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MANAGED PRESSURE DRILLING

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- Editors



Developed under the auspices of the IADC Technical Publication Committee

Managed Pressure Drilling

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Houston, Texas

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The mission of the IADC Technical Publications Committee is to publish a comprehensive, practical, and readily understandable series of peer-reviewed books on the petroleum drilling industry known as the *Gulf Drilling Series* in order to educate and guide industry personnel at all levels.

This book has been peer reviewed in accordance with this mission by:

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Ken Malloy, Stress Engineering
Bill Maurer, retired, Maurer Engineering
Jay Smith, Viking Engineering

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Preface

Since the early 1970s, a loosely organized technical group of oilfield personnel from both operators and service companies has made a consistent effort to write and publish technical information. The group, initiated by Dr. Leon Robinson, then of EPR, started by trying to establish some logical rules for shale shaker screens and progressed to the general subject of solid control for drilling fluids.

In 2006, the publisher of Gulf Publishing Company approached the group and asked if it would be interested in developing a series of technical books that detailed modern drilling technology. With the “big crew change” in progress, the industry was in danger of losing some of its basic hard and expensively learned technology. After some discussion, the renamed IADC Technical Publications Committee agreed to undertake the project: some 10 or 15 technical books, with some organizational and administrative help from the IADC and publishing rules and marketing efforts by Gulf Publishing Company. The basic premise of each book was that it was to briefly review the past technology and present the present technology and practice in such a way as to be useful to the operating engineer, the rig supervisor, and students of the subject. The subject matter was to be limited to the technical subject involved, with enough discussion of ancillary material that the reader understood the basics of the subject. Other books in the series would cover those and other technical subjects.

A list of technical subjects was developed, along with some general presentation rules; and authors and technical editors were solicited. Each book was to be the responsibility of a senior author, who would arrange for additional help from other general or chapter authors.

This is the second book of the series. Managed pressure drilling (MPD) is a method of drilling in a balanced or overbalanced state

while threading the pressure limit between pore pressure or well-bore stability and fracture pressure. MPD seeks to avoid a well kick.

The precise technologies of MPD were first put in practice within the five to seven years prior to the publication of this book. The general information about MPD is well documented in SPE technical papers and in the IADC Underbalance and Managed Pressure Drilling Workshops. Actual operational procedures about the effect of such items as pump-rate changes, well-bore ballooning, pipe movement, and trips are less well documented. These items are the critical element of actual operations, and the knowledge is resident only in the people who have actually done it. Since no one has seen it all and done it all at this early stage in managed pressure operations, it is evident that to present and publish that information, the principal author would have to go to the people with the most field experience or special abilities.

We sought out the people most knowledgeable and experienced in the various subjects as chapter authors. Since this is new technology, many of those individuals are with the service organization marketing the technology or associated equipment. Each chapter retains some special views of the service company and often the passionate views of the chapter author. There is also a significant amount of overlap in all the chapters. Field operations do not take place in a vacuum, and in actual practice, most of the techniques tend to approach a common point. The principal authors attempted to homogenize some of the styles and illustrations (and commercial comment) without taking out the special flavor of the most knowledgeable writers. Despite, or perhaps because of, their parochial views, we are all indebted to the drilling specialists who took the time to write and advise on the content of this book. It would not be possible to present the insight into the various operations without them. I would like to give special recognition and thanks to Don Hannegan of Weatherford, who spent an inordinate amount of time explaining many of the issues about which I was unclear. Although he was not listed as an author, his influence in the book was not insignificant. I would also like to thank Ken Malloy of Mohr Engineering for critical comments or organization that helped change the outlook of the entire book.

Words do not always portray exactly the same idea to all people. But all of us have done our best to make the information clear and straightforward.

The book has been technically reviewed by independent, knowledgeable individuals not associated with any of the authors or the book group. The technical reviewers have generally been members of the IADC Underbalance and Managed Pressure Drilling Committee, who worked on their own time to help us. We are indebted to them for pointing out errors in clarity and technology. However, the reviewers of this book do not represent the IADC Underbalance Operations and Managed Pressure Drilling Committee, and the committee has not reviewed this book.

—*Bill Rehm*

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Contributors

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Erdem Catak is a project engineer for Secure Drilling. Currently, he is responsible for assisting the development and introduction of Secure (managed pressure drilling) in the field, supervising field applications, preparing training materials, teaching rig crews and drilling engineers how Secure works, reviewing potential well candidates with clients, and promoting the method in conferences, exhibitions, and meetings. Before joining Secure Drilling, Catak worked for the Louisiana State University Petroleum Engineering Research and Technology Transfer Laboratory as a coinstructor and trained rig personnel on advanced hands-on well control methods. He taught drilling fluids and well control classes at LSU, where he earned his MS degree in Petroleum Engineering. He also taught classes at Istanbul Technical University, where he graduated with an honors degree in Petroleum and Natural Gas Engineering. Catak is a member of SPE, IADC, and AADE, and a lifetime member of Pi

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John Cohen worked in research and development in the oil industry since his graduation from the Colorado School Mines in Golden, Colorado. His degree in Mineral Engineering Physics has given him a unique view and allowed him to work on a variety of projects over the past 35 years. Cohen has significant experience in developing and improving down-hole tools, including roller cone and PDC drill bits, turbodrills, mud motors, turbine generators, MWD tools, rig instrumentation, and rotary steerable tools. He has also worked on subsea equipment, including riser design, collet connectors, and subsea pumping systems. Cohen was director of a drilling laboratory, where he developed methods and apparatus for testing oilfield equipment, down-hole tools, and drilling concepts. Included among these was the testing of fluids for a unique method of dual-gradient drilling. This interest in new technology and dual-gradient drilling continues, with work on subsea pumps and concepts for dual-gradient and riserless drilling.

Brandee Elieff is a drilling engineer in the U.S. drilling group at ExxonMobil Development Company in Houston. She earned a BS degree in Petroleum Engineering from Texas A&M University in 2004. She further earned an MS degree in Petroleum Engineering from Texas A&M University with a Drilling Engineering focus and an MS degree in Petroleum Economics and Management from the Ecole Nationale Supérieure du Pétrole et des Moteurs (Institut Française du Pétrole) in 2006. She has been working for ExxonMobil Development Company since 2006, where she has worked offshore in West Africa and on land in the United States.

Paul Fredericks works for At Balance in Houston and has 30 years of international and domestic oilfield experience, ranging from

open- and cased-hole wireline, measurement, and logging while drilling and managed pressure drilling. His career spans field operations, log analysis, technical support, operations and product line management, and marketing. Fredericks joined At Balance as director of marketing in 2005 and directs all activities related to marketing, advertising, sales support, and communications for the company and its products and services. His technical articles have been published and presented for various professional organizations including the SPE, IADC, and SPWLA. He graduated from the University of Mississippi with degrees in Geology, Physics, and Mathematics.

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Jim Hughes has 28 years' experience in all phases of the upstream oil and gas business. His first 9 years were devoted to drilling and production operations, prospect generation, and acquisitions under the tutelage of David K. Davies, his first employer and mentor, who taught him extensive completion design practice using formation-damage prevention techniques. Over the next 10 years, Hughes developed and utilized short radius, multilateral underbalanced horizontal drilling (UBHD) technology as a primary completion and recompletion method to improve productivity. After several years of research and development and purchase of his own drilling rig, in 1991, Hughes, using an air hammer, drilled the first horizontal lateral well from a short-radius (25-ft) curve. Over the next 3 years, he spent most of his time evaluating reservoirs for the recovery of bypassed reserves, using UBHD technology as a completion technique. During this time, he was in Oman as part of the first independent technical team invited to recommend well construction methods and evaluate indigenous oilfields for redevelopment, using

UBHD technology as a completion technique. Hughes has devoted most of the last 10 years to patenting new technologies related to UBHD, including a new short-radius self-steering bottom-hole assembly, an artificial lift-while-drilling process for managed pressure drilling, and smart drill pipe. He currently holds 12 patents related to UBHD. He is a graduate of the University of Missouri with a BS degree in Geology.

George Medley is the executive vice-president of Signa Engineering Corporation and has over 30 years in oil and gas operations and R&D. Along with extensive drilling, completions, and operations management, he has managed R&D projects for the U.S. Department of Energy, the Gas Research Institute, and the Drilling Engineering Association. He developed multiple training courses in unconventional drilling techniques. Medley holds a BS degree in Civil Engineering from Texas A&M University and received one of five regional SPE International Drilling and Completion Engineer awards for 2005–2006.

Dennis Moore received a BS degree in Petroleum Engineering from Texas A&M University. Since then, he has worked for major oil companies, independent operators, and consulting engineering companies, serving in a variety of drilling, production, and reservoir engineering positions worldwide. These jobs provided him with a diversity of both engineering design and well site supervision experience on HPHT, horizontal, underbalanced, and managed pressure projects, including drilling with casing and with coiled tubing. He has 30 years' experience in the oilfield, authored or coauthored several articles on underbalanced and managed pressure drilling, and is a registered professional engineer in Texas. He currently is the vice-president of international managed pressure drilling with New Tech Engineering, based in Houston, and can be reached via email at dennisdmoore@yahoo.com or by phone at 281-687-8584.

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Bill Rehm, the principal author for *Managed Pressure Drilling*, is a drilling consultant in and the author of *Practical Underbalanced Drilling and Workover*. He has some 30 years' experience in underbalanced drilling, starting with some of the early foam drilling on the AEC site in Nevada and foam workover in California, up through experiences in Canada and present-day operations with gaseated fluids in such diverse areas as the Austin Chalk, Illinois, and California. In his broad experience, he was an early contributor to well-control technology and chief engineer for a service company when drilling chokes were first being introduced as a method of controlling well pressure. As general manager of a directional drilling company, in the early days of learning in the Austin Chalk, he participated in the development of many of the ideas that lead to today's underbalanced and managed pressure drilling. At present, he is active as a consultant in coal-bed methane and is actively engaged in corrosion control and foam workover in Wyoming. He holds several patents and has written more than 50 publications on the subjects of well pressures, well control, horizontal drilling, and underbalanced drilling. He can be reached at rehm@earthlink.net.

