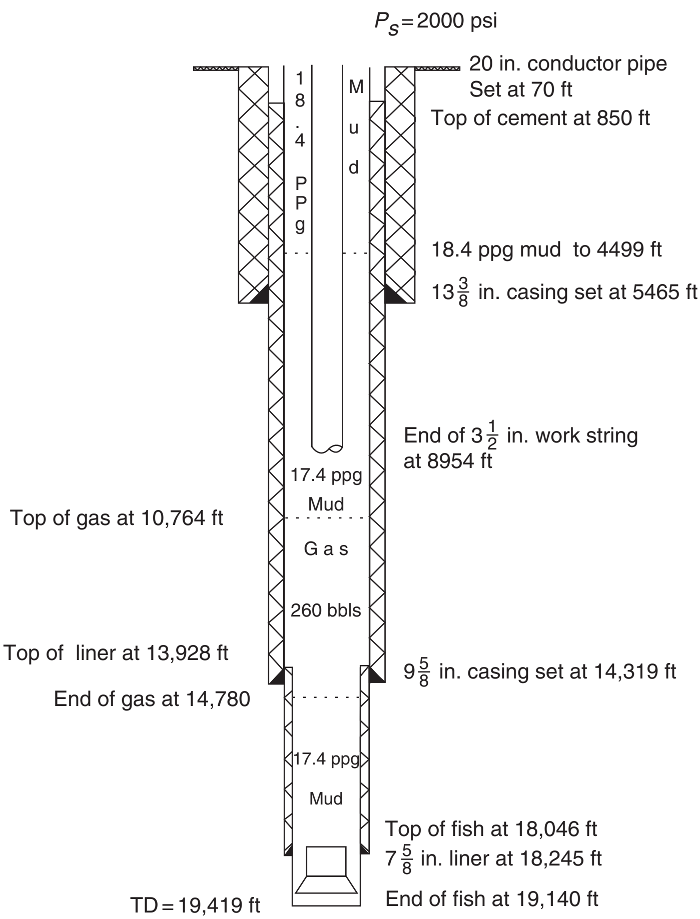

Fig. 9.8 Condition of E. N. Ross No. 2 on the evening of July 15.

3 bpm. Circulation commenced pursuant to Table 9.1 and Fig. 9.4. Given the wellbore schematic as illustrated in Fig. 9.8, the work string annular volume was 532 bbl. As previously noted, the pit level began to increase after pumping approximately 120 bbl into the drill string. It is important to recognize that, at that time, which was 1727 hours, the drill pipe pressure was constant at 2900 psi and the annulus pressure had declined to 1900 psi. Thereafter, the annulus pressure decreased to 1700 psi and then began to increase as the drill pipe pressure was held constant.

As illustrated in Table 9.1 during the 11 min period of 1826–1837 hours, 95 bbl of mud were recovered from the well for an average rate out of 8.64 bpm. The average pumping rate during the same time was 3.09 bpm for a net gain of 5.55 bpm. Therefore, interpolating Table 9.1, the annular volume of 532 bbl was recovered at approximately 1831 hours.

As previously stated, gas did not reach the surface until approximately 1854 hours or almost one-half hour after the recovery of the drill string annular volume and after a total of 725 bbl had been recovered. Therefore, it can be concluded that there was no gas present in the drill string annulus when the circulating operation commenced. It can also be concluded that the pit level gain, which commenced at 1727 hours after 120 bbl was pumped, was not the result of gas expansion in the drill string annulus.

It follows then that the gain and increase in annulus pressure was due to migration of the influx or an additional influx. Had the guidelines presented in Chapter 4 been followed, the operation would have been terminated when the pit level began to increase at 1727 hours. It could have been reasoned that the operation was not proceeding according to plan and procedure when the work string annulus volume had been recovered, no gas had been observed, and the annulus pressure was continuing to increase.

The top of the influx when circulation commenced can be substantiated by analyzing Table 9.1. Consider Example 9.3:

Example 9.3

Given:

Fig. 9.8

Table 9.2

Drill string annular capacity, $C_{dpca} = 0.0589$ bbl/ft

$9\frac{5}{8}$ in. casing capacity, $C_{ci} = 0.0707$ bbl/ft

Gas to surface with 390 bbl in and 725 bbl out

Required:

Estimate the top of the influx when circulation commenced.

Solution:

The volume of the drill string annulus is

$$V_{\text{dpca}} = D_{\text{dpca}}\left(C_{\text{dpca}}\right)$$
$$V_{\text{dpca}} = 8954(0.0589)$$
$$V_{\text{dpca}} = \mathbf{527\,bbls}$$

Volume pumped with 527 bbl out is approximately 320 bbl.

Volume in with gas to surface is 390 bbl.

Volume out with gas to surface is 725 bbl.

Volume pumped between annular volume out and gas to surface is

Continued

Example 9.3—cont'd

$$= 390 - 320$$
$$= \mathbf{70\,bbls}$$

Volume contributed by annulus is

$$= 725 - 527 - 70$$
$$= \mathbf{128\,bbls}$$

Top of influx when circulation commenced is

$$= \frac{128}{0.0707} + 8954$$
$$= \mathbf{10,764\,ft}$$

As illustrated in Example 9.3, 725 bbl of mud had been recovered when gas reached the surface (which is 198 bbl more than the drill string annular capacity). During the period in which the 198 bbl was being recovered, only 70 bbl was pumped into the well. Therefore, 128 bbl had to come from the hole below the end of the drill string. It follows that the top of the influx was at approximately 10,764 ft. A rigorous determination of the surface pressure and appropriate hydrostatics confirms this calculation to accuracy well within the limits of the data and accuracy of the pressure gauges being used.

The well was shut in and observed at 1942 hours. After 540 bbl of mud was pumped into the well, and 1054 bbl was recovered, the annulus pressure had increased from 2000 to 5000 psi. It was decided to proceed, keeping the annulus pressure constant and pumping at 6 bpm. As reflected in Table 9.1, from that time until the pump-in line ruptured, the drill pipe pressure increased from 2900 to 6700 psi.

As previously stated, there is no correct model for circulating off bottom with gas in the drill string annulus. Therefore, circulating with the drill pipe pressure constant at 3 bpm is theoretically as proper as circulating at 6 bpm with the annulus pressure constant. However, as illustrated in Fig. 9.4, the net gain decreased after increasing the pump rate to 6 bbl/min, indicating that the condition of the well was improving.

The pump and return lines for July 15 are schematically presented as Fig. 9.3. As illustrated, the hammer union failed on the rig floor. There were no check valves between the failure and the drill string, and the pump-out, back-pressure valve failed. With the annulus closed, the full force of the well was concentrated on the drill pipe, and the flow from the well continued to increase. Efforts to close the two ball valves on the top of the drill string were unsuccessful although both valves were represented to be applicable for the conditions experienced.

As noted in Chapter 1, ball valves can be problematic in well control problems. In this particular instance, the uppermost ball valve was of the type commonly known as a low-torque valve and is considered efficient for use in difficult circumstances (the lower valve was of the simple kelly-valve variety). During controlled tests after the incident, at various rates and pressures, the valves could not be consistently operated using the associated closing bars. Laboratory conditions are usually much less traumatic than the actual conditions experienced at the wellsite. A hydraulic valve would probably have operated. Also, a gate valve can always be closed on flow; however, it could erode if the flow rate is high or closing requires considerable time.

With all of the problems encountered, control of the well was being regained when the hammer union on the pump-in line washed out. Efforts to close the two valves were not successful under the conditions encountered even though they were represented to be applicable to those conditions. The well began to vent at the rig floor, and the hydrogen sulfide alarms began to sound. The rig was soon inaccessible due to the toxic nature of the gas, and there was little alternative but to ignite the gas.

ALTERNATIVES

It is interesting to consider the alternatives available to control the well. With the bottom 1400 ft of the hole lost to the fish, it is difficult to remove the influx from that portion of the hole. Therefore, there is no good, easy, foolproof procedure to control this well.

One alternative would have been to attempt to bullhead the influx back into the formation. However, with 1100 ft of open hole, it is unlikely that the influx would have been displaced into the Smackover. It is more likely that the fracture gradient at the shoe would have been exceeded and the influx above the shoe would have been displaced into the interval immediately below the shoe. The influx remaining in the bottom 1100 ft of open hole would have continued to be difficult.

The most intriguing aspect of the entire situation is that, for the first 18 days after the initial kick, the influx did not migrate and that, in the next 6 days, it only migrated less than 4000 ft to approximately 10,750 ft. One alternative well control procedure would have been to let the influx migrate to the surface. The procedures outlined in Chapter 4 could be used to design a migration schedule and anticipated annular pressure profile. The volumetric procedure is merely the driller's method with zero circulation rate. Consider Example 9.4:

Example 9.4

Given:

Examples 9.1, 9.2, and 9.3

Assume that the influx migrates to the surface.
The $3\frac{1}{2}$ in. drill string remains at 8954 ft.
The well contains only 17.4 ppg mud.
Assume the maximum surface pressure is 5000 psi.

Required:

1. The annulus pressure profile
2. The procedure for migration
3. The procedure for displacing the influx

Solution:

1. The procedure for determining the annulus pressure profile is the same as presented in Example 9.1. The surface pressure, under these conditions, with gas to the surface and a fish in the hole would be:

$$P_{0dm} = \mathbf{3510\,psi}$$

When first shut in, the top of the influx was at 13,546 ft and

$$P_a = \mathbf{3700\,psi}$$

The gas at 8954 ft, P_x, is given by Eq. (4.21):

$$P_{xdm} = \frac{B}{2} + \left[\frac{B^2}{4} + \frac{P_b \rho_m z_x T_x h_b A_b}{z_b T_b A_x}\right]^{\frac{1}{2}}$$

$$B = P_b - \rho_m (D - X) - P_f \frac{A_b}{A_x}$$

$$B = 16{,}907 - 0.9048(19{,}419 - 8954) \\ -0.162(5873)\left(\frac{0.0426}{0.0707}\right)$$

$$B = \mathbf{6892}$$

$$P_{8954dm} = \frac{6892}{2} + \left[\frac{6892^2}{4} + \frac{16{,}907(0.9048)(1.586)(636)(5873)(0.0426)}{1.988(772)(0.0707)}\right]^{\frac{1}{2}}$$

$$P_{8954dm} = \mathbf{10{,}314\,psi}$$

Example 9.4—cont'd

$$P_a = P_x - \rho_m X$$
$$P_a = 10,314 - 0.9048(8954)$$
$$P_a = \mathbf{2212\,psi}$$

The annulus pressure profile is presented in Fig. 9.9.

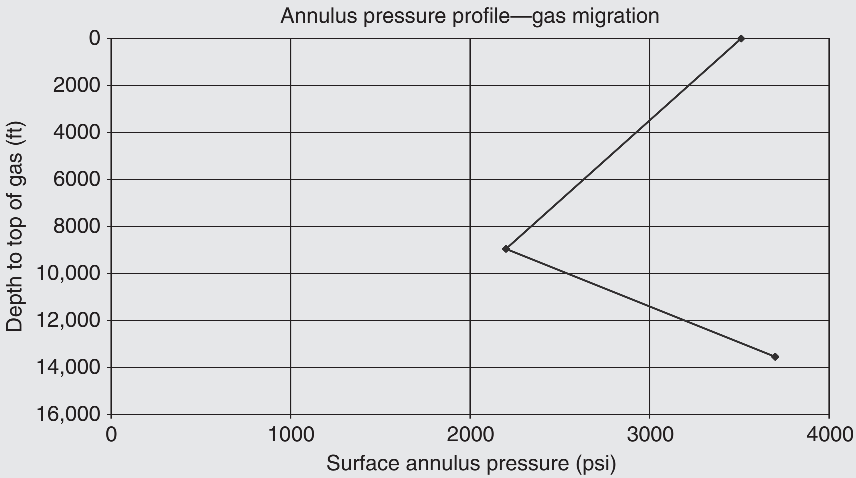

Fig. 9.9 Annulus pressure profile with the volumetric method.

2. The procedure for migration in this case is very simple. Assuming that the maximum casing pressure is 5000 psi, merely let the casing pressure increase to 5000 psi and bleed the mud necessary to keep the casing pressure constant at 5000 psi. The volume bled should not exceed the increased volume of the influx.

$$V_s = \frac{P_b z_s T_s}{P_s z_b T_b} V_b$$
$$V_s = \frac{16,907(0.775)(520)}{3510(1.988)(772)}(260)$$
$$V_s = \mathbf{329\,bbls}$$

Therefore, the additional gain is

$$\Delta V = 329 - 260$$
$$\Delta V = \mathbf{69\,bbls}$$

No more than 69 bbl of mud should be bled from the annulus as the influx migrates at 5000 psi.

Continued

Example 9.4—cont'd

3. Once the surface pressure stabilizes, the influx is at the surface and can be displaced using the driller's method, provided that the anticipated pressures and volumes are as predicted by the analysis. If not, the well must be shut in. Alternatively, a volumetric procedure could be used. The well could have been pressured to 5000 psi through the drill string while carefully measuring the mud pumped. After reaching 5000 psi, the annulus could have been bled to the stabilized surface pressure less the hydrostatic of the volume pumped.
For example, if $P_a = 3510$ psi and $V_s = 329$ bbl,

$$V_2 = \frac{P_1 V_1}{P_2}$$

$$V_2 = \frac{3510(329)}{5000}$$

$$V_2 = \mathbf{231\,bbls}$$

Or the volume of mud pumped to obtain 5000 psi would be

$$329 - 231 = 98\,\mathbf{bbls}$$

The effective hydrostatic of the additional 58 bbl is

$$\Delta Hyd = \frac{V_m}{C_{\text{dpca}}}\left(\rho_m - \rho_f\right)$$

$$\Delta Hyd = \frac{98}{0.0589}(0.9048 - 0.162)$$

$$\Delta Hyd = \mathbf{1236\,psi}$$

Therefore, the surface pressure could be bled from 5000 psi to 3510–1236 or

$$P_a = \mathbf{2274\,psi}$$

The procedure could be repeated until the influx is released. In this procedure, only *GAS* can be released.

As illustrated in Example 9.4, influx migration was a viable alternative. The maximum permissible surface pressure would not have been exceeded. The influx could have been displaced or released volumetrically.

Realizing that the influx had migrated to 10,750 ft would have offered an interesting alternative to consider. With the top of the influx at 10,750 ft, the bottom of the influx would have been at 14,780 ft. The work string could have been snubbed to the top of the fish and the influx circulated out using the driller's method. The anticipated pressures would be the same as determined in Example 9.1 with the exception that the influx would have begun above 10,000 ft as opposed to beginning from bottom. However, the risk is that, if there is additional influx below the end of the work string, the problems could be the same as occurred. Therefore, any displacement procedure must be carefully and completely analyzed. If there is any deviation from the analysis, the well must be shut in and evaluated.

Another alternative would have been to connect the well to the plant and flare lines and flow the well. Historically, the wells in the area produced only a few million cubic feet of gas per day. Therefore, the well might have been flowed for a short period until the flowing bottom-hole pressure was drawn down. After that, it could have been killed utilizing the dynamic momentum concepts described in Chapter 5. This would have been a good contingency for the effort to circulate from below the influx as previously described. As a matter of interest, when the well was finally capped after the fire, it was controlled as just described. A heavy-mud was pumped at a high rate with the well flowing. It died.

OBSERVATIONS AND CONCLUSIONS

There are very interesting and educational observations to be made. There were many instances in which the procedure was predicated on reaching "bottom." However, after the fish was left in the hole, it was no longer possible to reach total depth of 19,419 ft. With the top of the fish at 18,046 ft, "bottom" became 1373 ft less than total depth. Therefore, any theoretical procedure based on "bottom" was practically impossible. The concept of stripping to "bottom" and circulating out was theoretically impossible. With the drill string as deep as possible, 1373 ft of gas would remain below the end of the drill string.

In well control operations, circulating off bottom is rarely a good idea. In this case, the condition of the well deteriorated when circulation was attempted.

CHAPTER TEN

Contingency Planning

Monday, January 12, 1988

We came out of the hole with the core last night and noticed that the well was flowing. So, we picked up the bottom hole assembly and started back in the hole. We got to 1500 ft and the well was flowing too hard to continue. We shut in and had 500 psi at the surface. We picked up the kelly and circulated for one hour keeping the drillpipe pressure constant. Then, we shut in again and had 4200 psi at the surface. What do you want to do now?

For as long as oil and gas wells have been drilled, there have been kicks, blowouts, well fires, and other well control problems. It is certain that these problems will continue. In fact, a recent statistical study concluded that there are as many problems today as there were in the 1960s—which is rather startling considering the emphasis on regulation and training.

Well control in any and all forms can be accomplished by anyone. That is, anyone can put out a well fire and anyone can kill a well. The Al-Awda Project in Kuwait proved this point beyond a shadow of doubt. In Kuwait, fires were extinguished and wells killed by professionals, engineers, tool pushers, roughnecks, snubbing hands, schoolteachers, bartenders, mud engineers, farmers, Americans, Canadians, Iranians, Chinese, Romanians, Hungarians, Russians, and Kuwaitis. Interestingly, the average time required to control each well in Kuwait was essentially the same regardless of the composition or national origin of the team.

The consequences of a blowout can be staggering, as can the consequences of a bad decision during control attempts. There is the potential for loss of life, revenue, equipment, and vast quantities of natural resources. From the advent of well control as a profession in the early 20th century, until the early 1980s, only one life was lost—Myron Kinley's brother, Floyd, was killed on a rig floor while fighting an oil well blowout and fire. This is remarkable considering the conditions under which well control efforts are

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conducted. Since the early 1980s, several have been killed, including five (three professionals) at a blowout in Syria. Considering the present state of the industry, including the well control service providers, more are sure to be killed in the future.

Why has there been more loss of life? There are several reasons, in the opinion of this writer. One reason is that since the boom of the early 1980s and since the Gulf War, there are more well control "professionals." Another reason is that since the bust of the 1980s, the industry has lost a wealth of practical field experience. As the worldwide drilling manager for Amoco, George Boykin, in an address to the SPE/IADC Drilling Conference in the spring of 1998, complained that the industry was experiencing a crew change. With the contraction of the industry again in 2014, more of the experienced people will retire.

Well control operations are generally expensive to very expensive. Several blowouts in recent years have been reported to cost in excess of \$100 million. One was reported to cost in excess of \$250 million. Recovery and control operations at the Apache Key 1–11, which blew out in 1981 and was referred to by many as the biggest blowout in the history of the state of Texas, were reported to have cost in excess of \$50 million. It is estimated that the *Deepwater Horizon* blowout will cost in excess of \$50 billion after settling all the litigation.

The value of the forever-lost natural resources can exceed the recovery costs. At one international operation, more than two-thirds of one of the largest gas fields in the world has been lost to an underground blowout. As with many industries, environmental considerations can be a major expense. A burning gas well has very little environmental impact. However, with a spewing oil well, the cost of restoring the environment can exceed the recovery costs.

Costs and problems do not always end when the well is killed. The litigious nature of today's world results in extensive litigation, which often exceeds the life of the well and costs more than the control effort. For example, after the blowout at the Apache Key, the litigation included hundreds of litigants, cost hundreds of millions of dollars, and threatened the very existence of the company. The final legal issues were resolved in 1998, 17 years after the blowout.

The indirect costs and consequences to the energy industry can be equally staggering. The blowout in the Santa Barbara Channel significantly impacted the regulatory and environmental problems faced by the domestic industry. In Canada, a large sour gas blowout in 1985 forever changed the regulatory requirements, increased government intervention, and added to the cost of exploration. In the North Sea, the incident at the Piper Alpha platform and at the Saga blowout had similar consequences. The *Deepwater Horizon* blowout shut down drilling operations in the Gulf of Mexico and substantially changed the regulatory requirements. It even had a significant impact on land operations.

The operations group is faced with substantial responsibility with regard to well control and is challenged to minimize the impact of any well control event. As with any operation, management, planning, and execution are fundamental. In well control, a contingency plan is vital to minimizing the impact of the problem.

In the opinion of this writer, one of the most important functions of the contingency plan is to determine when additional expertise is required in any situation, under any circumstance. Specifically, at what point and under what circumstances does the driller involve the tool pusher and the tool pusher involve the drill site supervisor and the drill site supervisor involve the office. Once the office is involved, notifications are a function of the office structure. Also, at what point are the regulatory agencies and local authorities involved. The basic answer to this series of questions is that the next level of supervision must become active when the expertise of the first level is exceeded, a critical decision must be made, or when a crisis may be looming. Perhaps more important, when does the operator involve outside help in the form of a well control consultant? Again, the answer depends on the level of expertise of the operator. All team members should be encouraged to seek the next level of assistance. It is always better (and more cost effective) to have help and not need it than to need help and not have it.

The contingency plan must first and foremost emphasize the safety of the personnel at the well site. Any act or action that will expose well site personnel to the risk of personal harm must be discouraged. It is the responsibility of management to define the point at which the well and perimeter will be secured and the well site abandoned. It can never be forgotten that the principal components required for a fire are fuel, oxygen, and an ignition source. Anytime these three are present, all personnel in the immediate vicinity are in grave danger. The situation is even more serious if the wellbore fluids include toxic components such as hydrogen sulfide. Equipment can be replaced.

It is not possible to globalize a contingency plan to the extent that the only requirement is to fill in the blanks. A fat plan with endless flow charts and irrelevant information usually gathers dust on a shelf and is worse than no plan. It must be sufficiently site-specific to identify the personnel, equipment, and services required to address a potential well control scenario. For example, an operator in south Texas need not identify the location and capacity of various cargo planes, whereas an operator in the jungles of Africa needs that information.

For outside well control expertise, the operator faces a challenge. Historically, a well control "expert" was primarily a fire fighter. Since only about one surface blowout in a hundred catches fire, firefighting expertise is only one consideration. A well may blowout at the surface or it may blowout underground. The blowout may require surface or subsurface intervention or a relief well may be necessary. Choosing the appropriate form of expertise is a challenge.

The operator must evaluate the qualifications of the individuals to be utilized by the potential service providers. Bright coveralls and an arrogant attitude do not qualify someone to be a well control expert. Experience and qualifications may be difficult to determine. Well control operations are often cloaked in secrecy. The operator may be embarrassed by the loss or may fear litigation. As a result, follow-up investigations may not be sincere efforts. The service providers are not usually interested in divulging "trade secrets" such as their methodology, philosophy, or well control techniques for fear of losing a real or perceived competitive edge. Egos are huge. Claims on any job may be many. In some instances, a job has been brilliantly conducted. In other instances, the well control efforts have turned a serious well control problem into a major disaster. Unfortunately, both may be proclaimed as a triumph. Ignorance and arrogance are a dangerous combination.

The best contingency plan will include a well control consultant with nothing to sell but his time. Some operators identify and depend on individual experts for various functions regardless of their company affiliation. It has become popular for some large service providers to offer total services. However, that approach is not always economical. The service provider may be more interested in providing unnecessary pumping services, if that is the primary service line, at the expense of the project.

CHAPTER ELEVEN

The Al-Awda Project: The Oil Fires of Kuwait

No text on advanced pressure control would be complete without a brief history and overview of this historical project. I am proud to have served the Kuwait Oil Company and the Kuwaiti people in their effort. I consider my involvement one of the greatest honors of my career.

No picture can capture and no language can verbalize the majesty of the project. It was indeed beyond description by those present—and beyond complete appreciation by those not present. A typical scene is shown in Fig. 11.1 which was photographed during the day. The smoke turned day to night.

With these extensive oil fires, the rape of Kuwait was complete. The retreating Iraqi troops had savagely destroyed everything in the oil fields. There was nothing left to work with. There were no hand tools, no pump trucks, no cars, no pickups, no housing—nothing. Everything necessary to accomplish the goal of extinguishing the fires and capping the wells had to be imported.

The world owes the valiant Kuwaitis a great debt. To extinguish almost 700 oil well fires in eight months is an incredible accomplishment, especially in light of the fact that Kuwait is a very small country of only 1.5 million people that had been completely and ruthlessly pillaged. No one worked harder or longer days than the Kuwaitis. Many did not see their families for months and worked day after day from early morning until long after dark for days, weeks, and months in their tireless effort to save their country.