Jerome Schubert has a BS (1978), MEng (1995), and PhD (1999) all in Petroleum Engineering from Texas A&M University and is currently an assistant professor and Larry Cress Faculty Fellow in the Harold Vance Department of Petroleum Engineering at Texas

A&M University. Schubert has worked as a drilling engineer for over eight years with Pennzoil Company and Enron Oil and Gas, over four years as a well-control instructor with the University of Houston/Victoria Petroleum Training Institute, and as a faculty member at Texas A&M University since 1994. At Texas A&M University, he is involved in teaching graduate and undergraduate drilling courses. Related research activities with which Schubert has been involved include kick detection, well kill procedures, shallow-water flows, underbalanced drilling, managed pressure drilling, evaluation of the conductor casing setting depth in shallow water, risk assessment of surface BOPs and high-pressure risers on MODUS in the Gulf of Mexico, and development of well-control procedures for dual-gradient drilling. He also serves on the IADC Training and Well Control Committees and the IADC WellCAP Review Panel. Schubert is a member of Pi Epsilon Tau and Sigma Xi and was on the Subsea Mudlift JIP Well Control Team. He is author or coauthor of over 30 conference and journal papers as well as the holder of three dual-gradient drilling patents.

Roger Stave, currently president and chief technical officer of AGR Subsea, Inc., has a vast breadth of oil and gas drilling and design experience, covering a career of over 30 years. He worked with a major operating company in the North Sea, managing projects and supervising technology developments for a variety of new projects, and performed many high-profile consulting roles. He most recently has been instrumental in developing the Riserless Mud RecoveryTM (RMR) system, dual-gradient drilling techniques, and other enabling technology for deepwater drilling operations, all of which are operational around the world, with consistent success. His contribution to many of the major offshore projects in the Norwegian sector of the North Sea during a very productive period of new production and platform design, construction and installation, and development of gas injection, modifications, and new technologies primarily for offshore deployment, enables him to combine an innovative and commercially successful contribution to the petro-

leum industry. He has presented papers around the world and is the originator of six patents.

Rod Vogel has over 20 years of diversified oilfield experience, varying from oil company reservoir engineering to service company operations management. Vogel began his career with Marathon Oil Company in the United States, where he held various positions in reservoir, operations, and drilling and also specialized in stimulation fluids and horizontal drilling. He participated in engineering the production turnaround of the 4-billion barrel Yates field in the early 1990s and the implementation of Marathon's short-radius horizontal drilling program. In 1993, he left Marathon to found and manage a horizontal drilling company, specializing in short-radius and underbalanced drilling. Vogel joined a Weatherford company in Aberdeen, Scotland, in 1997 and held several international positions, managing underbalanced drilling operations and projects across the eastern hemisphere. He joined National Oilwell Varco in 2003 and is presently director of global rental operations, based in Houston. Products and services in his group include the CCS (continuous circulation system), PCWD operations (Shaffer's rotating annular BOP), and rentals of other rig equipment including top drives and iron roughnecks. He holds a BS in Petroleum Engineering from Pennsylvania State University and an MBA from the University of Texas.

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List of Abbreviations

APL	Annular pressure loss
BHA	Bottom-hole assembly
BHP	Bottom-hole pressure
BML	Below mud line
BOP	Blow-out preventer
BPD	Balanced pressure drilling
CBHP	Constant bottom-hole pressure
CBP	Constant bottom-hole pressure
CCS TM	Constant circulating system
CIV	Casing isolation valve
D	Depth
D	Diameter
DAPC TM	Dynamic annular pressure control
DDV TM	Drilling down-hole deployment valve
DG	Dual gradient
DGD	Dual-gradient drilling
d_b	Diameter of the hole
d_p	Diameter of the (drill) pipe
DSE	Dual-sided elevator
DSV	Drill-string valve (subsea); see HCV
ECD	Equivalent circulating density
ECD-RT TM	ECD reduction tool
EMD	Equivalent mud weight (density)
FBP	Formation breakdown pressure
FCP	Final circulating pressure
FIT	Formation integrity test
FS	Formation stability pressure; see P_{wbs}
H	Height of a column of mud or water

HAZID	Hazardous conditions identification
HAZOP	Hazardous operations plan
HCV	Hydraulic control valve; see DSV (subsea)
HPHT	High temperature, high pressure
HPU	Hydraulic power unit
HMI	Human/machine interface
IADC	International Association of Drilling Contractors
ICP	Initial circulating pressure
ICU TM	Intelligent control unit
JIP	Joint industry project
K	Consistency index (drilling fluids)
KRP	Kill-rate pressure
KWM	Kill-weight mud; see W_2
L	Length
LC	Lost circulation
LMRP	Lower marine riser package
LOT	Leak-off test
LWD	Logging while drilling
MCD	Mud cap drilling
MD	Measured depth
MDU	Mud diverter unit
MLP	Mud-lift pump
MPD	Manged pressure drilling
MW	Mud weight (density)
MWD	Measurement while drilling
N	Flow behavior index
NPD	Nonproductive time
N_{re}	Reynolds number
NRV	Nonreturn valve (check valve)
OBM	Oil-based mud
OMW	Original mud weight; see W_1
P	Pressure
P_{bp}	Surface back pressure
PCWD TM	Pressure control while drilling
P_{ds}	Differential sticking pressure

P_f	Fracture pressure
P_{fg}	Fracture pressure
P_{lc}	Lost circulation pressure
PMCD	Pressurized mud cap drilling
P_p	Pore pressure
P_{po}	Pore pressure
PV	Plastic viscosity
P_{wbs}	Well-bore stability pressure; see FS
PWD™	Pressure while drilling
QTV™	Quick trip valve
R	Gas constant
R_{600}, R_{300} etc.	VG meter readings at 600 and 300 rpm
RBOP™	Rotating blow-out preventer
RCD	Rotating control device
RMR	Riserless mud recovery
ROV	Remote operating vehicle
SCM™	Suction control module
SFL	Sacrificial fluid
SG	Specific gravity
SICP	Shut-in casing pressure
SIDPP	Shut-in drill-pipe pressure
SMD	Subsea mud-lift drilling system
SRP	Slow-rate circulating pressure
T	Temperature
TDCT	Top-drive connection tool
TVD	(True) vertical depth
v	Velocity
v	Volume
W_1	Initial mud weight (density)
W_2	Final mud weight (density)
WBM	Water-based mud
WD	Water depth
YP	Yield point
Z	Gas Z factor
Δ	Change in function

ρ	Density of mud weight
ρ_m	Density of mud
ρ_w	Density of water
ρ	Stress
μ	Viscosity
μ_{app}	Plastic viscosity; see PV

CHAPTER ONE

The Why and Basic Principles of Managed Well-Bore Pressure

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About This Chapter

This chapter is an introduction to the content of the book. In this chapter, managed pressure drilling is defined to clearly state the book's objective. Then, the benefits of managed pressure drilling are explained. At the end, basic well control and pressure regimes in the well bore are defined to provide the background required for understanding the other chapters.

1.1 Introduction to Managed Pressure Drilling and Some Definitions

Managed pressure drilling (MPD), as a discipline or drilling technique, is the result of the high costs of nonproductive time (NPT) caused by the close proximity between pore pressure and fracture pressure. This problem is often associated with marine drilling in soft sediments, but it also can be a problem in land drilling.

MPD is a general description of methods for well-bore-pressure management. MPD includes a number of ideas that describe techniques and equipment developed to limit well kicks, lost circulation, and differential pressure sticking, in an effort to reduce the number of additional casing strings required to reach total depth (TD).

The field of well-bore pressure management has broad application in the drilling industry and provides solutions to problems in

- Extending casing points to limit the total number of casing strings and the subsequent hole size reduction.
- Limiting the NPT associated with differentially stuck pipe.
- Avoiding the lost circulation–well kick sequence.
- Limiting lost circulation.
- Drilling with total lost returns.
- Increasing the penetration rate.
- Deepwater drilling with lost circulation and water flows.

The International Association of Drilling Contractors (IADC) Subcommittee on Underbalanced and Balanced Pressure Drilling has made the following formal definition of *managed pressure drilling*: “Managed Pressure Drilling (MPD) is an adaptive drilling process used to more precisely control the annular pressure profile throughout the well bore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. This may include the control of back pressure by using a closed and pressurized mud returns system, downhole annular pump or other such mechanical devices. Managed Pressure Drilling generally will avoid flow into the well bore.”

Not in the formal definition but implied is that this drilling method uses a single-phase drilling fluid treated to produce minimal flowing friction losses.

“MPD’s ability to dramatically reduce NPT in today’s high rig rate market makes it a technology that demands consideration in any drilling or development program. MPD helps manage the problems of massive losses associated with drilling fractured and

karstic carbonate reservoirs. It also reduces ECD [equivalent circulating density] problems when drilling extended reach wells and wells with narrow margins between formation breakdown and well kicks. In long horizontal sections, reducing ECD helps mitigate the impact of drilling fluid induced impairment that is amplified by high overbalance.” The definition is unique (an adaptive process) in that it proposes that the drilling plan is not only changeable but will change as the conditions in the well bore change.

The basic techniques covered under MPD are

- *Constant bottom-hole pressure* (CBHP) is the term generally used to describe actions taken to correct or reduce the effect of circulating friction loss or equivalent circulating density (ECD) in an effort to stay within the limits imposed by the pore pressure and fracture pressure.
- *Pressurized mud-cap drilling* (PMCD) refers to drilling without returns to the surface and with a full annular fluid column maintained above a formation that is taking injected fluid and drilled cuttings. The annular fluid column requires an impressed and observable surface pressure to balance the down-hole pressure. It is a technique to safely drill with total lost returns.
- *Dual gradient* (DG) is the general term for a number of different approaches to control the up-hole annular pressure by managing ECD in deepwater marine drilling.

1.2 History

A number of the techniques under the present name of *managed pressure drilling* are not new. As individual items, many have them have been around for many decades. Rotating heads were described in the 1937 Shaffer Tool Company catalog. The ECD was effectively used in well-control practices developed in the 1970s. The present technology combines and formalizes new techniques with those historically used to deal with some of the most common drilling problems, such as well kicks and lost circulation.

1.2.1 Old Ideas Made New

Many of the ideas on which MPD is predicated were first formally presented in three Abnormal Pressure Symposiums at Louisiana State University between 1967 and 1972. These symposiums looked at the origin and extent of abnormal pressures and how to predict pressures and fracture gradients from available data.

In the 1970s, a major oil company, out of its New Orleans office, was drilling from “kick to kick” in offshore Louisiana to increase drilling rate and avoid lost returns. This was a clear case of managed pressure drilling in the Gulf of Mexico.

Mud-cap drilling (MCD) was common for years as “drilling dry” or “drilling with no returns.” A more formalized version of MCD was tried in Venezuela in the 1980s, in the Hibernia Field off Nova Scotia in the 1990s, and later in Kazakhstan, in the former Soviet Union.