OVERVIEW OF THE PROJECT

As understood by the author, the basic organization chart, effective after Aug. 1, 1991, as pertained to firefighting and well control, is presented as Fig. 11.2. The oil fields of Kuwait are shown in Fig. 11.3.

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Fig. 11.1 Greater Burgan field.

Greater Burgan field is the largest oil field in Kuwait. Larry Flak was the coordinator for the fields outside Burgan, which were Minigish and Raudatain. Texaco was responsible for the wells in the neutral zone and the British Consortium was responsible for Sabriyah. The Kuwaiti Wild Well Killers (KWWK) were responsible for the wells in Umm Gudair. Larry Jones, a former Santa Fe employee, was charged with contracts and logistics. Abdoulla Baroun, an employee of Kuwait Oil Company, liaisoned between Kuwait Oil Company and the multinational teams.

By August 1, 8–12 teams from four companies had controlled 257 wells with most of the wells being in the Ahmadi and Magwa fields, which are nearest to Kuwait City. After Magwa and Ahmadi, the primary emphasis was on the Burgan field. However, as additional teams arrived, the original teams were moved to the fields outside Burgan. By the end of the project in early November, there were 27 firefighting teams deployed in Kuwait as shown in the organization structure (Fig. 11.2).

Thousands were involved in these critical operations and all deserve mention. Almost all of the support was provided by Bechtel under the very capable management of Tom Heischman. Texaco furnished support in the Neutral Zone, and the British Consortium furnished most of the support in Sabriyah. A substantial contribution was made by the management and employees of Santa Fe Drilling Company, many of whom were

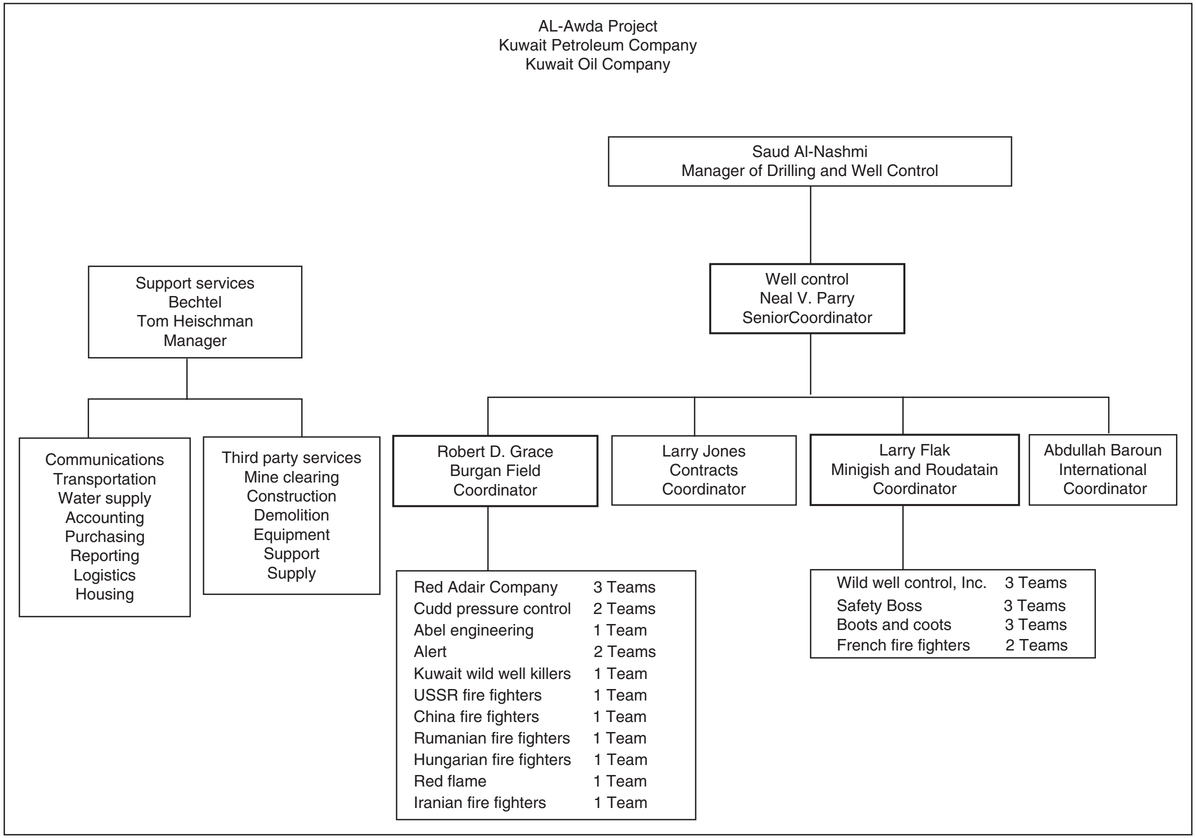

Fig. 11.2 Al-Awda Project organization chart.

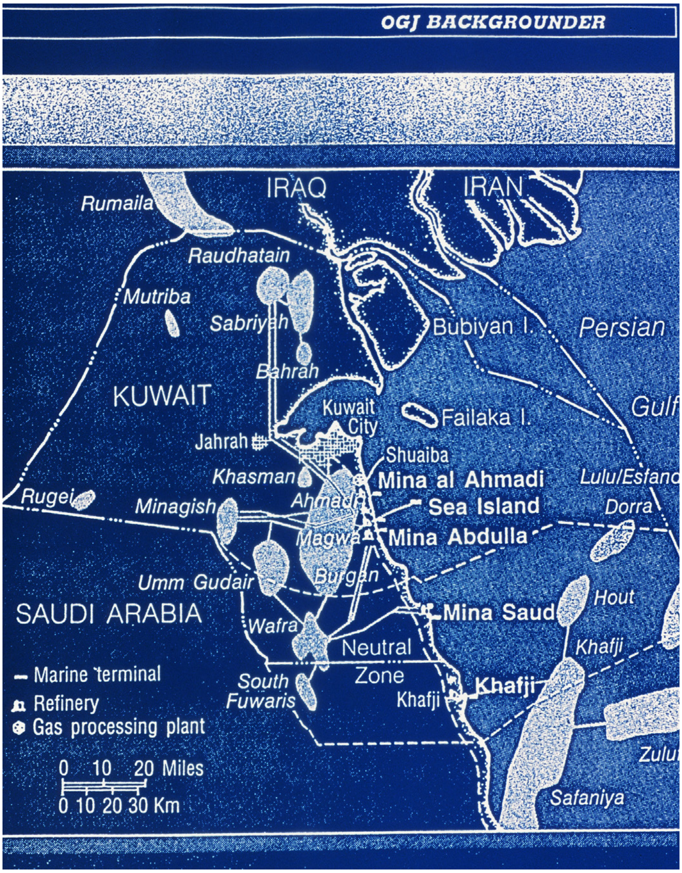

Fig. 11.3 Oilfields of Kuwait.

among the first to return to Kuwait after the war. One of the many contributions made by Santa Fe Drilling Company was the supply of heavy equipment operators who worked side by side with fire fighters to clear the debris and extinguish the fires.

An early report of the status of the fields and wells in Kuwait is presented as Table 11.1. In most of the fields, it was easy to determine the status of each individual well. Such was not the case in Burgan field. In Burgan, the well density was very high. The smoke reduced visibility to a few feet, and access to some parts of the field was impossible until the very end of the project. Even in the last few weeks, there was disagreement concerning the status of individual wells. However, the totals were very

Table 11.1 The Al-Awda Project: oil wells survey data by field

Field	Total number of wells					Remarks
	Drilled	On fire	Oil spray	Damaged	Intact	
Magwa	148	99	5	21	15	Figure excludes shallow wells
Ahmadi	89	60	3	17	6	
Burgan	423	291	24	27	67	
Raudatain	84	62	3	5	3	
Sabriyah	71	39	4	9	2	
Ratqa	114	0	0	0	8	
Bahra	9	3	2	[a]	[a]	
Minagish	39	27	0	7	1	
Umm Gudair	44	26	2	10	2	
Dharif	4	0	0	0	3	
Abduliyah	5	0	0	0	4	
Khashman	7	0	0	1	1	
Total	1037	607	43	97	112	

[a]Denotes uncertain about figure.

Fig. 11.4 Gray compact head.

accurate considering the circumstances. A typical day in Burgan field is shown in Fig. 11.1.

The majority of the wells in Kuwait are older and shallow (less than 5000 ft) with surface pressures less than 1000 psi. Typically, they were completed with $3\frac{1}{2}$ in. tubing inside a 7 in. casing and produced through both the casing and the tubing. The older wells had the old-style Gray Compact Head that houses all of the casing hangers in one body in progressively larger mandrels. A Gray Compact Head is pictured in Fig. 11.4. The newer and deeper wells had higher pressures and more conventional wellheads.

The Iraqi troops packed plastic explosives around the bottom master valve on the tree and on the wing valves on the "B" section. Sand bags were then packed on top of the explosives to force the explosion into the tree. The force of the explosion was tremendous and the damage indescribable.

In fortunate instances, such as pictured in Fig. 11.5, the tree was blown off at the bottom master valve and there was no other damage. In that case, the fire burned straight up and the oil was almost totally consumed. However, the vast majority of cases were not so simple. In most instances the destruction of the tree was not complete, and, as a result, oil flowed out of multiple cracks and breaks. As a consequence, the combustion process was incomplete. The unburned oil was collected around the wellhead in

Fig. 11.5 Tree blown off with complete combustion.

Fig. 11.6 Oil lakes around damaged wells with incomplete combustion.

lakes that were often several feet deep (Fig. 11.6). The ground throughout the Burgan field was covered with several inches of oil. Ground fires covering hundreds of acres were everywhere (Fig. 11.7). In addition, some of the escaping unburned oil was cooked at the wellhead and formed giant mounds of coke (Fig. 11.8).

Fig. 11.7 Example of ground fires in Greater Burgan field.

Fig. 11.8 Mound of coke had to be removed to get to the well.

While the coke mounds were an immediate problem for the firefighters, perhaps they were a benefit to Kuwait and the world. The coke accumulations served to choke the flow from the affected wells. In all probability, the reduction in flow rate more than offset the additional time required to cap the wells.

THE PROBLEMS

The Wind

The wind in Kuwait was a severe problem. Normally, it was strong from the north to northwest. This strong, consistent wind was an asset to the firefighting operation. However, during the summer months, the hot wind was extremely unpleasant. In addition, the sand carried by the wind severely irritated the eyes. The only good protection for the eyes was to wear ordinary ski goggles. It was expected that the summer "schmals" or wind storms would significantly delay the operations. But such was not the case. The oil spilled onto the desert served to hold the sand and minimize the intensity of the wind storms. As a result, the operation suffered few delays due to sandstorms.

The wind was most problematic on those occasions when there was no wind. During these periods, it was not uncommon for the wind direction to change 180 degrees within fifteen minutes. In addition, the wind direction would continue to change. Any equipment near the well might be caught and destroyed by the wind change. In any event, all of the equipment would be covered with oil, and the operation would be delayed until it could be cleaned sufficiently to continue. These conditions could persist for several days before the wind once again shifted to the traditional northerly direction.

The humidity in the desert was normally very low. However, when the wind shifted and brought the moist Gulf air inland, the humidity would increase to nearly 100%. When that happened, the road would become very slick and dangerous. On several occasions, there were serious accidents. In one case, a man was paralyzed as a result of an automobile accident caused by the slick road.

Logistics

The first problem was to get to the location. Access was provided to the firefighters by the explosive ordinance division (EOD), who cleared the area of explosives remaining from the war, and by Bechtel, who was responsible for furnishing the location and supplying water for firefighting. Everyone involved in this aspect (and there were many) did an incredible job. Close cooperation was vital in order to maintain efficiency in strategy planning. The goal was to keep all teams working to the very end of the project.

During the height of the activity in September and October, it was not unusual to haul 1500 dump truck loads of road and location building material each day and several hundred loads during the night.

It was not possible to survey the locations in the oil lakes for munitions. Therefore, access was safely gained by backing the truck to the end of the road and dumping a few cubic yards of material into the lake, hoping that the dirt would cover any ordinance. A dozer would then spread the material and the process would be repeated until the location was reached.

Water

The water system was constructed from the old oil gathering lines (illustrated in Fig. 11.9). Most of the lines had been in the ground for many years and all had been subjected to munitions. Therefore, it was not unusual for a water line laid across the desert to look like a sprinkler system. In spite of everything, 25 million gallons of water were moved each day. Lagoons were dug and lined at each location, when the gathering system was capable of supporting the lagoon with water. The capacity of the lagoons was approximately 25,000 bbl.

Sufficient water was always a problem. Water was continually pumped into the lagoon during the firefighting phase of the operation. Generally, the lagoon would fill overnight. During the last days of the project, two lagoons were constructed in the Burgan field at locations predicted to be difficult. Because the team concentration increased near the end, the demand on the isolated working area was very great. In spite of all obstacles, in these last days, water was not a problem for the first time during the project. In areas where water could not be transported by pipeline, frac tanks were used, and water was trucked from nearby loading points.

Ground Fires

Once the location was reached, the firefighters took over and spread the material to the well. In the process, ground fires had to be controlled and were a major problem. The ground fires often covered tens of acres. In many instances, we were not able to identify the well. The ground fires were fed by the unburned oil flowing from the coke mounds or from the wells themselves after the fire had been extinguished. Most of the time, the wild well fighters worked on a live well with a ground fire burning less than 100 yards downwind.

The worst ground fires were in the heart of Burgan. In anticipation of the problems, together with Safety Boss personnel, a unit was specially designed to fight the ground fires. It consisted of a 250 bbl tank mounted on Athey Wagon tracks. A fire monitor was mounted on top of the tank, and a fire

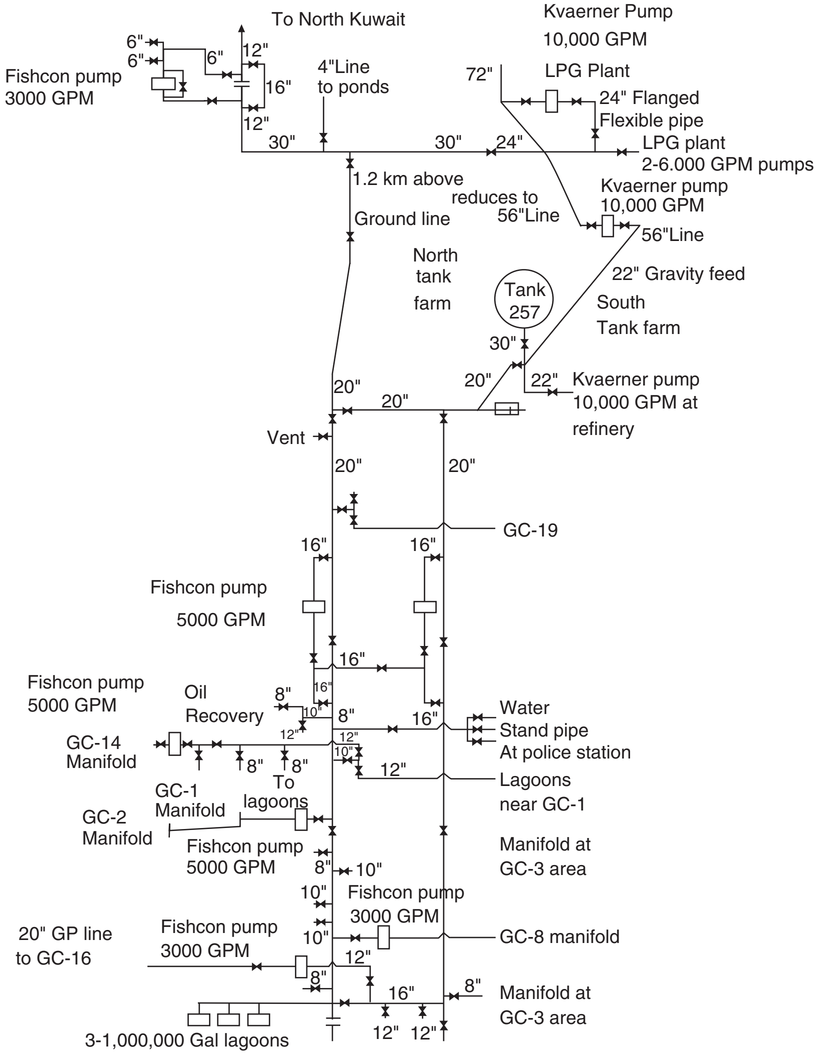

Fig. 11.9 The water supply system.

pump was mounted on the rear of the tank. It was pulled by a D-9 Cat and followed by a D-8 for safety. It had a built-in inductor tube to disperse various foaming agents commonly used in firefighting. The crew routinely worked between the blowing well and the ground fire and would be covered with oil every day. "Foamy One," pictured in Fig. 11.10, and her crew made a tremendous difference and contribution to the effort.

Fig. 11.10 Fighting ground fires with a foam system.

The Rumanian and Russian fire fighters were particularly good at fighting and controlling ground fires. They both brought fire trucks capable of spreading powder and chemicals to smother the ground fires. Their efforts contributed significantly to the success of the project. In all cases, the hot spots had to be covered with dirt to prevent reignition. Some of the hot spots continued to burn for months. They often were not visible during the day. However, at night, the desert fire was clearly visible. One of the last projects was to cover these persistent devils.

Oil Lakes

In addition to the ground fires, unburned oil had gathered into huge lakes. Often the lake surrounded the well. In one instance, fire came out one side of the coke pile and a river of oil flowed down the other side of the coke pile. The lakes could be several feet deep. Often the lakes caught fire and burned with unimaginable intensity, producing tremendous volumes of smoke.

Working in the lakes was very dangerous because the access roads could become bounded by fire, trapping the workers. After the oil weathered for several days, it was less likely to burn. Therefore, most lake fires could be extinguished by eliminating the source of fresh oil. In the latter days, the problem was solved by surrounding the burning well in the lake with a road approximately 50 ft in width. The road was then crossed by fire jumps in strategic locations that isolated the fire from the fresh oil in the lake.

The approach was successful. Had some of the bigger lakes caught fire, they would have burned for weeks (see Fig. 11.6).

The Coke Piles

Once the well was reached, the wellhead had to be accessed. Typically, each firefighting team had fire pumps, Athey Wagons, monitor sheds, cranes, and two backhoes—a long reach and a Caterpillar 235. The first step was to spray water on the fire from the monitor sheds in order to get close enough to work. The average fire pump was capable of pumping approximately 100 bbl of water per minute, and two were usually rigged up on each well.

Although the lagoons contained approximately 25,000 bbl of water, they could be depleted very rapidly at 200 bbl per minute. Using the water cover, the monitor sheds could be moved to within 50 ft of the wellhead. The long reach backhoe could then be used to dig away the coke pile and expose the well head. This operation is illustrated in Fig. 11.11.

As previously mentioned, some of the unburned oil cooked around the wellhead to form a giant coke pile. The coke pile formed like a pancake 100 ft in diameter. At the wellhead itself, the coke pile might be as large as 30–40 ft high and 50–70 ft in diameter. It had the appearance of butter on top of a pancake.

Fig. 11.11 Removing the coke pile and exposing the wellhead.

In some instances, the coke piles were very hard and difficult to dig. In other instances, the coke was porous and easily removed. It was not unusual for fire to burn out one side of the coke pile while oil flowed out another side.

In the northern fields, berms had been constructed around the wellheads. These quickly filled up with coke. Digging the coke resulted in a pot of boiling, burning oil.

CONTROL PROCEDURES

After exposing the wellhead, the damage was assessed to determine the kill procedure. Eighty-one percent of the wells in Kuwait were controlled in one of three procedures. The exact proportions are presented in Table 11.2.

The Stinger

If the well flowed straight up through something reasonably round in shape, it would be controlled using a stinger. As shown in Table 11.2, a total of 225 wells were controlled using this technique. A stinger was simply a tapered sub that was forced into the opening while the well flowed and sometimes while it was still on fire. The stinger was attached to the end of a crane or Athey Wagon. The kill mud was then pumped through the stinger and into the well. If the opening was irregular, materials of irregular shapes and sizes were pumped to seal around the stinger.

Due to the low-flowing surface pressures of most of the wells, the stinger operations were successful. However, stingers were not normally successful on openings larger than 7 in. or on higher pressured wells. A typical stinger operation is schematically illustrated in Fig. 11.12.

The Capping Spool

Another popular alternative was to strip the wellhead to the first usable flange. Using a crane or an Athey Wagon, a spool with a large ball valve

Table 11.2 Summary of kill techniques

Stinger	225
Kill spool	239
Capping stack	94
Packer	11
Other	121
Total	690

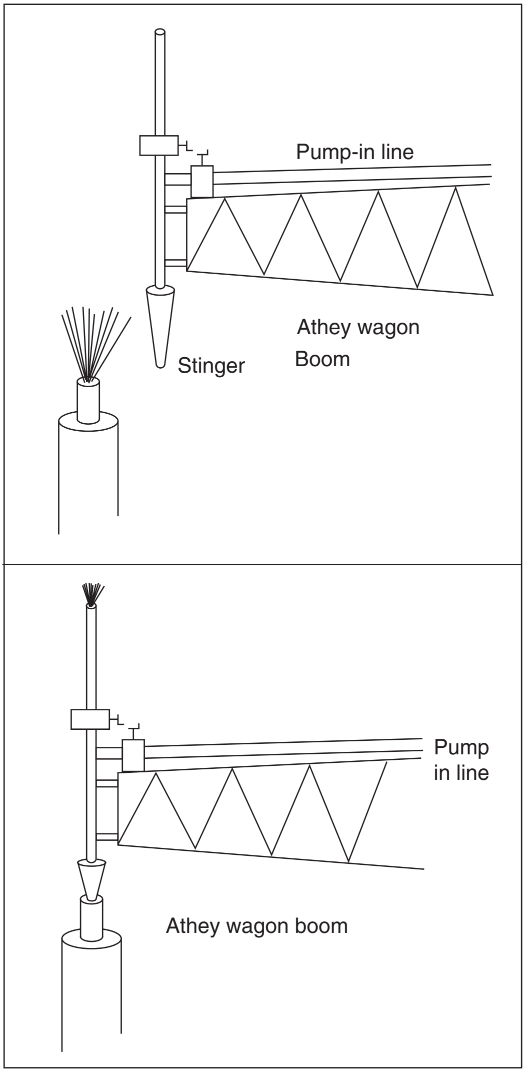

Fig. 11.12 Typical stinger kill operation.

on top was then snubbed onto the usable flange remaining on the tree. The valve was then closed and the well killed through a side outlet on the spool below the ball valve. This procedure was referred to as a capping spool operation and is illustrated in Figs. 11.13 and 11.14. As shown in Table 11.2, 239 wells were controlled using this technique. This operation was performed after the fire had been extinguished.

Fig. 11.13 Capping spool kill method.

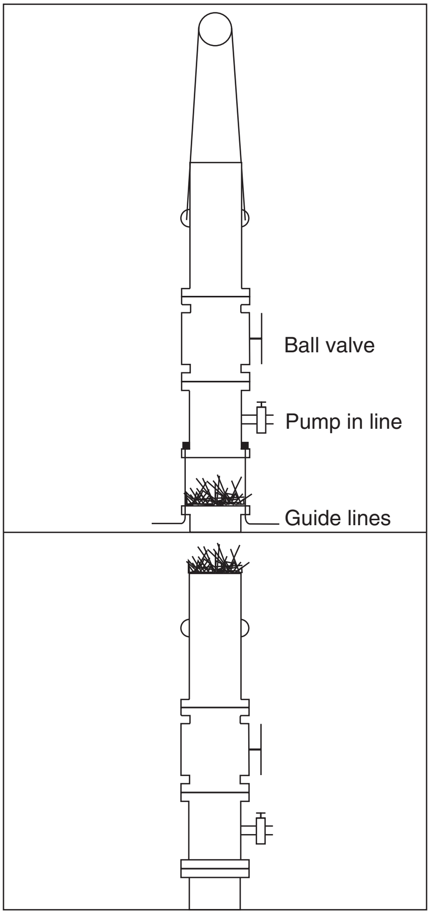

Fig. 11.14 Schematic of a capping spool operation.