Efforts in the 1990s in the Austin Chalk in Texas to drill thousands of high-pressure gas wells with total lost returns led to pressurized mud cap drilling.

1.2.2 New Ideas

With the formalization of some of the older techniques, new techniques have been added:

- Using surface impressed pressure with a light mud to compensate for ECD.
- Continuous circulation in pressurized containment systems.
- Dual-gradient proposals for drilling in the ultradeep offshore waters where a subsea pump is used to pump the drilling fluid up from the seafloor.
- Down-hole valves to allow trips under pressure without stripping.

1.3 Advantages and Methods of Managed Pressure Drilling

The primary advantage of managed pressure drilling is to reduce drilling costs due to NPT while increasing safety with specialized

techniques and surface equipment. In deep water, many projects would not be economically viable without MPD techniques.

A number of significant and recurring problems have increased drilling costs since the first rotary records were kept. These problems do not exist in a vacuum, where they alone are a problem, but for the most part are interrelated and often occur at the same time. The relationship of the problems shifts as drilling moves offshore, into very deep water, depleted fields, or super-deep wells. It is difficult to rank the problems, because each drilling province has its own particular series of events and each decade brings different problems to the fore.

Figure 1.1 illustrates statistical causes of NPT in the Gulf of Mexico between years 1993 and 2003 for gas wells. About 40% of NPT, a significant percentage of drilling problems, are because of pressure-related issues, such as lost circulation, kicks, and well-bore

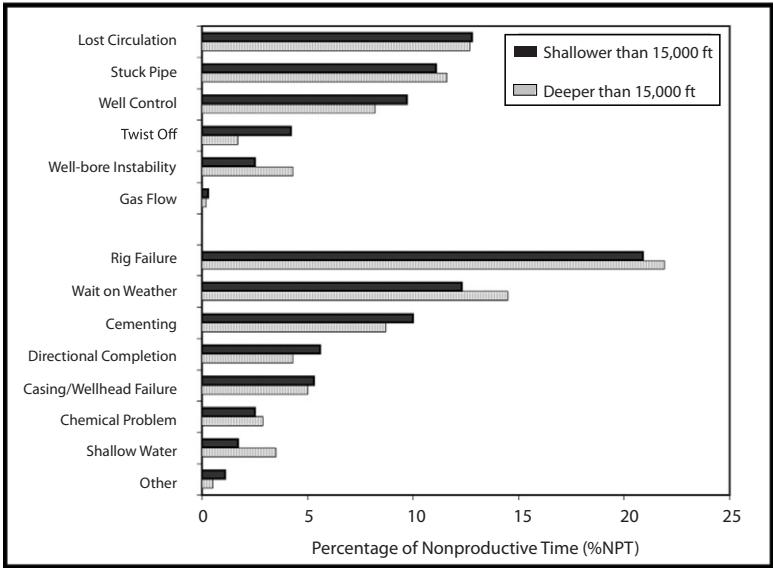


Figure 1.1 Records of gas wells drilled in the Gulf of Mexico from 1993 to 2003 indicate that 40% of the NPT is related to the drilling operation and procedure. (Courtesy of James K. Dodson Company, 2003.)

instability. MPD is known to mitigate pressure control–related problems and has great potential to increase the efficiency of drilling operation. A similar result is reported by Hannegan (2007) in the Asia Pacific region.

In addition to improving the drilling operation, MPD has the potential to introduce economic value. As an average in the Gulf of Mexico, NPT increases drilling cost between \$70 and \$100 per foot. Economic analysis of the data in Figure 1.1 and costs related to MPD implementation indicate that MPD may decrease drilling cost by \$25 to \$40 per foot.

Statistics and economic analysis indicate that applying MPD to the current drilling practices can reduce NPT and improve the economy. The economic advantages of MPD has driven companies to consider this technology and drilling costs.

1.3.1 An Adaptive Process

A successful project requires careful planning and attention to the operating details. However, when a problem occurs, planning should be flexible enough to remedy the situation. As mentioned in the definition, MPD is an “adaptive drilling process.” Although it is the main advantage of MPD, the word *adaptive* is the key. MPD prepares the operation to change to meet pressure profile objectives while drilling.

1.3.2 Extending the Casing Points

Casing is the solution to most well-bore problems. However, until the advent of expandable casing, each casing string reduced the hole size. The offshore industry ended up in the absurd, expensive situation of starting with a 36-in. (914-mm) diameter hole to drill a 6-in. (152-mm) hole into a reservoir. MPD techniques deal with methods of extending the casing point beyond the normal pore pressure or fracture gradient limit to reduce the number of casing strings required. Figure 1.2 illustrates how MPD can eliminate casing strings. Conventional drilling requires seven casing strings while MPD reaches the target with three casing strings (Figure 1.3).

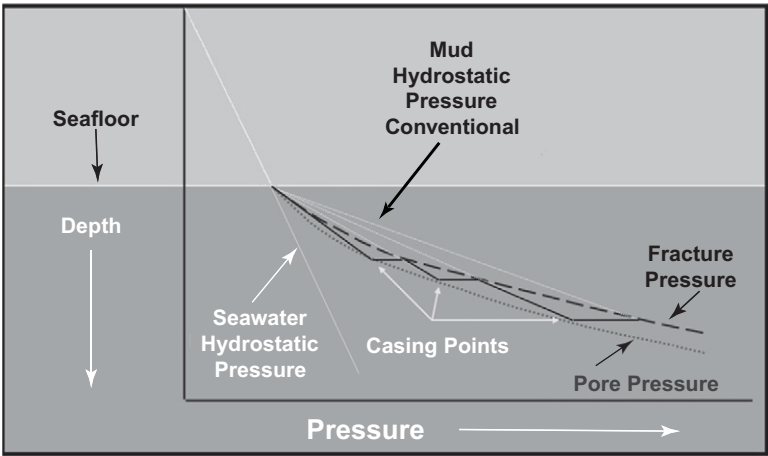


Figure 1.2 Conventional drilling provides a narrow drilling window in offshore fields because of the extra hydrostatic pressure of mud in the riser.

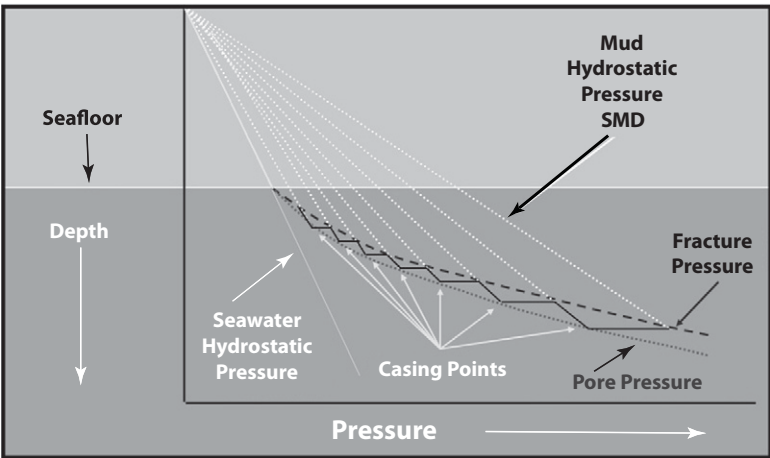


Figure 1.3 MPD techniques allow drillers to eliminate or reduce the extra pressure of mud in the riser, resulting in a wider drilling window; SMD is subsea mud-lift drilling.

MPD controls the pressure profile in the annulus to avoid drilling problems. Drilling deeper and eliminating casing strings allows the target to be reached with a larger hole for completion and production. It reduces the cost of the operation and adds economic value to the project.

New efforts in expandable casing and drilling with casing are modifying the hole reduction problem. The prospect of a single hole size from surface to TD (monoboires) is a matter of cost, technical improvement, and experience.

1.3.3 Lost Circulation

Lost circulation is one of the major causes of NPT. It occurs when the mud density is increased to the point where the formation fracture pressure is exceeded. All drilling engineers are trained to control pressures down the hole. Their training, response, and natural tendency are to increase mud density to avoid well kicks and trip gas. In MPD, maintaining the mud density below the fracture pressure and using a variable annular back pressure at the surface enable the operator to maintain the well-bore pressure between the pore pressure and fracture pressure. Therefore, lost circulation and well kicks are avoided.

1.3.4 Well Kicks

Even in the best of all worlds, where a well kick is detected at the opportune time, circulated out of the hole, and the drilling fluid density increased with no difficulty, there are additional costs for time and mud materials. In addition, the potential for differential sticking of the drill pipe, lost circulation, and the overall cost of well kicks can be a large part of the drilling budget. MPD seeks to avoid the problem of well kicks by carefully monitoring the ECD in the hole and controlling inflow and outflow or pressure changes in the well bore with impressed surface pressure. Under carefully controlled conditions, an incipient well kick caused by ECD change or a transition zone is almost an indistinguishable bump in drilling conditions.

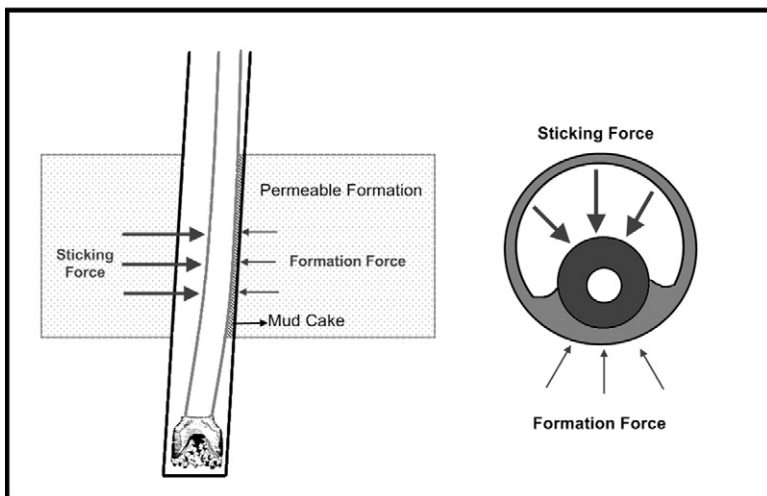


Figure 1.4 In front of permeable zones, a mud cake causes differential pressure between the well bore and the formation, which in turn causes differential sticking.

1.3.5 Differentially Stuck Drill Pipe

Stuck pipe is a major cost issue in some drilling provinces, as evidenced by the large volume of literature and number of computer programs dedicated to the problem. Often a well kick initiates or is the result of the pipe sticking. Differential sticking is caused by the difference in pressure between the well bore and a permeable zone. Here, the mud filter cake retards the flow of liquid into the lower-pressure permeable zone and the pipe is differentially stuck against the wall (Figure 1.4). Keeping a lower differential pressure between the well bore and the formation reduces sticking tendencies.