The Capping Stack

Failing the aforementioned alternatives, the wellhead was completely stripped from the casing. This operation was accomplished with and without extinguishing the fire. In some instances, the wellhead was pulled off with the Athey Wagon. In other instances, it was blown off with explosives. In the early days of the effort, it was cut off using swabbing units and wire lines. In the final four months, the procedure often involved the use of high-pressure water jet cutters. (Cutting will be discussed later.) After the wellhead was removed, the casing strings were stripped off using mechanical cutters, commonly known as port-a-lathes, leaving approximately 4 ft of the string to receive the capping stack.

The wells were normally capped with a capping stack on the 7 in. production casing. Fortunately, all of the casing strings in the wells in Kuwait were cemented to the surface. Therefore, when the wellheads were severed from the casing, they did not drop or self-destruct as would commonly occur in most wells. The capping stack consisted of three sets of blowout preventers (Fig. 11.15). The first set were slip rams designed to resist the upward force caused by the shut-in well. The second set were pipe rams turned upside down in order to seal on the exposed 7 in. casing. A spool with side outlets separated the slip rams from the uppermost blind rams.

After the wellhead was removed, the fire was extinguished. The casing was stripped, leaving approximately 4 ft of 7 in. casing exposed. Normally, a crane would be used to place the capping stack on the exposed casing. Once the capping stack was in place, the pipe rams were closed, followed by the slip rams. The well would now flow through the capping stack.

When the pump trucks were connected and all was ready, the blind rams were closed. The pump trucks then pumped into the well. This operation has been performed elsewhere on burning wells, but was performed in Kuwait only after the fires were extinguished. The capping stack operation was performed on 94 wells in Kuwait. BG-376 was the last blowout in the Burgan field and was controlled on Nov. 2, 1991. Fig. 11.16 depicts the capping stack operation at BG-376.

EXTINGUISHING THE FIRES

Water

Extinguishing the fires in Kuwait was the easiest part of the entire operation. Three basic procedures were employed, though no official records

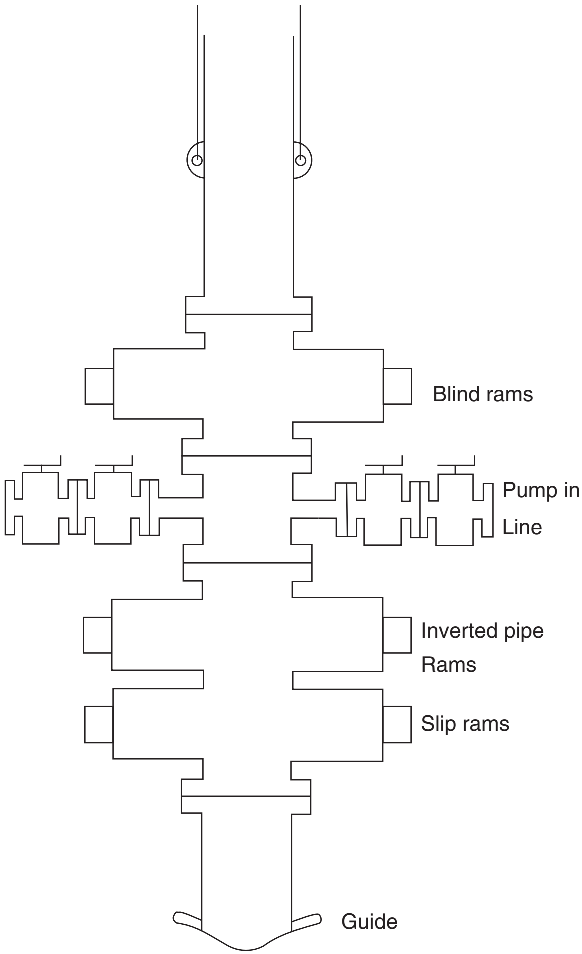

Fig. 11.15 Capping stack.

were kept. However, the vast majority of the fires were extinguished using the water monitors. The oil contained asphalt and was of low gravity; therefore, it was less volatile than most crudes. Usually three to five monitors were moved close to the fire, and the flow was intensified at the base of the fire. As the area cooled, the fire began to be interrupted. One monitor sprayed up along the plume to further cool the fire. Very large well fires were extinguished in just minutes. Fig. 11.17 illustrates the use of the fire monitors to extinguish a fire.

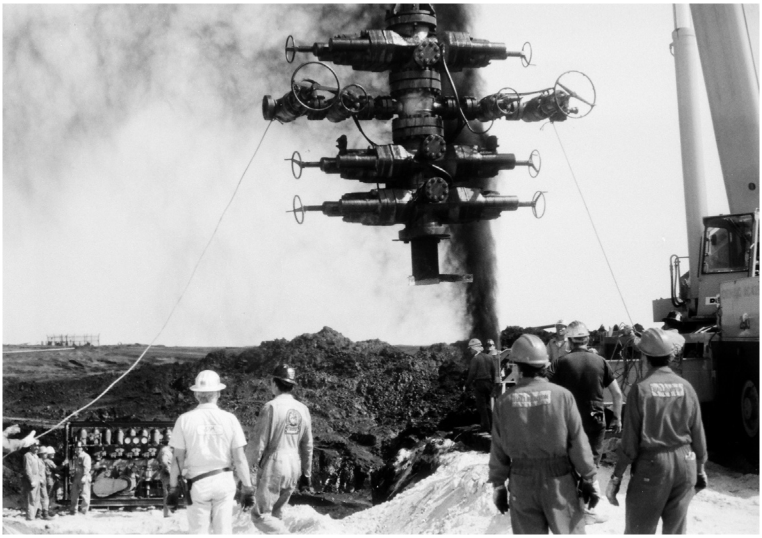

Fig. 11.16 Capping stack being installed on BG-376.

Fig. 11.17 Extinguishing a fire with water.

Some of the teams used fire suppression materials and chemicals to effectively extinguish the fires and minimize their water requirements. A much broader use of these materials would have more effectively conserved the precious water supplies.

Nitrogen

Prior to the availability of the required volumes of water, many fires were extinguished using nitrogen. A 40 foot chimney attached to the end of an Athey Wagon was placed over the fire, causing the flow to be directed up through the chimney. The fire burned only out of the top of the chimney. Nitrogen was then injected into the chimney through an inlet at the base. A typical chimney is shown in Fig. 11.17.

Explosives

Of course, some of the fires were extinguished using explosives. Explosives effectively rob the fire of the oxygen necessary to support combustion. The fire monitors were used to cool the fire and the area around the fire in order to prevent reignition. Charge size ranged from 5 lb of C_4 to 400 lb of dynamite. The charges were packed into a drum attached to the end of an Athey Wagon boom. Some included fire suppressing materials along with the explosives. The drum was wrapped with insulating material to insure that the explosives did not merely burn up in the fire. The explosives were then positioned at the base of the plume and detonated. Fig. 11.18 illustrates a charge being positioned for detonation.

Fig. 11.18 Explosive charge being positioned for detonation in order to extinguish the fire.

Novel Techniques

One technique captured considerable publicity and interest. The Eastern Bloc countries—Russia, Hungary, and Rumania—used jet engines to extinguish the fire. The Hungarian fire fighters were the most interesting. Their "Big Wind" consisted of two MIG engines mounted on a 1950s vintage Russian tank. Water and fire suppressants were injected through nozzles and into the vortex by remote control. The tank was positioned approximately 75 ft from the fire, and then, the water lines were connected. The engines were turned on at low speed and the water started to protect the machine as it approached the fire. The tank was then backed toward the fire. Once positioned, the speed of the engines was increased and the fire was literally blown out as one would blow out a match. The Hungarian "Big Wind" is illustrated in Fig. 11.19.

CUTTING

In the early days of the firefighting operation, a steel line between two swab units was used to saw casing strings and wellheads. This technique proved to be too slow. By early August, pneumatic jet cutting had completely replaced the swab lines. Water jet cutting is not new technology even to the well control business; however, techniques were improved in Kuwait.

Fig. 11.19 Blowing out a fire with jet engines.

Two systems were primarily used in Kuwait. The most widely used was the 36,000 psi high-pressure jet system using garnet sand. A small jet was used with water at 3–4 gal per minute. Most often, the cutter ran on a track around the object to be cut. In other instances, a handheld gun was used, which proved to be very effective and useful. More than 400 wells employed this technique.

One limitation was that the fire had to be extinguished prior to the cut and the cellar prepared for men to work safely at the wellhead. Another aspect had to be evaluated before widespread use was recommended. In the dark of the smoky skies or late in the evening, the garnet sand caused sparks as it impacted the object being cut. It was not known if under certain circumstances, these sparks would have been sufficient to ignite the flow. However, reignition was always of concern.

Another water jet system used a 3/16 jet on a trac or yoke attached to the end of an Athey Wagon boom. The trac permitted cutting from one side with one jet while the yoke involved two jets and cut the object from both sides. The system operated at pressures ranging from 7500 psi to 12,500 psi. Gelled water with sand concentrations between 1 and 2 ppg was used to cut. The system was effective and did not require the men to be near the wellhead. In addition, the system could be used on burning wells, provided the object to be cut could be seen through the fire. This technology was used on 48 wells.

Conventional cutting torches were used by some. A chimney was used to elevate the fire and the workers would cut around the wellhead. Magnesium rods were also used because they offered the advantage of being in 10 foot lengths that could be telescoped together.

STATISTICS

The best authorities predicted that the operation would require 5 years. It required 229 days. The project's progress is illustrated in Figs. 11.20 and 11.21. Originally, there were only four companies involved in the firefighting effort. At the beginning of August, additional teams were added, forming a total of 27 teams from all over the world. The companies that participated and the number of wells controlled by each company are shown in Table 11.3. The number of wells controlled by each company listed in Table 11.3 is not significant because some companies had more crews and were in Kuwait for a longer period of time. What is significant is that the most difficult wells were controlled after August 1. As shown in Fig. 11.21, the number of team days per well was essentially constant at

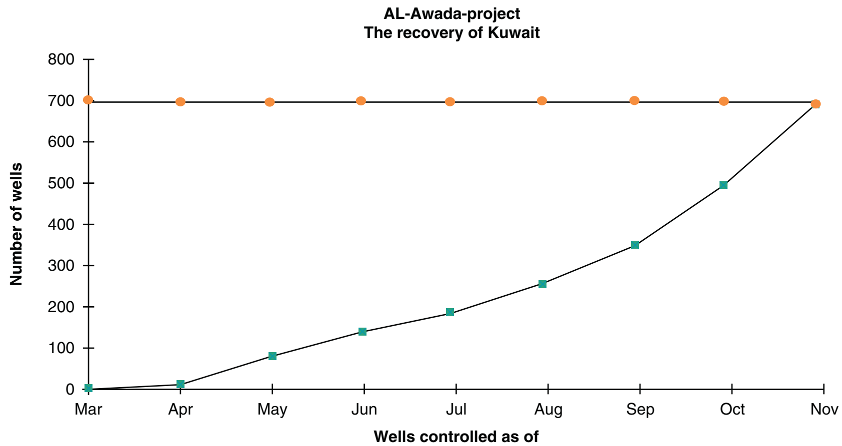

Fig. 11.20 Number of wells controlled by time.

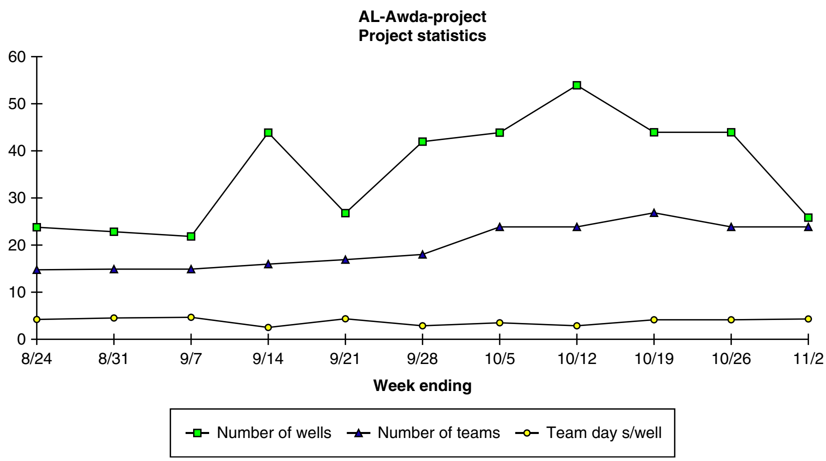

Fig. 11.21 Statistics for the Al-Awada project by week.

approximately four team days per well. That is not to say that some wells were not more difficult and that some teams were not better.