1.3.6 Deepwater Drilling

Deepwater drilling with shallow-water flows and lost circulation is a major challenge that becomes more critical as the water depth increases. Dual-density drilling has evolved a solution to this problem.

In deepwater drilling, the fracture pressure of the soft sediment on the seafloor is roughly equal to overburden pressure (the pressure of the seawater column plus the pressure of the sediment). Within the sediment, sand containing water zones is pressured to near overburden pressure (Figure 1.5). The long column of drilling fluid in the riser can be given the density to control water flows just below the casing shoe, but as the open hole is deepened, any increase in drilling fluid density required to control the deeper and more-pressured water flow will cause lost circulation at the shoe or drive pipe.

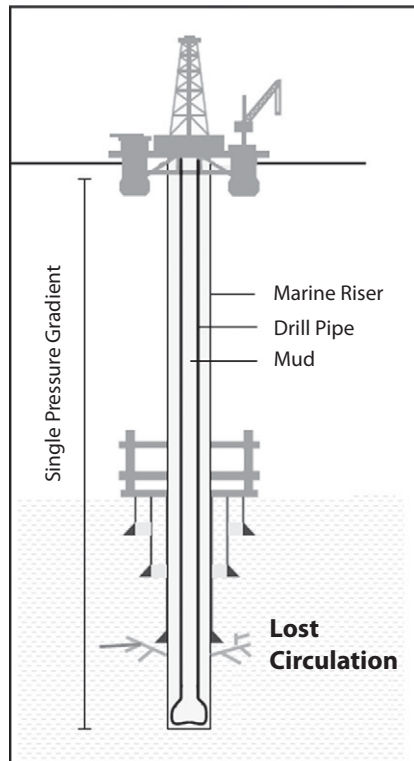


Figure 1.5 The narrow margin between the pore pressure and fracture pressure in deepwater drilling causes frequent loss and gain in the operation.

One solution to this problem is “pump and dump.” A drilling fluid heavy enough to hold back any water flows is pumped down the drill pipe and up the annulus to the seafloor, where it is dumped. This process has potential environmental problems.

A “riserless system” pumps the heavier drilling fluid down the drill pipe but recovers it at the subsea wellhead and, with a subsea pump, returns it through an umbilical line connected to the drilling vessel. The subsea pump supports the column of mud to the surface. This solves the problem of increased pressure from a long column of heavy drilling fluid in the annulus. A “dual-density” system uses a subsea pump to return drilling fluid to the surface and various techniques to change the density of the drilling fluid in the annulus.

1.4 Basic Mathematical Ideas behind MPD

Some of the basic managed pressure drilling principles are referenced to further the understanding of the basics of MPD operations. This section should not be construed as the final, precise solution to some rather complicated models, but it does contain the basic information necessary to understand the problems of MPD.

1.4.1 Bottom-Hole Pressure Calculations with Liquids

The simple terms used to determine bottom-hole pressure in a well bore filled with a drilling fluid are reasonably correct as long as the margin of error is acceptable:

$$\text{BHP} = D \times \rho \times C \quad (1.1)$$

where

BHP = bottom-hole pressure

D = depth

ρ = density

C = units conversion factor

(or, in the English system, $\text{BHP} = D \times \text{MWD} \times 0.052$).

Considering the thermal expansion in both water-based and oil-based mud can lead to

- A lower bottom-hole pressure than is calculated by the simple BHP expression, especially in oil or invert emulsion drilling fluid.
- Compression of the oil in a heavy oil-base drilling fluid, which can override the expansion effects of high temperature and increase bottom-hole pressure.

Hydrostatic pressure calculation in deep wells, with high bottom-hole pressure and temperature, requires a correction for the fluid density of each interval of the hole. Increasing temperature decreases the density of fluid, while increasing pressure increases fluid density (Figure 1.6). The effect of pressure is especially significant in synthetic and oil-based mud.

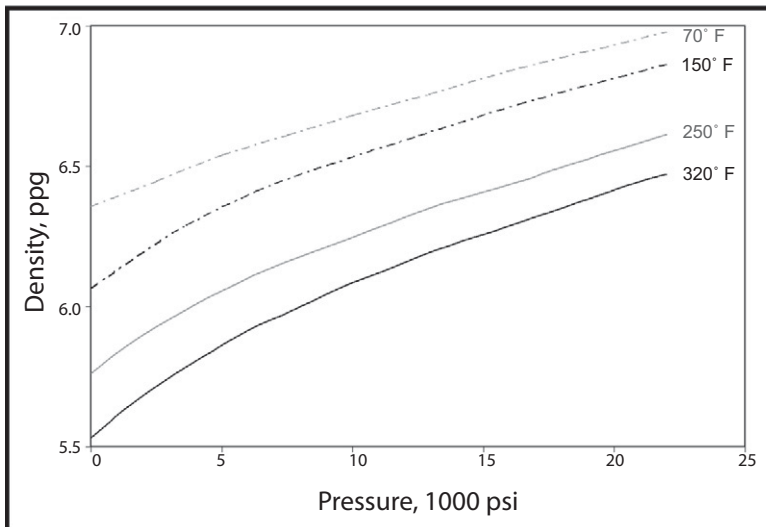


Figure 1.6 The density of drilling fluids, especially oil-based fluids, changes with pressure and temperature. In high-pressure/high-temperature wells, the density change may be significant. (Courtesy of Mullen et al., 2001.)

1.4.2 Expansion (or Compression) of a Gas Bubble with No Fluid Flow

The general gas law shows that the volume of a gas bubble will expand by 100% every time the absolute pressure is reduced by 50% (subject to correction for the absolute temperature and the Z factor).

1.4.3 Ideal Gas Law

When a gas bubble under pressure displaces up the hole, such as with gas cutting, trip, or connection gas, the pressure/volume relationship has to take into effect the reduction in pressure due to gas above the bubble of interest. The Strong-White expression for gas cutting proposed in 1962 is an iterative solution to the pressure reduction and gas expansion. For an ideal gas,

$$PV = nRT \quad (1.2)$$

where

P = pressure

V = volume

n = amount of gas, mole

R = gas constant

T = absolute temperature

If pressure is in psi, volume in ft³, and T in Rankins, the value of R is 10.73.

The ideal gas law can be rearranged as

$$\frac{PV}{T} = nR = C \quad (1.3)$$

If the amount of gas is constant (C), changing the gas pressure, volume, or temperature does not change the value of C . Therefore, if two parameters change from initial condition, the third parameter can be calculated by

$$\frac{P_1 V_1}{T_1} = \frac{P_2 V_2}{T_2} \quad (1.4)$$

For conditions where the gas deviates from the ideal gas law, parameter Z is introduced into the equation and is called Z factor. The Z factor is a function of gas composition, pressure, and temperature. The value of Z can be estimated using pseudo-reduced chart or correlations. Introducing Z factor to the ideal gas law causes the following changes:

$$PV = nZRT \quad (1.5)$$

$$\frac{P_1 V_1}{Z_1 T_1} = \frac{P_2 V_2}{Z_2 T_2} \quad (1.6)$$

1.4.4 Strong-White Equation

Strong proposed an equation to calculate bottom-hole pressure reduction because of a gas cut of drilling fluid. In the original equation, the pressure is expressed in atmospheres. The original equation is

$$b = \frac{1}{G_p} \left\{ P_{\text{atm}} + \frac{n}{100} \times p_{\text{atm}} \times \ln \left[\frac{P_{\text{atm}} + p_{\text{atm}} \left(1 - \frac{n}{100} \right)}{p_{\text{atm}} \left(1 - \frac{n}{100} \right)} \right] \right\} \quad (1.7)$$

where

b = depth, ft

G_p = hydrostatic pressure gradient, atm/ft

P_{atm} = hydrostatic pressure at the bottom of the hole, atm

p_{atm} = back pressure at the surface, atm

$n/100$ = volume fraction of gas in the mud at the surface

If the wellhead is open to the atmosphere, the equation reduces to

$$bG_p - P_{\text{atm}} = \frac{n}{100 - n} \times \ln(P_{\text{atm}} + 1) \quad (1.8)$$

where $(bG_p - P_{\text{atm}})$ is the amount of pressure reduction at the bottom of the hole caused by a gas cut. A trial-and-error method is required to solve the equation for P_{atm} . This equation is derived for

a low percentage of a gas cut of drilling fluid. However, this equation does not consider a volumetric change of gas in the well bore properly. The accuracy of the original model is very close to modified models at low gas volume. At a high percentage of gas volume, this model is not stable and provides erroneous results.

Example 1.1

Find (1) the bottom-hole pressure reduction and (2) the equivalent mud weight (EMW) reduction.

Depth = 14,000 ft.

Mud weight = 17.0 pounds per gallon.

Gas cut = 50%.

Solution to Example 1.1

$$G_p = \frac{17 \times 7.48}{144 \times 14.7}$$

$$G_p = 0.0601 \text{ atm/ft}$$

$$bG_p = 841 \text{ atm}$$

$$n = 50$$

$$841 - P_{\text{atm}} = \frac{50}{100 - 50} \ln(P_{\text{atm}} + 1)$$

Applying the trial-and-error method, estimated P_{atm} is 834.3 atm (12,260 psi) and the bottom-hole pressure reduction ($bG_p - P_{\text{atm}}$) is 6.7 atm or 99 psi. The equivalent mud weight reduction is less than 0.14 ppg.

A simplistic model of the Strong-White equation in oilfield terms, after Haston (1975), is

$$\Delta P_{\text{atm}} = n \times 2.3 \times \log(p_{\text{atm}}) \quad (1.9)$$

where

ΔP_{atm} = reduction in bottom-hole pressure, atm

n = ratio of gas to mud

p_{atm} = hydrostatic pressure, atm

$$n = (1 - x)/x$$

x = weight of cut mud/weight of uncut mud

Equation 1.9 is rearranged in oilfield terms:

$$\Delta P_{\text{atm}} = \left(\frac{W_1 - W_2}{W_2} \right) \times 33.81 \times \log \left(\frac{p_{\text{atm}}}{14.7} \right) \quad (1.10)$$

where

ΔP_{atm} = bottom-hole pressure reduction, psi

W_1 = weight of uncut mud, pounds per gallon (ppg)

W_2 = weight of cut mud, in ppg

p_{atm} = hydrostatic pressure of mud, atm

Example 1.2

Depth = 14,000 ft.