As also illustrated in Fig. 11.21, the high was reached in the week ending October 12, when a record 54 wells were controlled in seven days. For the month of October, 195 wells were controlled for an average of 6.3 wells per day. The record number of wells controlled in a single day was 13.

Table 11.3 The Al-Awda Project: oil wells secured and capped

Contractor's name	Total
Red Adair (American)	111
Boots and Coots (American)	126
Wild Well Control (American)	120
Safety Boss (Canadian)	176
Cudd Pressure Control (American)	23
NIOC (Iran)	20
China Petroleum	10
Kuwait Oil Company (KOC)	41
Alert Disaster (Canadian)	11
Hungarian	9
Abel Engineering (American)-KOC	8
WAFRA	31
Rumanian (Romania)	6
Red Flame (Canadian)-KOC	2
WAFRA	5
Horwell (French)	9
Russian	4
British	6
Production maintenance	9
Total	727

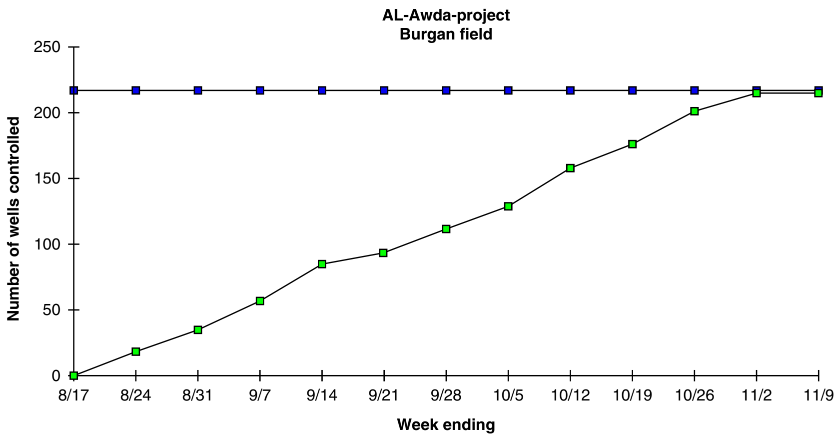

Fig. 11.22 Number of wells controlled by time (Burgan field).

Figs. 11.22 and 11.23 illustrate the statistics for the Burgan field. A high of 15 teams were working in Burgan in late August. Beginning in early September, the teams were moved to the fields in the north and west. They were replaced with teams from around the world. Figs. 11.21 and

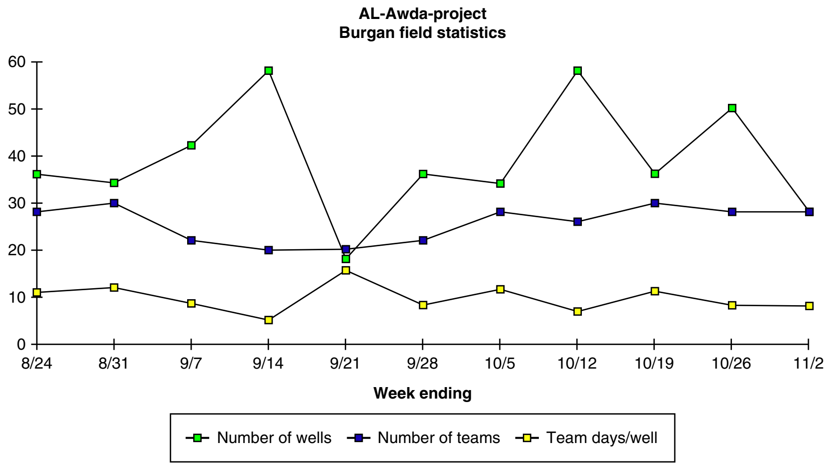

Fig. 11.23 Statistics for Burgan field by week.

11.23 show that the number of team days per well actually decreased between August and November from an average of five team days per well to an average of four team days per well.

As illustrated in Fig. 11.23, the progress in Burgan was consistent. As can be noted in Fig. 11.23, the best progress was recorded during the week ending September 14 when 29 wells were controlled by 10 teams at just over 2 team days per well. The tougher wells in Burgan were controlled in the latter days of the project.

SAFETY

There were 11 fatalities associated with the Kuwait fires as of the official end of the project on Nov. 6, 1991.

Every firefighting team was assigned an ambulance and a medic. These men were lifesavers in this harsh environment. They were always present with water and other drinks for the parched workers. In addition, they were able to treat minor illnesses and provide support for medical helicopters. It was routine to have an injured man in the hospital within 10–15 min of an injury being reported.

The British Royal Ordnance did a marvelous job of clearing the well sites of mines and other munitions. A path and area for the fire fighters were routinely checked. Any explosives too near the flames would have been consumed by the fire. Therefore, the firefighters were safe from these problems. However, by the end of the project, EOD had lost two men to land mine clearance. One was killed while clearing a beach. The other was killed while working a mine field in the Umm Gudair field when the mine inexplicably detonated.

The worst accident occurred very early in the project. Smoke from a burning well along the main road between Ahmadi and Burgan routinely drifted across the road. Just as routinely, the crews became accustomed to the situation and regularly drove through the smoke. On this particular day, there was fire in the smoke and in the ditches beside the road. Three service company men in one vehicle and two journalists in another vehicle apparently became disoriented in the smoke and drove into the fire. All five perished. In other instances, one man was killed in a pipeline accident and another in a road accident involving heavy equipment.

Of the firefighters, the Chinese team had one man severely burned, but his life was never in danger. In addition, at the end of the project, two members of the Rumanian team were badly burned late one evening when the wind died and gas fumes gathered. The fumes were ignited by a hot spot from a previously extinguished ground fire. Both were airlifted to Europe but later died.

CONCLUSION

Pursuant to documents filed with the United Nations Security Council in 1996, the total damage inflicted by Iraq, excluding the value of the lost reserves, was $951,630,871, of which the Al-Awda Project cost was $708,112,779, or over $3 million per day. It was estimated that in the beginning five to seven million barrels of oil per day were being consumed by the fires. More than 10,000 nonmilitary personnel from 40 countries and all continents except Antarctica supported the firefighters.

It is estimated that the wells emitted approximately 5000 tons of smoke daily in a plume 800 miles long. More than 3.5 million meals were served during the Al-Awda Project.

At the official end of the Al-Awda Project on Nov. 6, 1991, there were 696 wells on the report. The first well was secured on March 22, and the last fire was extinguished on November 6 for a total of 229 days. Remarkable!

Epilogue

The Kuwait story began, for me, in Jun. 1990. At that time, I was teaching a drilling practices seminar in London. I had six participants from Kuwait, two of which would later become part of the Kuwaiti Wild Well Killers (KWWK)—Kuwait's own firefighting team during the Al-Awda project. These were wonderful fellows. We endlessly discussed the situation in the Middle East. It was obvious they were not fans of Saddam Hussein and Iraq.

Shortly after our seminar ended, the Iraqi army invaded their homeland. As Iraqi journals would later reveal, within days of the initial invasion, the Iraqis began to deliberately and systematically prepare to destroy the Kuwaiti oil fields. Explosives were placed around the wellheads and wired to common points in order that one man could destroy many wells with the push of a button. Kuwaitis familiar with the oil fields were forced to help.

One of the major contributors to the planning and preparation for the Al-Awda project was Adel Sheshtawy, a native Egyptian and US citizen. Adel taught petroleum engineering at the University of Oklahoma from 1973 to 1978, roughly. In that capacity, he had many Kuwaiti engineers in his classes, and those engineers had moved into responsible positions within Kuwait Oil Company (KOC).

In addition, Adel had offered short courses in various petroleum engineering subjects. In one of those short courses, he had the opportunity to meet Saud Al-Nashmi. Ultimately, Saud became responsible for the Al-Awda project, battling the oil fires of Kuwait.

Soon after the invasion, Saud called Adel, and the two met in Houston. Everything was chaotic. There was a presidential directive that no one was to deal with a Kuwaiti or an Iraqi company. However, Saud had received reports from drilling operations that were continuing in Kuwait; explosives were being placed in some of the wells, and he was deeply concerned.

Mike Miller, president of Safety Boss, the Canadian well control group, recalled that Adel contacted him in late September or early Oct. 1990 to begin planning for the return to Kuwait. Mike recalls that at that time the estimated maximum number of fires was 50.

For a short period of time, the Kuwaitis made their headquarters at a hotel. KOC had a long association with the Houston-based company O'Brien Goins Engineering (OGE). W.C. "Dub" Goins and T.B. O'Brien were, even at that time, legends in the petroleum industry. Adel and several

Kuwaitis subleased office space next to OGE and began planning for the return to Kuwait. One of OGE's employees, Larry Flak, would later become the first coordinator of the Al-Awda project.

According to Mike Miller, there were at least four meetings in Houston during the fall of 1990, numerous telephone calls, and hundreds of hours of planning. The contracts were in place with the Kuwaiti government in exile in Taif, Saudi Arabia, but were not signed until the ground war broke out. Each group was responsible for bringing everything they needed to sustain a full year of operation. All of the contractors had a substantial degree of independence. The well control company had complete control in preparing the well for the kill operation.

In the fall of 1990, I was managing a relief well for the Mil-Vid #3 blowout near Vidor, Texas, for Amerada Hess. On the evening of Nov. 30, I was visited by Adel Sheshtawy and Fahed Al-Ajmi. Al-Ajmi is now a deputy director of KOC. Adel and Fahed were in my trailer house all evening, and we primarily discussed relief well options. Adel did most of the talking. We discussed state-of-the-art relief well technology. They seemed particularly interested in high angle/horizontal relief wells.

Adel was of the opinion that Iraq primarily wanted two things. The Kuwaitis had been drilling in the southern tip of the Rumaila field, which is one of the biggest fields in Iraq with only a small portion extending into Kuwait. Iraq felt that the Rumaila field was Iraqi and resented Kuwait's trespass.

Further, he said that Iraq's goal was to have access to a deepwater port in the Persian Gulf, and access had been offered via the Shatt al-Arab—the confluence of the Tigris with the Gulf. For those reasons, Adel believed there would be no war.

Adel went on to say that although it was generally accepted that there would be no war, a contingency plan had been prepared. It was well-known that Iraq had blown up oil wells during its war with Iran, and it was believed that similar operations were planned for the Kuwaiti oil fields. At that time, he did not let on that he suspected the wells were being wired for destruction.

The contingency plan, as Adel described it to me that evening, envisioned Iraq blowing up 120 wells, maximum. Kuwaiti officials in exile had contracted with four well control companies to furnish two teams each. Each team was to consist of a minimum of four men including a team leader. The companies were to furnish all the equipment needed to sustain a yearlong firefighting effort. The four companies were Red Adair, Boots & Coots, Wild Well Control—(all from Houston)—and Safety Boss, the Canadian company.

From the beginning and even during the planning phases, there was considerable resentment on the part of the Houston-based groups toward the Canadians. Although Safety Boss had been in business longer than any of the Houston companies, the Houston companies were much better known worldwide, thanks largely to the showmanship of Red Adair.

The Houston groups were all from the same gene pool. The Canadians had different ideas and presented a different perspective. As we shall see, the Canadians were unencumbered by the conventional Houston wisdom concerning firefighting and, as a result, were much more mobile and efficient in the Al-Awda project. This mobility and efficiency were the primary reasons that the Canadians handled almost 40% more fires than any of the Houston companies.

On 15 Jan. 1991, Adel's prophecies were disproved when Iraq failed to withdraw, and the war began. By the end of the war on Feb. 23, the withdrawing Iraqi forces had blown up more than 700 oil wells, far more than the contingency plan had envisioned.

The Kuwaiti government in exile immediately set about implementing their contingency plan and working frantically to expand it to include anyone and everyone that could help.

I received numerous clandestine calls in the middle of the night from someone claiming to be a member of the royal family of Kuwait or a special friend of the royal family with the authority to gain an audience and a contract. Everyone wanted to be my agent or special contact for Kuwait. Some even wanted money upfront to make the right connections. It was crazy.