Cut mud = 8.0 ppg.

Mud weight = 17.5 ppg.

Find (1) the bottom-hole pressure reduction and (2) the EMW reduction.

Solution to Example 1.2

$$\Delta P_{\text{atm}} = 33.81 \times \frac{17.5 - 8}{8} \times \log \frac{14,000 \times 17.5 \times 0.052}{14.7} = 118 \text{ psi}$$

$$\text{Mud weight reduction} = \frac{118}{14,000 \times 0.052} = 0.16 \text{ ppg}$$

where 0.052 = units conversion, psi/ft/ppg; 1 ppg mud exerts 0.052 psi pressure per foot.

1.4.5 The Effect of Annular Pressure Loss on Bubble Size

Annular pressure loss (APL) affects bubble expansion because of increased pressure. The result is that the Strong-White expression for bottom-hole pressure reduction, because of bubble expansion

and rise during circulation, gives an answer that is too great. Without going into the complex solutions for APL, surface impressed pressures, and bubble volumes, it is evident that gas cutting measured at the shale shaker during MPD operations has little relation to or effect on the bottom-hole pressure. For those interested, the most applicable solutions are found in gaseated mud programs that combine bubble expansion and flow rate in the bottom-hole pressure calculation.

1.5 Basic Well Control

Almost all MPD operations involve circulating a well as a closed system with a constant pump rate and choke control. The MPD techniques tie back to some of the basic well-control procedures with some modifications.

The field engineer or operator needs to be aware that well-control ideas apply directly to a very specific condition of no lost returns and a minimal amount of gas spread out through the mud column (and no gas in the drill pipe). Nevertheless, much of MPD makes a great deal more sense if the operator is familiar with well-control techniques.

If there are any questions about the following short description of well control, it would be advantageous to review well-control principles because there are distinct relationships between well control and MPD.

The following steps are for the “driller’s method” of well control, which closely resembles MPD operations. The second set of steps is for the “wait and weight method” of well control.

1.5.1 Driller’s Method of Well Control

1. Shut in the well on a kick.
2. Read the shut-in drill-pipe pressure, annulus pressure, and kick size (pit volume increase).
3. Start circulating using the predetermined slow-rate circulating pressure (SRP) plus the shut-in drill-pipe pressure, or hold the

- annulus pressure constant until the pump rate is up to the planned slow rate, then hold the drill-pipe pressure constant.
4. Continue circulating keeping the pump rate constant.
 5. Circulate until the kick is out of the hole.
 6. Calculate from Section 1.5.3:
 - a. The mud density increase.
 - b. The time required for the mud to fill the drill pipe (surface-to-bit time).
 7. Start pumping at the required rate and hold the annulus pressure constant until the new, heavier mud fills the drill pipe.
 8. Then, hold the drill-pipe pressure constant until the well is clean and shut-in drill-pipe pressure (SIDPP) and shut-in casing pressure (SICP) are zero.

1.5.2 Wait and Weight Method of Well Control

1. Check the pump pressure at half the normal drilling rate and record the pressure as the SRP at this pump rate.
2. When a kick occurs, shut in the well.
3. Record the SIDPP, SICP, and the pit volume increase (kick size).
4. Calculate from Section 1.5.3:
 - a. The new mud weight (W_2).
 - b. The initial circulating pressure (ICP).
 - c. The circulating time down the drill pipe (Tdp).
 - d. The final circulating pressure (FCP).
 - e. The plot and graphical value for drill-pipe pressure drop.
 - f. The total kill time (TK).
5. Increase the mud density in the pits enough to kill the kick.
6. Start circulating at the slow rate and control the standpipe pressure at the ICP.

7. Follow the values for drill-pipe pressure drop.
8. Then circulate the well clean using the FCP.

1.5.3 Basic Well-Control Formulas

$$W_2 = W_1 + \frac{\text{SIDPP}}{0.052 \times \text{TVD}} \quad (1.11)$$

$$\text{ICP} = \text{SIDPP} + \text{SRP} \quad (1.12)$$

$$\text{FCP} = \text{SRP} \times \frac{W_2}{W_1} \quad (1.13)$$

where

W_1 = initial mud weight or density

W_2 = final mud weight or the mud weight required to kill the well

SIDPP = shut-in drill-pipe pressure

TVD = vertical depth

ICP = initial circulating pressure

SRP = slow-rate circulating pressure

FCP = final circulating pressure

New circulating pressure at a different pump rate can be estimated as

$$\text{New pressure} = \text{Old pressure} \times \left(\frac{\text{New pump rate}}{\text{Old pump rate}} \right)^2 \quad (1.14)$$

$$\text{Pumping time} = \frac{\text{Volume}}{\text{Pump factor} \times \text{Pump rate}} \quad (1.15)$$

$$\text{Surface-to-bit time} = \frac{\text{Drill string volume}}{\text{Pump factor} \times \text{Pump rate}} \quad (1.16)$$

$$\text{Length of influx} = \frac{\text{Pit gain}}{\text{Annular capacity}} \quad (1.17)$$

Expected pit gain and surface pressure when the gas is at the surface can be estimated as follows:

$$\text{Pit gain} = 4 \times \sqrt{\frac{\text{Formation pressure} \times \text{Initial pit gain} \times \text{Annular capacity at the surface}}{W_2}} \quad (1.18)$$

$$\text{Maximum surface pressure} = 0.2 \times \sqrt{\frac{\text{Formation pressure} \times \text{Initial pit gain} \times W_2}{\text{Annular capacity at the surface}}} \quad (1.19)$$

1.5.4 Lag Time—Choke to Bottom of the Hole or Choke to Standpipe

In well-control operations, lag time for a choke operation is estimated to be 1000 ft/min of total distance. This is a reasonably accurate time lag for MPD choke operations.

If any significant amount of gas is in the hole, as with large well kicks, gaseated mud, or foam, the lag time becomes the sum of velocity in a mixed system under various pressures plus compression or decompression time. In MPD operations, gas volume in the annulus normally is minimal.

Pressure propagation in fluid is analogous to sound velocity in that medium. The time required for the pressure pulse to travel from the choke to a desired target is called the *pressure transient lag time*. Usually, the desired target is either the bottom of the hole or the standpipe. Since applying back pressure does not pressurize the well instantaneously, the pressure adjustment is confirmed by the pressure change at the standpipe. In MPD well operations, the pressure change at the choke travels in the well at the speed of about 1000 ft/min. Choke handling at the surface changes the pressure profile in the well with a constant value; therefore, it causes equal pressure variation at the surface, bottom of the hole, and standpipe.

1.6 Pore Pressure

Pore pressure (the pressure of the fluid in the pore spaces) increases from zero at the surface at a rate that is equal to a column of water

extending from the point of interest to the surface, or at about 0.43 psi/ft (9.37 Pa/m) in fresh-water basins and 0.47 psi/ft (10.63 kPa/m) in saline or marine environments. These are considered the “normal” pressure gradients:

$$\text{Pore pressure} = \text{Formation water gradient} \times \text{TVD} \quad (1.20)$$

However, the straight-line increase may be offset because of transition zones, faults, or geologic discontinuities; and this leads to problems in avoiding well kicks and setting casing depths.

So, in a simplistic sense,

$$\begin{aligned} \text{Pore pressure} = & \text{Formation water gradient} \times \text{TVD} \\ & \times \text{Lateral stress} \end{aligned} \quad (1.21)$$

Subnormal pressured formations have pressure gradients less than normally pressured formations. Subnormal pressures can either occur naturally in formations that have undergone a pressure regression because of deeper burial from tectonic movement or, more often, as a result of depletion of a formation because of production of the formation fluids in an old field.

Abnormally pressured formations have pressure gradients greater than normally pressured formations. In such formations, the fluids in the pore spaces are pressurized and exert pressure greater than the pressure gradient of the contained formation fluid.

Many abnormally pressured formations are created during the compaction of the impermeable water-filled sediments or adjacent shales (diagenesis). When a massive shale formation is completely sealed, squeezing of the formation fluids causes the fluid in the pore space to pick up some of the overburden pressure.

Abnormally pressured formations may form in other ways and may be found in the presence of faults, salt domes, or geologic discontinuities. The transition zone to a higher-pressure gradient may vary from a few feet to thousands of feet.

Models and correlations are developed to estimate pore pressure. Usually, log data and seismic data are used to estimate pore pressure and detect zones with different pore pressure gradients. Eaton (1997) proposed a correlation using log data to predict pore pressure in

abnormally pressured zones. Using log data, he developed a normal trend of change on sonic velocity log and resistivity. Deviation from this line defines abnormal zones, and the magnitude of deviation is correlated to pore pressure. In general, Eaton's method is written as

$$\text{Pore pressure} = P_{\text{Overburden}} - (P_{\text{Overburden}} - P_{\text{Normal}}) \left(\frac{\text{Log value}}{\text{Value of normal trend}} \right)^K \quad (1.22)$$

where K is an empirical value and depends on the field and type of log being applied. In the Gulf of Mexico, the value of K for a sonic log is 3 and is 1.2 for resistivity log.

1.7 Overburden Pressure

The pressure exerted by the weight of the rocks and contained fluids above the zone of interest is called the *overburden pressure*. The overburden pressure varies in different regions and formations. The common range of rock overburden pressure, in equivalent density, varies between 18 and 22 ppg (2.17–2.64 SG). This range would create an overburden pressure gradient of about 1 psi/ft (22.7 kPa/m). (The 1 psi/ft is not applicable for shallow marine sediments or massive salt.) The overburden pressure is not a fluid-dependent pressure. Hence, it would be more applicable to utilize the rock matrix bulk density to express the mathematical formula, as follows:

$$S = \rho_b \times D \quad (1.23)$$

where

S = overburden pressure

ρ_b = average formation bulk density

D = vertical thickness of the overlying sediments

The bulk density of the sediment is a function of rock matrix density, porosity within the confines of the pore spaces, and pore-fluid density. This can be expressed as

$$\rho_b = \phi \rho_f + (1 - \phi) \rho_m \quad (1.24)$$

where

ϕ = rock porosity

ρ_f = formation fluid density

ρ_m = rock matrix density

According to Eq. 1.24, there is a proportional relationship between burial depth and the overburden pressure. For instance, clays show a weight-dependent relationship in which representing porosity and depth on an arithmetical scale would yield to an exponential function. However, a logarithmic expression of porosity would lead to a linear porosity/depth relationship. In most cases, the relationship is not just simple compaction from burial depth; and many parameters, such as pore-fluid composition, diagenetic effects, and sediment sorting, affect the complexity of the case.