The problem was basically this. The well control industry had never been large for the simple reason that there were never many blowouts and oil well fires. Myron Kinley dominated the business single-handedly until the late 1950s, and Red Adair continued that monopoly until the late 1970s.

The boom of the late 1970s and early 1980s created a demand for well control services that exceeded the supply. This excess demand resulted in a window of opportunity. In the late 1970s, Adair had a dispute with his two right-hand men, Boots Hansen and Coots Matthews, and they quit to form Boots & Coots. About the same time, Joe Bowden started Wild Well Control. In this same general time frame, Bob Cudd left Otis and formed Cudd Pressure Control.

The new companies were generally staffed with men that had worked for one of the older companies. One exception was Bob Cudd and Cudd Pressure Control. Although best known for his expertise in snubbing, Bob had considerable previous experience in oil well firefighting and capping operations.

Safety Boss was a Canadian firm established in 1954, which operated worldwide and was owned and operated by my old friend Mike Miller. However, within the industry at large, little was known about their operations. Safety Boss was started by Mike's father and was first active in lease fires. The company used more conventional firefighting techniques, including specially designed fire trucks with an ordinary appearance.

Each of the four firms selected as a part of the contingency plan had a small number of employees capable of managing a blowout. Pursuant to the contingency plan, each firm was to supply two (later three) full-time teams, which, in reality, meant four teams (later six) working 28-day rotations. Each team was to be composed of a minimum of four experienced men. That meant that each firm was to supply 16 (later 24) experienced firefighters. The branch of the industry that provided emergency firefighting services was not that large, and few personnel were available.

As a result, most of the firefighting companies were scrambling for warm bodies to fill the team requirements. The mystic veil surrounding oil well firefighting had been removed. There were roughnecks, engineers, snubbing hands, workover hands, school teachers, and bartenders, to name a few, working as firefighters. The bottom line was that most of the well fires in Kuwait were fairly simple and almost anyone could do it.

OGE was to provide the well control engineering. That meant that each firefighting team was assigned an engineer from OGE. The firefighting team was to extinguish the fire and cap the well. Then, the well control engineer was to kill the well and secure it for later recovery.

Another key organization was Santa Fe Drilling Company headquartered in Santa Fe Springs, California. Kuwait Oil Company had purchased Santa Fe Drilling Company in 1981 and had confidence in its management. Santa Fe Drilling was to provide support services for the firefighting effort. Specifically, each firefighting team was assigned a team of four or more heavy equipment operators and roustabouts. Ultimately, all teams would have backhoes, forklifts, and dozers at their disposal. The Santa Fe men would operate the equipment.

Bechtel, the large construction firm, had overall responsibility for providing support for the firefighting effort. Specifically, Bechtel was to provide housing, heavy equipment, cars, etc. From my perspective, two of the biggest areas of responsibility for Bechtel were water for firefighting and civil works for roads and road-building material.

Overall coordination and responsibility remained with officials of KOC. The primary burden rested upon Saud Al-Nashmi, who was a relatively young but very capable engineer.

When the war ended and the extent of the damage was revealed, the Kuwaitis were anxious to implement their contingency plan and to further expand the plan to include anyone else capable of contributing to the firefighting effort. The aforementioned infrastructure was not then well-known.

After scores of unsuccessful leads and hundreds of frustrating telephone calls, I finally learned that Ahmed Al-Khatib, a Palestinian national I believe, was the proper contact person within Santa Fe Drilling Company's office in Santa Fe Springs, California.

I contacted him, and it was clear that I was on the right trail. He told me that the Kuwaitis were currently looking for others to work in Kuwait on the well fires. He said there was a committee that screened everything and that the committee was moving to London. He went on to say that those interested were to send their information to him and he would pass it on with comments. After that, if the applicant was judged qualified, he would be invited for an interview.

I informed my old friend Bob Cudd, and we sent our information. Very shortly, an interview was arranged, and Bob and I went to California. On Tuesday, 12 Mar. 1991, we met with Ahmed Al-Khatib and John Alford at Santa Fe Drilling Company's office.

We were informed that the situation in Kuwait was much worse than expected and that KOC was anxious to identify everyone capable of contributing. They were particularly interested in identifying additional well control engineering services and oil well firefighting capabilities.

It was in this timeframe that I first heard about Neal Parry. Neal had begun his career with Santa Fe Drilling Company as a driller and had retired in 1988 as executive vice president, after 36 years of service. In his various capacities, he had spent considerable time in Kuwait and had gained the Kuwaitis' confidence. I would later get to know, work for, and greatly admire Neal. In a recent interview, Neal commented that his job in Kuwait was the highlight of his career. That comment from a man who ascended from driller to executive vice president of a large company speaks volumes about the Al-Awda project.

Mr. Al-Khatib told us that we had just missed Neal. He had left California to join the committee in London. That committee was to consider new technology and additional services.

On March 28, Neal called from London. He told me that Bob Cudd and I were to go to Kuwait and survey the situation. Since the airport had been bombed out and there were no commercial flights to Kuwait, we were to travel to Dubai and then go by charter to Kuwait City. We would spend a few days in Kuwait and then return to London to meet with the committee. The committee shared an office with Santa Fe Drilling Company near Victoria Station in London.

Bob and I left for London on Apr. 3. We went to Santa Fe's London office and met with the committee, which consisted of Ahmed Al-Awadi, Farouk Kandil, Mustafa Adsani, and Neal Parry. Jim Dunlap assisted Neal. We got our first insight into the conditions in Kuwait, but nothing could have prepared us for what we were about to see.

On Tuesday, Apr. 9, Bob and I traveled to Dubai and spent the night there. The next morning, we boarded an Evergreen Charter for Kuwait City. As we approached Kuwait City, the smoke from the fires became clearly visible. I had seen many oil well fires, but no one had seen 700 plus oil well fires packed into an area roughly 40 miles long and 40 miles wide.

I'll never forget landing at the airport in Kuwait City and seeing the devastation. There was a big bomb crater in the center of the runway. There was smoke and fire everywhere. Stan Petree, drilling superintendent with Santa Fe, met us and escorted us to our quarters. For the next several days, we toured Kuwait.

During those days, I took hundreds of photographs and hours of video. Even with all the photos and all the words in the English language, I am unable to describe what I saw. The worst was in greater Burgan field, where the well density is the highest (Fig. 1).

Greater Burgan is the oldest and largest field in Kuwait and one of the largest oil fields in the world. It is the crown jewel of Kuwait. The small city of Ahmadi, on the north end of Burgan, is the center of the oil field community. The Burgan highway runs south from Ahmadi to Gathering Center One (GC-1) and the Emir's Desert Palace.

In the middle of the Burgan field immediately adjacent to GC-1, the Emir's family had built a beautiful, luxurious palace complete with gardens, wild animals, and some of the finest horses in the world.

This symbol of Kuwaiti sovereignty at the end of the Burgan highway now lay in ruins among the fires (Fig. 2). My first trip down the Burgan

Fig. 1 Well fires in Greater Burgan field.

Fig. 2 Emir's Desert Palace after the war.

highway was sobering. The sun could not be seen. It was black as midnight. Oil rained down on our vehicle, reducing visibility to a few feet. There were oil wells on fire and ground fires everywhere I looked.

For most of the way, oil was halfway up our tires. I don't know why the heat from our SUV's exhaust didn't ignite the oil beneath us. I would later learn that the oil in Kuwait contains lower-end hydrocarbons and has a high-ignition point—a fact that served us well in the firefighting effort.

All along the highway from Ahmadi to Burgan, fires raged on both sides of the road. The smoke was so thick in places that I couldn't see the front of the car and couldn't tell we were on the road. I don't mind admitting it was a little scary. We turned around at the gathering center or what was left of it. All of the gathering centers were completely leveled (Fig. 3).

Later, I quizzed members of our military about the destruction of the gathering centers, and they were just as puzzled. One officer commented that evidence indicated intense heat. He was not sure whether the damage had been done by the allies or the Iraqis, but it looked almost nuclear to him.

The Iraqi destruction was senseless. They had sacked and destroyed the KOC headquarters in Ahmadi. They had stolen or destroyed every tool and vehicle in the Kuwaiti oil fields. Other than the equipment recently brought in by Bechtel or the firefighters, I did not see and could not find a piece of equipment that was operational. I did not even see any hand tools—no hammers, screwdrivers, and pliers, nothing.

On the lighter side, the camps housing the firefighters were fun. Those guys had gathered enough munitions to supply a small army! There were AK-47s, antitank guns, land mines, and every kind of bomb imaginable. I thought it a miracle that they didn't blow themselves up.

I went to one meeting conducted by our army. The topic for discussion was the various land mines we could expect. As the military ordnance expert

Fig. 3 Completely destroy oil gathering center.

showed pictures of the various mines and explained how dangerous they were, I could hear someone in the background telling his friends how he had two or three of those in his room.

In one instance, a crew decided to try out an Iraqi antitank weapon. The door was open on their pickup, and the brave soul holding the weapon was standing in front of the open door aiming at an abandoned tank. He fired, and his aim was true. However, the backfire from the weapon opened a neat hole in the door of his vehicle. The frightened crew waited until dark, returned to Ahmadi, got a backhoe, and buried the vehicle! The team leader later found out about the incident and reimbursed KOC for the vehicle.

On this trip, I met on numerous occasions with Miles Shelton, the local manager for Santa Fe Drilling Company. At that time, I got the distinct impression that Miles and perhaps others envisioned Cudd Pressure Control and the other newcomers working in the north of Kuwait, independent from the operation in Ahmadi. Santa Fe would supply support for the firefighters as Bechtel was doing in the south and GSM, my company, would provide the well control engineering. Certainly, that was consistent with the impressions I got in California. I heard that scenario on many occasions from different reliable sources, but personally, I don't think it was ever anything the Kuwaitis seriously considered.

On Apr. 16, Bob and I returned to London. We met with the committee the following day. We made our presentation and were told that it was just a matter of time before we would be working in Kuwait. On Apr. 20, we returned home to wait.

On May 9, I went to Trinidad to fix a blowout there and finished the job on May 17. Just as that job was finishing, I got a call from Bob Cudd that we had been summoned to London to negotiate the contracts. Consequently, I went directly from Port of Spain to London.

Around June 1, we returned to the US to wait. It seemed as though everything was moving in slow motion during that time. Bechtel could not or would not supply the teams working in Kuwait. Therefore, there was no need to bring in more teams.

In the meantime, I got a call from Ludwig Pietzsch in Germany. His group was interested in contributing in the new technology arena. At the end of June, I went to Frankfurt to meet with Pietzsch and his group. They had very interesting ideas involving laser-guided cranes, advanced jet cutting, and optics, which could see through the smoke and fire for a better look at the wellheads. I continued to work with Pietzsch and his group.

Unfortunately for them, the industry, and all of us, the project had been completed before any of their ideas could be tested. Undoubtedly, some would have made significant contributions to firefighting technology.

On Jul. 29, things began to happen. I was notified that Neal Parry had officially been named the new coordinator under Saud Al-Nashmi. Bechtel was behind, but the new teams were on their way. In addition, the international teams would be added. Bechtel was to supply the commercial teams, and the international teams would supply themselves. The British were to be in charge of all the work in Sabriyah, including the firefighting, and the French were to be working in Raudatain. Of course, neither the British nor the French companies had any firefighting capabilities. Consequently, they hired their hands off the streets of Houston or wherever they could. Nevertheless, they did some good work.

On Aug. 5, Neal Parry called and asked me to come to Kuwait to work for him on his management team. He said that he didn't claim to know anything about firefighting, but he did know how to get a job done. He said that I would be in charge of the field operations, and he would get me whatever I needed. He went on to say that the bad blowouts were ahead of us. He wanted the firefighters to cap and kill wells as fast as possible. He did not want any of the firefighting teams to bog down on one well. If a well proved too difficult, it was to be passed and left for later.

By that time, the wells around Kuwait City had been capped. The greatest challenge was Burgan field. In Burgan, the wells were very close together, the smoke was the thickest, oil lakes were everywhere, and ground fires raged. Burgan was to be my responsibility.

It was recognized that the vast majority of wells would be classically extinguished, capped, and killed. However, it was generally believed at that time that there would be many wells that would require much more time, energy, and effort. Some, it was thought, would require relief wells. In the event that wells of that nature were identified, it was my job to plan the well control strategy and ultimately conquer the last wells.