1.8 Rock Mechanics

Many parameters lead to the creation of abnormal, normal, or sub-normal formation pressure. Analyzing each parameter is pertinent for engineering problem solving. Prediction or estimation of some of these parameters, such as overburden pressure, pore pressure, and fracture pressure, are critical to any engineering and production operations. See Appendix A (A.1 “Stress and Strain”) for background definitions.

1.8.1 Fracture Pressure

The amount of pressure a formation can withstand before it fails or splits is known as the *fracture pressure*. It can be also defined as the pressure at which the formation fractures and the circulating fluid is lost. Fracture pressure is usually expressed as a gradient, with the common units being psi/ft (kg/m) or ppg (kPa). Deep formations can be highly compacted because of the high overburden pressures and have high fracture gradients. In shallow offshore fields, because of the lower overburden pressure resulting from the seawater gradient, lower fracture gradients are encountered. Many of the formations drilled offshore are young and not as compacted as those onshore, which results in a weaker rock matrix.

Estimation of the fracture pressure involves estimating the minimum component of the in-situ stresses. At shallow depths, the overburden pressure is the lowest principal stress. That yields a horizontal-shaped fracture. At depth, because of the higher overburden pressure, one of the horizontal stresses is recognized as the lowest and a vertical fracture forms. In general, the fracture propagates perpendicular to the minimum in-situ horizontal stress.

Based on the stress concepts, the formation's effective stress is known to be in control of the rock deformation and fracture. The relationship is defined as the difference between pore pressure and total stress:

$$\sigma = S - P_p \quad (1.25)$$

where

σ = effective stress

S = total stress

P_p = pore pressure

Poroelectricity in the near-well-bore condition explains how the pore pressure affects the acting stresses and strains in grain-to-grain rock contact. The concept of effective stress was introduced by Terzaghi, then modified by Biot. The effect of pore pressure in the acting stresses and strains is measured by the Biot constant:

$$\sigma'_{ij} = \sigma_{ij} - \alpha p_p \quad (1.26)$$

and,

$$\alpha = 1 - \frac{C_r}{C_b} \quad (1.27)$$

where

σ'_{ij} = effective stress

σ_{ij} = total stress

α = the Biot constant

p_p = pore pressure

C_r = rock matrix compressibility

C_b = bulk compressibility

Based on theoretical and experimental examination of the mechanics of the hydraulic fracturing, Hubbert and Willis (1957) stated that the total stress is equal to the sum of the formation pressure and the effective stress. They suggested that, in some regions, the absence of tangential forces make the vertical stress equal to the overburden pressure. The horizontal stress then is the weaker stress and most likely lies between one-half and one-third of the effective overburden pressure. The fracture pressure then is defined by formula as

$$P_f = \frac{1}{3}(S - P_p) + P_p \quad (1.28)$$

The fracture pressures calculated by this equation are very conservative and limited to a specific region. Considering that, even in normally pressured formations, formation fracture gradients increase with depth, so the equation is not valid for the deeper formation. Mathews and Kelly (1967) replaced the assumption that the minimum matrix stress was one-third of the overburden and introduced a variable effective stress coefficient as

$$P_f = K_i \sigma + P_p \quad (1.29)$$

where

$$K_i = \frac{\sigma_h}{\sigma_v} = \text{Effective stress coefficient}$$

σ_h = horizontal stress

σ_v = vertical stress

Their method was based heavily on empirical data and the K_i values were dependent on the depth of formation and geological settings. Pennebaker (1968) used the actual depth of the formation and developed a similar correlation regardless of pore pressure.

Eaton (1997) stated that rock deformation is elastic and replaced the effective stress coefficient with Poisson's ratio. Considering that Poisson's ratio and the overburden gradient vary with depth, Poisson's ratio values are determined on the basis of actual regional data for the fracture gradient, the formation pressure gradient, and the

overburden gradient. Based on Eaton's work, the fracture pressure can be shown as

$$P_f = \left(\frac{\nu}{1 - \nu} \right) \sigma + P_p \quad (1.30)$$

where ν = Poisson's ratio.

Eaton and Eaton (1997) proposed the following equations to predict Poisson's ratio in the Gulf of Mexico. For the Gulf Coast of the Gulf of Mexico for TVD, from the seabed to 4999 ft below mean sea level (BML), Poisson's ratio is estimated as

$$\nu = -7.5 \times 10^{-9} \text{ Depth}^2 + 8.0214286 \times 10^{-5} \text{ Depth} + 0.2007142857 \quad (1.31)$$

In the Gulf Coast for TVD deeper than 5000 ft BML, Poisson's ratio is estimated as

$$\nu = -1.72258 \times 10^{-10} \text{ Depth}^2 + 9.4748424 \times 10^{-6} \text{ Depth} + 0.3724340861 \quad (1.32)$$

For the deep water of the Gulf of Mexico, from the seabed to 4999 ft BML, Poisson's ratio is estimated as

$$\nu = -6.089286 \times 10^{-9} \text{ Depth}^2 + 5.7875 \times 10^{-5} \text{ Depth} + 0.3124642857 \quad (1.33)$$

In the deepwater area of the Gulf of Mexico for TVD deeper than 5000 ft BML,

$$\nu = -1.882 \times 10^{-10} \text{ Depth}^2 + 7.2947129 \times 10^{-6} \text{ Depth} + 0.4260341387 \quad (1.34)$$

The variation of fracture gradients from one place to another at identical depth in similar formations were attributed to the shale content of the formations by Anderson, Ingram, and Zanier (1973). Using that, on the basis of Biot's formulation, the relationship between the shale content and Poisson's ratio was established.

Cesaroni et al. (1986) presented a method that emphasized the mechanical behavior of rocks with respect to the fracture gradient.

In their method, three possible cases were suggested as follows. First, low permeability or rapid mud-cake buildup with little or no filtrate:

$$P_f = \frac{2v}{1-v} \sigma + P_p \quad (1.35)$$

Second, elastic formations with a deep mud-invasion profile:

$$P_f = 2\sigma v + P_p \quad (1.36)$$

Third, plastic formations:

$$P_f = S \quad (1.37)$$

Example 1.3

Given the following data on a Texas Gulf Coast well:

Formation pore pressure, $P_p = 0.735$ psi/ft.

Overburden stress, $S = 1$ psi/ft.

Depth = 12,000 ft.

Using the methods mentioned earlier, calculate the fracture gradient.

Solution to Example 1.3

According to Hubbert and Willis (1957),

$$P_f = \frac{1}{3} (S - P_p) + P_p$$

$$P_f = \frac{1}{3} (1 - 0.735) + 0.735 = 0.823 \text{ psi/ft}$$

According to Mathews and Kelly (1967), first, we calculate the effective stress gradient as

$$\sigma = S - P_p$$

$$\sigma = 1 - 0.735$$

$$\sigma = 0.265 \text{ psi/ft}$$

and the effective stress at the depth of 12,000 ft is

$$\sigma = 0.265 \times 12,000 = 3180 \text{ psi}$$

To determine the effective stress coefficient, K_p , first, we need to calculate the depth, D_p , where under normally pressured conditions, the rock effective stress would be 3180 psi:

$$S_n = \sigma_n + P_n$$

$$1 \times D_i = 0.465 \times D_i + 3180$$

$$D_i = 5944 \text{ ft}$$

Now, using the graph in Figure 1.7, K_i is calculated to be 0.62.

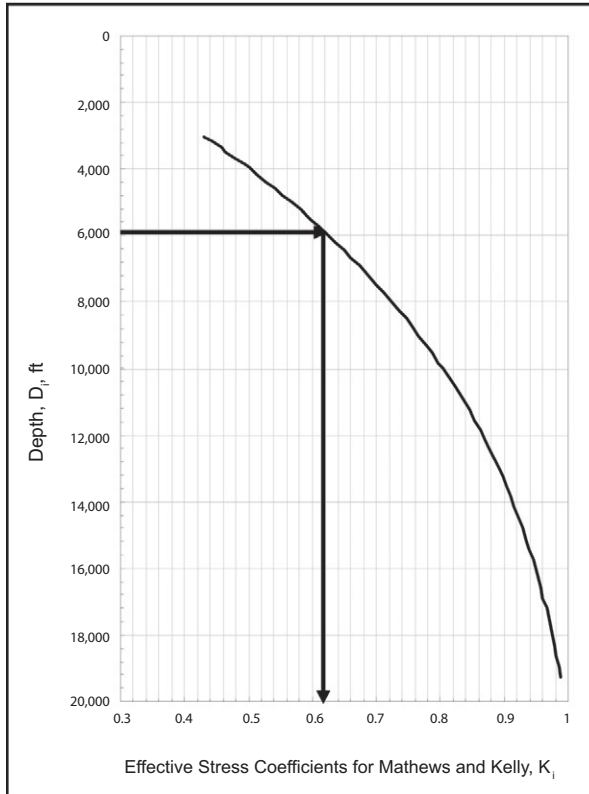


Figure 1.7 The Mathews and Kelly method estimates horizontal stress as a function of depth. (Courtesy of Mathews and Kelly, 1967.)