I asked Neal how long the project would last. He told me to plan on staying five years and taking a field break every 90 days. On Saturday, 10 Aug. 1991, I kissed my family goodbye and left for Kuwait. I arrived in Kuwait City on Aug. 12.

My room was in the Ahmadi House. It had been used since March by the firefighters, and the floor and rug were black from oil, mud, and soot. My first impression was that the project was in chaos. There was no coordination or organization. Everyone was running around like a bunch of loose cannons. In general, the firefighters simply worked on the wells they wanted to work on, when and where it pleased them.

There were several different firefighting strategies. The disciples of Red Adair operated in essentially the same manner. They would set at least two large, skid-mounted, diesel-powered centrifugal pumps on the edge of the 25,000 bbl lagoon. An 8–12 in. flanged line was run to a staging manifold. The fire monitors were shielded using reflective tin. All of the plumbing was screwed or bolted together. It was very time-consuming to move in on a fire. Some, like Cudd Pressure Control, used irrigation piping that was lighter and more easily assembled. Everything had to be loaded on trucks to be moved very far.

Safety Boss, the Canadian Company, used specially designed fire trucks. Their water was hauled by transport and stored in 500 bbl frac tanks. The Canadians wore fire-retardant coveralls and bunker suits when necessary. As a result, they routinely worked closer to the fire and used less water. They used conventional fire hoses to connect their pumps to their monitor houses. As a result, they were very mobile and flexible. They could drive to a fire, roll out their hoses, and be working in a manner of minutes. At the end of the day, they would roll up their hoses and drive the truck to Ahmadi. In addition, they used more fire-retardant chemicals than the Houston-based firefighters.

There were advantages to their mobility and flexibility. When the wind shifted, the exposed equipment would be soaked with oil. As a result, it could not be operated until the steam cleaners had removed the oil. Since the fire trucks were driven to town each evening and washed if necessary, they were ready to go to work the next morning.

Their mobility was an advantage in some instances. In one instance, using the existing pipelines, I simply couldn't get sufficient water to fill the lagoon at a well on the far west side of Burgan. I asked Mike Miller and his Safety Boss crew to fix it. It was fixed in less time than it would have taken the conventional firefighters to unload their trucks. In my opinion, these advantages were primarily responsible for the fact that although the Canadians started several weeks later than everyone else, they accounted for 40% more wells than any of the other original four. The Canadians, as a result of their effort, and Cudd Pressure Control, as a result of the dedication of Bob Cudd, were the only companies retained after the Al-Awda project for the postcapping operations.

The basic strategy for most of the teams was the same. They would work to get the fire burning straight up and then extinguish the fire. After the fire was extinguished, the well would be capped.

The international teams used a variety of techniques. The Eastern Bloc countries such as Romania, Hungry, and Russia used fire trucks, powder trucks, and jet engines. Typically, one or more jet engines were mounted on a truck or tank and would be used to literally blow the fire out. The Hungarian "Big Wind" was the most spectacular (Fig. 4).

I routinely kept the newcomers on the edge of Burgan and out of the way until they gained experience and demonstrated their abilities.

When I got there, the Houston-based firefighters were working primarily in the areas around Ahmadi. The Canadians were working in the south of Burgan. As the prevailing wind was from the north, the Canadians were always working in the thick, black smoke, while the Houston group was working in the sunshine. The resentment and discrimination only served to inspire the Canadians.

As I got organized, it was abundantly clear that the biggest problem was the water supply. Bechtel was a zoo. They had notebooks of organization charts. On one of the first days, I went through the organization charts trying to find out who was responsible for the water supply. I even went to Bechtel's headquarters and went from office to office. No one seemed to know who was in charge of anything. Most were sitting around reading a newspaper. On that day, I was unable to determine who was responsible for the water supply. It was frustrating.

Fig. 4 Hungarian "Big Wind" for blowing out the fire with jet engines.

A little later, I was in the field and met a very pleasant New Zealander named Randy Cross. Randy was very capable and seemed to have field responsibility for supplying water and locations. I wasn't sure what his job was but I soon learned he could get a lot done. He did a remarkable job.

The decision had been made to use the existing pipeline system to pipe water from the sea to a lagoon at each well. That was not the best idea. With all of the bombs that had been dropped, the pipelines were in poor condition. When we turned the water on, it looked like a giant sprinkler system. Randy maintained that it would have been more efficient to build a new system.

I learned that Randy had a big and vital job. He was responsible for restoring the roads, preparing the location, digging and lining the lagoons, and filling them with water. His job was to stay ahead of the firefighters. My challenge and motto became "Catch the Kiwi!"

As we worked into Burgan, Randy was having difficulty keeping ahead of us. He came to me one day with a problem. He needed to open a road into the heart of Burgan. He needed the road in order to build a material pit for roads and locations. He also needed it for access to the pipelines.

Since I needed someone with mobility, I turned to my old friend Mike Miller with Safety Boss. We surveyed the road Randy wanted opened. There were oil well fires, ground fires, oil, and smoke everywhere. Many of the oil well fires were immediately adjacent to the road Randy wanted opened. Accepting the challenge would mean Mike and his men would have to work in the raining oil with fires all around them and in thick smoke. Mike never hesitated for a second. He said that if it had to be done, he would do it.

Mike and his men went to work. They worked on some tough fires under the most adverse conditions. Their equipment was uniquely suited for this type of operation. They could drive their fire trucks to the location, set up, and be spraying water on the fire in about an hour. At the end of the day, they could roll up their hoses and drive their equipment to Ahmadi. A minimal amount of equipment was left unattended and exposed. The road was opened in what seemed like record time. I visited their operation daily. It was a miracle to me that they could continue—but they did.

If there were any heroes in Kuwait, Randy Cross would have to be at the top of the list. The recovery effort in Burgan was organized such that the firefighters had the wind to their backs. That meant that Randy and his men had to work in the smoke and ground fires rebuilding roads, preparing locations, digging pits, and restoring pipelines.

The smoke was so thick that visibility was zero every day. The oil rained down so badly that I had to have my car washed almost daily. Ordnance had to be cleared. Randy did his work using Filipino labor. They hauled 1500 loads of road material each day and sometimes as many as 300 loads a night.

On a list of heroes, the men clearing ordnance would also have to be at the top. The British Royal Ordnance cleared in Burgan. There was only one way to do it. They had a seat on the front fender of several Land Rovers. They would mark off grids and then drive the grids. Those poor guys would show up at the mess hall for lunch, and their vehicles would be black with oil. They would be soaked from head to foot. I don't know how they survived. Some of them didn't. Some of them were killed by land mines.

Royal Ordnance would clear and mark a road and location. It was best to stay within the perimeter as marked. There were unexploded bombs and mines everywhere in the desert. That more were not injured or killed is a testimony to the good work of these guys. I know that often when the ground fires broke out in a new area around a well; it would sound like the 4th of Jul.

When an ammunition dump was located, ordnance would call on one of the explosives experts with the firefighters to light it up. They would come around and advise that there was going to be an event at a particular time and everyone in the vicinity was to take cover 5 min prior to the scheduled event. One of those poor guys had to remain within 100 yards of the scheduled event to make sure no one inadvertently wandered into the area. When one of those dumps went up, it was spectacular. I don't know how the watchman survived. It would shake the ground for miles (Fig. 5).

After about one month, Bechtel opened up the Latifa Towers, and all of the firefighters moved into them. The Latifa Towers were two 17-story apartment buildings overlooking the Gulf. Bob Cudd and I shared a three-bedroom suite on the 16th floor of one of the towers. We had news channels and movies. A large mess hall was built across the road, and we ate there.

Shortly after arriving, I felt we would be finished by Easter, 1992. A little later, I told my wife I'd be finished by Christmas. After a few more days, I thought we would be finished by thanksgiving, 1991. It was simply a matter of getting organized and going to work.

The next few months were a blur. We got up every morning at about 0400, had breakfast and went to work. We finished about 1700, went to the Towers, showered, had dinner, went to bed, and did it all over the next day. Pretty soon, I didn't know what day it was, or even what month it was.

Fig. 5 A munitions dump being destroyed in the background.

Neal was true to his word. After he got there, we got everything we needed. He truly knew how to manage a project. Oil well firefighters are well-known for their egos and independent ways. I don't think anyone else could have commanded their respect and kept them moving together in the right direction.

By the middle of October, it was apparent that the project was progressing more rapidly than anyone had imagined. At this point, I was fearful that someone would become overconfident or careless and make a fatal mistake. To that point, there had been no serious injuries, and we were determined to maintain the high safety standards.

One of the most dangerous times in the firefighting was when the wind changed direction. The vast majority of the time the wind blew strongly from the north. Occasionally, the wind direction would shift from the north. On those occasions, the wind just seemed to swirl around without direction. Consequently, the oil would swirl, soaking the ground and all of the exposed equipment.

Late one afternoon, the north wind died. We all knew what that meant. The Rumanian team had been working on ground fires. When the wind died, they were in the process of shutting down for the night when suddenly a ground fire backfired and engulfed one of their crews. Two of their men were badly burned.

Our safety net was excellent. We were able to transport anyone who was injured to the hospital in Ahmadi in less than 15 min. I recall that when I visited the injured Rumanians, their faces were badly burned and swollen. They were stabilized and airlifted to Europe. Unfortunately, both men later died as a result of their injuries.

Things did continue remarkably well. I reported to Neal on 2 Nov. 1991. "It is my pleasure to inform you that there are no fires burning in the Burgan Field!" We finished the project and scheduled the closing ceremony for 6 Nov. 1991. Together with the Kuwaiti firefighters, BG 118 was equipped to be the "last" fire in Kuwait. The Emir would extinguish it himself at the closing ceremony. A platform was built about 100 yards away from the burning well, and a special control panel was installed. Neal told me that when the Emir flipped the switch, that fire had better go out or my butt was toast!

The closing ceremony was a sight to behold. Huge tents (Fig. 6) were set up in the desert to house the many dignitaries who came from everywhere. There was an abundance of food, music, and dancing. The Kuwaitis were dressed in their finest traditional attire (Fig. 7)—an interesting sight to us Westerners. There were numerous speeches and many ceremonies. Finally, the Emir made his appearance. All of us in the firefighting got to pass by for review and shake the Emir's hand as a token of his gratitude.

All the while BG 118, burning in the background, was a focus of attention. Then, the final moment came, and the Emir stepped to the platform.

Fig. 6 Tents set up in the desert at the closing ceremony.

Fig. 7 Closing ceremony with the BG118 well burning in the background.

I held my breath as he reached for and flipped the switch. The last fire in Kuwait went out without a whimper. Thunderous applause accompanied loud cheering. The Al-Awda project was finished.

Fortunately, everything had gone better than planned. I returned home just before thanksgiving, 1991. Hopefully, it was a once in a lifetime experience—perhaps even a once in the history of the world event. It was a wonderful example of what men from many different cultures can overcome when they work diligently together. We did a good job, and I'm proud to have been a part of it! I wouldn't have missed it.

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SECOND EDITION

BLOWOUT AND WELL CONTROL HANDBOOK

ROBERT D. GRACE

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About the Author

Robert D. Grace is currently President and CEO of GSM Enterprises and Subsidiaries headquartered in Amarillo, Texas. Bob founded GSM in 1976, and it is the oldest consulting engineering firm in the industry dedicated to oil field operations. Bob has more than 50 years of onsite experience in the oil fields of the world. Although he holds a BS and MS in Petroleum Engineering from the University of Oklahoma, his passion has always been in field operations and the application of engineering principles to field operations. He was the first wild well control engineer and the first to bring engineering technology to the control of blowouts. He pioneered modern relief well technology. For more than 40 years, he has served as a consultant in well control, blowouts, and fires. In addition to being a well control expert, he has specialized in supervising and solving some of the most complex blowouts the industry has known, including the largest blowout in Texas history. As a part of the management team for the Al-Awda Project, the oil fires of Kuwait following the 1991 Gulf War, he was responsible for the Burgan Field, the world's second largest oil field. He was also consultant on the Deep Water Horizon incident in 2010. He has authored numerous books and technical papers, lectured worldwide for more than 40 years in drilling practices and well control, and is a registered professional engineer.

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