Knowing the value of K_f , the formation fracture gradient is calculated as

$$P_f = K_f \sigma + P_p$$
$$P_f = 0.62 \times 0.265 + 0.735$$
$$P_f = 0.899 \text{ psi/ft}$$

Finally, Poisson's ratio from the graph, based on the Gulf Coast variable overburden pressure, developed for the Eaton's correlation, is calculated to be 0.47. Instead of assuming the constant overburden gradient of 1 psi/ft, using Figure 1.8, the variable overburden

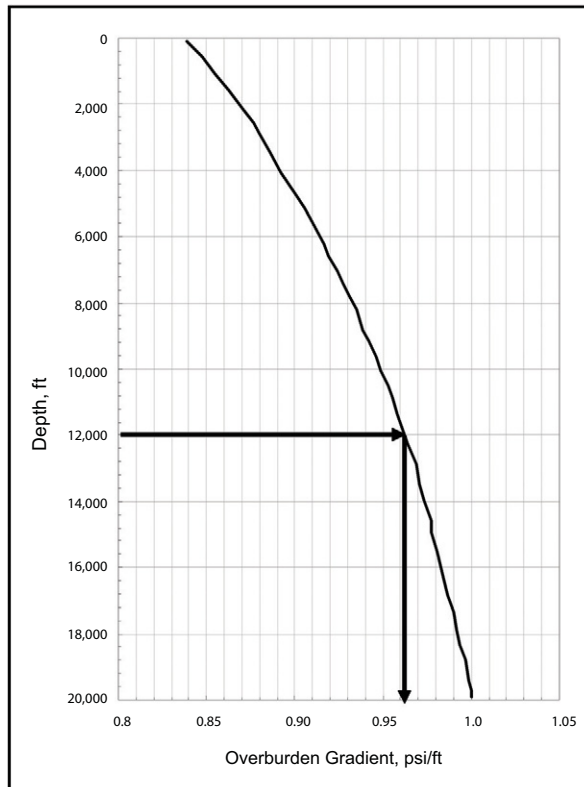


Figure 1.8 General overburden stress gradient for normally compacted formations in the Gulf of Mexico. (Courtesy of Eaton, 1997.)

gradient for the Gulf Coast is determined to be 0.96 psi/ft. Hence, the effective stress gradient is calculated as

$$\begin{aligned}\sigma &= S - P_p \\ \sigma &= 0.96 - 0.735 \\ \sigma &= 0.265 \text{ psi/ft}\end{aligned}$$

Using Poisson's ratio of 0.47 and the overburden gradient of 0.265 psi/ft, the formation's fracture gradient is calculated as

$$\begin{aligned}P_f &= \left(\frac{\nu}{1 - \nu} \right) \sigma + P_p \\ P_f &= \left(\frac{0.47}{1 - 0.47} \right) \times 0.265 + 0.735 = 0.934 \text{ psi/ft}\end{aligned}$$

1.8.2 Well-Bore Ballooning and the Leak-Off Test

The *leak-off* can be defined as the magnitude of pressure exerted on a formation that forces the fluid into the formation. The fluid might flow into the pore spaces of the rock or into cracks opened and propagated into the formation by the fluid pressure. In MPD, note the relationship of leak-off to well-bore ballooning. In a typical MPD operation, the well-bore pressure is near the fracture pressure. It is especially evident in elastic marine sediments that the formation takes fluid into induced fractures under pressure and gives up the fluid when the pressure is released. In elastic rock, the leak-off pressure is not a hard fracture initiation or breakdown pressure but rather a zone of pressure increase.

The leak-off test (LOT) is performed to determine the strength or fracture pressure of the open formation. The test is usually conducted immediately after drilling below a new casing shoe. During the test, the well is closed and fluid is gradually pumped into the well bore. As the well-bore pressure increases, at a certain pressure, fluid enters the formation, either moving through permeable paths in the rock or creating a space by fracturing the rock.

During the LOT, injected volume is plotted versus surface pressure, in real time. The initial stable portion of this plot for most cases is a straight line. The leak-off is the point of permanent de-

flection from that straight portion. The result of the LOT controls the maximum pressure or mud weight that can be applied to the well during drilling operations. Interpretation of the LOT could be considered as the basis for the critical decisions, such as casing setting depths, mud weights, cement job evaluations, and well-control alternatives. For safety reasons, the maximum operating pressure is to be slightly below the leak-off pressure. Knowing the leak-off pressure, the well designer must either adjust plans for the well or, if the design is sufficiently safe, proceed as planned. Also, the LOT can be conducted to provide measurements for engineers to determine the feasibility of the mud increase during a drilling program.

In a LOT, the pressure at which the exposed formation would fracture or begin to take whole mud is known as the *leak-off pressure*. Unlike the LOT, during a formation integrity test (FIT), the formation is pressurized to a predetermined pressure, which is usually less than the leak-off pressure. Each test has its place, and the decision to fracture the rock depends on factors such as perceived risk, knowledge of the area, and certain aspects of the well-bore program.

The procedures for the LOT and FIT, shown in Figures 1.9 and 1.10, are similar in concept. To perform a LOT test, from the last

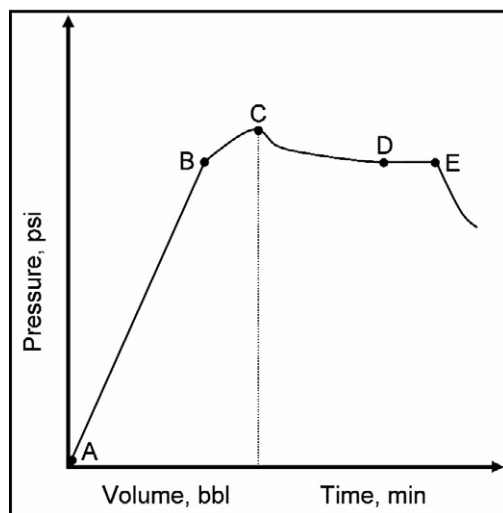


Figure 1.9 The typical pattern of a leak-off test.

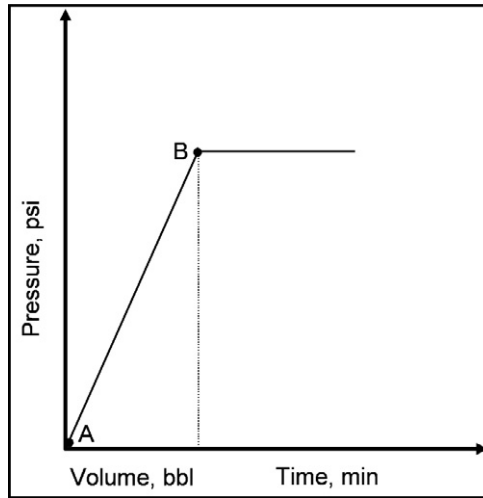


Figure 1.10 The typical formation integrity test.

casing shoe, approximately 10 ft of the formation must be drilled. Then, the well is circulated clean. The bit is pulled back into the casing. The rams are closed and a slow pump rate commences the actual test. The pump rate should be as slow as possible yet high enough to overcome any filtration rate of the fluid.

A typical leak-off test can be described as follows:

- Point A to Point B: The annular pressure is increased linearly with respect to the pumped volume. The linearity corresponds to the elastic behavior of the formation.
- Point B, known as the *LOT point*: The yield point is reached and fluid starts to leak off into the formation.
- Point B to Point C: Because of the penetration of mud into the formation, the increase in pressure per pumped volume is reduced.
- Point C, known as *formation breakdown pressure* (FBP): The FBP is an unpredictable value that depends on the tensile strength of the rock, the stress concentration around the well bore, the type of created fracture, and the frictional losses of

the fluid moving through the fractures. When the pump is stopped, two scenarios might occur: Either the pressure stabilizes and plateaus or there is a sudden drop in pressure following well breakdown or reopening of a previously created or natural vertical fracture in the well.

- Point C to Point D, end of fracture propagation: The pressure falls to the stabilized pressure regime, point D, which is less than or equal to the pressure at point B.
- Point E: The well is shut in and the pressure decline is monitored for at least 10 min.

Note: After the excess pressure is bled down, the amount of mud recovered should be equal to the volume pumped during the actual test. If the return is less than the pumped amount, the pressure at point D is lower than the pressure at point B and it is likely that the cracks remain partially open and cuttings or mud filtrate obstructs the openings. The blockage of the cuttings prohibits the fluid from traveling back to the well bore. In this case, the return fluid has less viscosity and a lower density than the drilling fluid.

In a brittle permeable zone, enlargement of the area of contact between mud and the formation may result in major losses of fluids. Hence, the LOT involves the risk of weakening the walls of the well bore, thus reducing the fracture gradient at this region. If sufficient geological data exist, a predetermined maximum value can be assumed to be sufficient in the light of the expected pressures (FIT), so that reaching the formation breakdown pressure can be avoided. Note that the values used during a FIT test cannot be used to evaluate the true fracture gradients of the formation.

Some of the main parameters affecting the LOT data are the plastic behavior of formations, preexisting cracks, faults, cement channels, casing expansion, test equipment and gauges, injection rates, and pump efficiency. Experience has shown some other factors, such as variation in pump rate, the influence of gel strength, air trapped in lines, insufficient contrast between leak-off and the mud weight used, and noise on the pressure gauge, could mask the transition points of a LOT plot and make it more difficult to interpret the data.

Questions

1. What is the single most important result from an MPD operation?
2. What is the complete term for
 - a. MPD.
 - b. CBHP.
 - c. PMCD.
 - d. NPT.
 - e. BHP.
 - f. IADC.
3. What is the basic term (equation) for bottom-hole pressure?
4. In an MPD operation in a 14,000-ft well, a 17.5-ppg mud circulates up a connection gas cut at the shale shaker of 8.7 ppg. What would you estimate the maximum bottom-hole pressure reduction to be due to the gas cut?
5. How could you tell the difference on a connection between well-bore ballooning and the beginning of a well kick?
6. Why would a well stand full of mud but lose circulation when trying to circulate?
7. Apply Eaton's method to predict fracture pressure for a 20,000-ft deep well from the mud line in a water depth of 1000 ft and 9000 ft. Assume a seawater density of 8.55 ppg, the pressure gradient of formation fluid is 0.465 psi/ft, and the average formation density is 18.34 ppg. Give the solution at even 1000-ft intervals.
8. For the leak-off test data in the following table, estimate leak-off pressure. When should the test have stopped?

Injected volume, bbl	Pressure, psi	Injected volume, bbl	Pressure, psi
0	0	2	215
0.25	5	2.25	250
0.5	30	2.5	280
0.75	65	2.75	315
1	88	3	335
1.25	115	3.25	355
1.5	145	3.5	375
1.75	185	3.75	380

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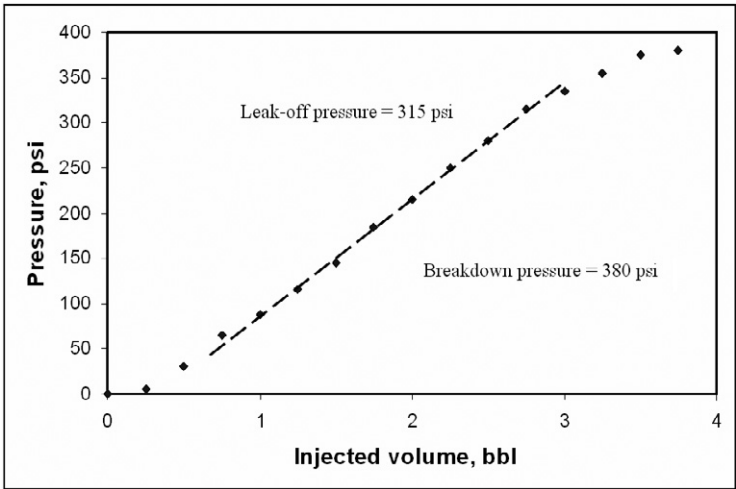
Answers

1. The most important effect of MPD is a safer reduction in NPT. Or, do you have a better short answer?
2.
 - a. MPD is managed pressure drilling.
 - b. CBHP is constant bottom-hole pressure.
 - c. PMCD is pressurized mud-cap drilling.
 - d. NPT is nonproductive time.
 - e. BHP is bottom-hole pressure.
 - f. IADC is the International Association of Drilling Contractors.
3. The basic term for bottom-hole pressure is $BHP = D \times \rho \times C$.
4. For the conditions listed, the reduction in bottom-hole pressure due to gas cutting would be less than 0.15 ppg or 109 psi.
5. There are two practical answers: Previous connections on the rig indicated that ballooning had a certain footprint. Or, if it was a well kick, over time, the flow would increase. If this answer seems less than satisfactory, it is difficult without a "footprint" or experience on the well to tell the difference.
6. Why would a well stand full of mud, but not circulate? Circulation imposes additional pressure on a well, the equivalent circulating pressure or ECD.

7. Applying Eaton’s method to predict fracture pressure for a 20,000-ft deep well from the mud line in a water depth of 1000 ft and 9000 ft. The solution based on 1000-ft intervals is shown in the following table:

Depth, BML	1000 gf, psi/ft	9000 gf, psi/ft
0	0.445	0.445
1	0.554	0.482
2	0.625	0.514
3	0.686	0.546
4	0.732	0.575
5	0.751	0.601
6	0.769	0.623
7	0.785	0.642
8	0.800	0.661
9	0.813	0.678
10	0.825	0.693
11	0.837	0.707
12	0.848	0.721
13	0.858	0.733
14	0.868	0.744
15	0.877	0.754
16	0.885	0.763
17	0.893	0.771
18	0.900	0.779
19	0.906	0.785
20	0.912	0.791

8. For the leak-off test data in the table in Question 7, the leak-off pressure is 315 psi and the breakdown pressure is 380 psi. The stopping point of the test could have been about 335 psi (see the following figure). However, company policy and formation characteristics may modify or define the stopping point.



CHAPTER TWO

Situational Problems in MPD

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About This Chapter

In this book, it is more practical to combine the situational problems by category in a single chapter than spreading them throughout the explanations of the various techniques and procedures, since all the areas share common problems and cautions. ECD or annular pressure drop is covered at length in the second part of this chapter in Section 2.6.

Appendix B deals with the basic principles of rheology, the flow of drilling fluids. For those who have to deal with the problems of flow rates, it is worthwhile to look at the complexity of the problem and realize that oil- and water-based drilling fluids may give very different ECD results.

This book does not deal with an important part of managed pressure drilling: the chemistry of drilling fluid and the problem of gel strength.

Common to presentations of MPD is that the written material is put in neat little logical boxes. Field operation does not necessarily follow the written presentation. In actual operation, problems occur in bunches that cross over all the simple logical solutions.

2.1 Introduction

Basic to MPD planning and execution is the concept that it is an adaptive procedure. Keep in mind the adaptive necessity of operations when following the processes. Practical MPD problems and solutions fall into three general areas:

1. Pore pressure and fracture pressure convergence leave a very small bottom-hole pressure operating window. This is a typical deepwater marine problem, but it is also found in some land operations. Manipulation of the equivalent circulating pressure is the MPD approach to this condition.
2. MPD with pressurized mud caps have proven to be a viable solution to the problem of a total loss of drilling fluid followed by a well kick.
3. Deepwater marine drilling lost circulation occurs when trying to control water and gas flows. Lost circulation is caused by excessive fluid pressure generated by a riser full of drilling fluid. MPD uses dual-gradient fluid columns as a controlled solution to this condition.

The problems listed for each category are major considerations, but they are not unique to that situation. Almost all the technical problems listed occur to some degree in all three categories.

2.2 ECD Manipulation—Pore Pressure and Fracture Pressure Convergence

Managing the well-bore pressure in a small operating window between pore pressure and lost circulation involves manipulating the circulating density while using a minimum mud density (Figure 2.1). The static pressure of mud is very close to formation pore pressure. Pore pressure is not always the lower critical pressure, especially in directional wells. Well-bore stability that is a function of stress and well direction may form the base for the lowest practical mud density as well as modifying the fracture pressure.

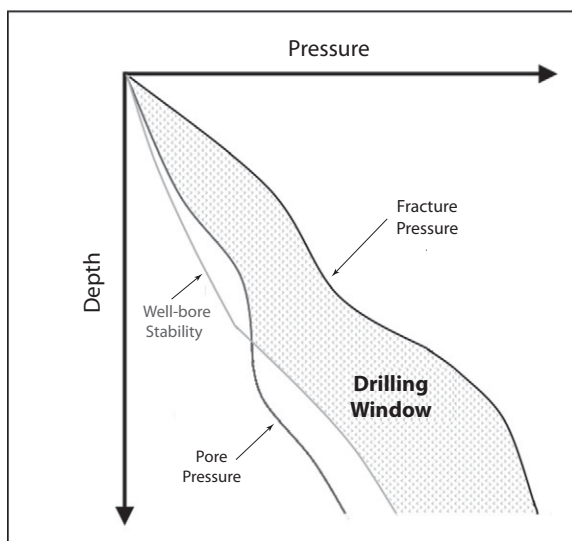


Figure 2.1 The drilling window is the area between the fracture pressure and the pore pressure/well-bore stability.

Controlling the ECD within the upper and lower limits of the window is often referred to as *constant bottom-hole pressure* (CBP) management. It takes five potential approaches, only the last two of which are part of normal field operations and are discussed here:

- Use a drilling fluid with the lowest possible ECD. As previously noted, this falls outside the discussions in this book, but that does not reduce the importance of the friction loss characteristic of the drilling fluid.
- Change the azimuth of a directional hole to modify bore-hole stress.
- Change the well-bore geometry.
- Impress surface choke pressure on the annulus of the well.
- Change the pumping rate to increase or decrease the circulating friction pressure.

Techniques for impressing surface pressure during steady-state operations vary, and they are discussed in detail in the following chapters. However, some other challenges are common to all the techniques.

2.2.1 Chokes

CBP operations that control bottom-hole pressure with a low mud density and impressed surface pressure require a means of quickly changing the impressed pressure. A choke on the annulus flow has been the simplest and quickest-reacting method of control. The response time of chokes under either computer or hydraulic control is normally adequate for the inertia involved in the drilling system. Annulus-to-bit response time in CBP operations varies only with depth, since there is no gas bubble, as in well-control operations, to cause a fluid density variation. In CBP operations, the reliability of choke response and the response time are critical elements.

2.2.2 Pumps

Starting and stopping the pumps cause a major change in ECD. Pump ramp-up and ramp-down speed are important in all operations. Most of the computer-controlled systems can follow a slow (+20 sec) ramp-up or -down of pumps. What is more difficult to follow is a quick shutdown of a pump or an immediate startup of the pump. Some of the systems use a special pump to help buffer the mud pump on a quick shutdown. The CPB plan should control the ramp-up and -down rate of the rig mud pump. The term “ramp” refers to smooth change in pump rate. In many cases the “ramp” is actually a series of steps in pump rate. This can be a critical point in operations and ramp or step should be clearly specified.

2.2.3 Pipe Movement

Pipe movement, especially on connections and trips, has a major effect on the ECD. When the pump is running, pipe movement down causes a significant increase in bottom-hole pressure below the bit. Likewise, when the pump is off, upward movement of the pipe

causes a swabbing pressure that can significantly reduce bottom-hole pressure. The CBP plan should contain procedures to limit the speed of pipe movement and correct for the pressure surges. This is further discussed in Section 2.5.

2.2.4 “Ballooning”

Ballooning can cause significant nonproductive time. A plastic formation may take some drilling fluid when circulating (or with pipe movement) and return it when the pressure is released. The effect is similar to a leak-off test. This is noticeable when the pumps are turned off for a connection or trip. The well flows a small stream that initially appears to be the start of a well kick. Within a half hour or more, it is evident that the flow is not increasing or actually decreasing, and it can be concluded that this is well-bore ballooning and not the start of a well kick. It is important that the CBP plan and the operator’s representative have some algorithm or plan to identify ballooning and incipient well kicks to limit NPT.

2.2.5 Precision

How important is it to avoid any loss or minor well flow? Most formations are plastic enough to recover from some lost circulation. Is there H_2S gas in the formation or some other condition where trip gas or a small gas flow is critical? What is critical about a small loss of mud? The answer to these questions affects the cost of equipment and the NPT.

2.2.6 Well Control

In CBP operations where the well is operated as a closed system, well control is a minor add-on to the system. However, CBP planning is to avoid well kicks; and if they should occur, they should be caught quickly with a very limited kick size. Unlike dual-gradient drilling, where the mud density is kept at a maximum, in CBP operations, mud density is at a minimum, so the intensity of the kick could be a critical factor.

All CBP operations should have a dual plan, one plan for controlling a minor influx as a method of operation with no NPT and

another plan for a kick of high intensity, where some loss of time will occur during the kill procedure.

2.2.7 Lag Time

Lag time is a factor to be considered any time the surface choke pressure, pump rate, or pipe movement is considered. The best practical solution to bit-to-surface time is to watch the flow line when the pump is off and see how long it takes for the flow to start after the drill pipe is lowered. It should approach 1 sec/1000 ft of measured depth.

2.3 Total Lost Circulation

Total lost circulation occurs as a result of a weaker formation or open fractures or voids. In case of total lost circulation, the down-hole pressure to lose mud or have a well kick may be the same and raises the problem of how to drill through the zone safely with minimum cost and lost time. In these cases, managed pressure drilling is a bit of a misnomer. It is actually a way of controlling surface pressure while suffering uncontrolled losses down the hole.

In the Austin Chalk, where some of the advanced ideas were developed, conventional mud cap drilling was used for many years. In this method, a mud that has higher gradient than the formation pressure would be used in the annulus. The mud balances the reservoir pressure at some (uncontrollable) depth. The disadvantage of this technique is that the bottom-hole pressure cannot be monitored directly. When gas breaks through the mud cap, it reaches the surface with little warning. This could lead to very high surface pressures that approach or exceed the rated working pressures of the surface control equipment. When gas breaks through, more heavy mud is bullheaded down the annulus, leading to a continuous cycle of loss and kick.

The pressurized mud cap drilling (PMCD) technique uses a drilling fluid in the mud cap that exerts a lower pressure than in the annulus and monitors the ensuing pressure at the surface (Figure 2.2). The surface annular pressure indicates what is happening with the mud cap.

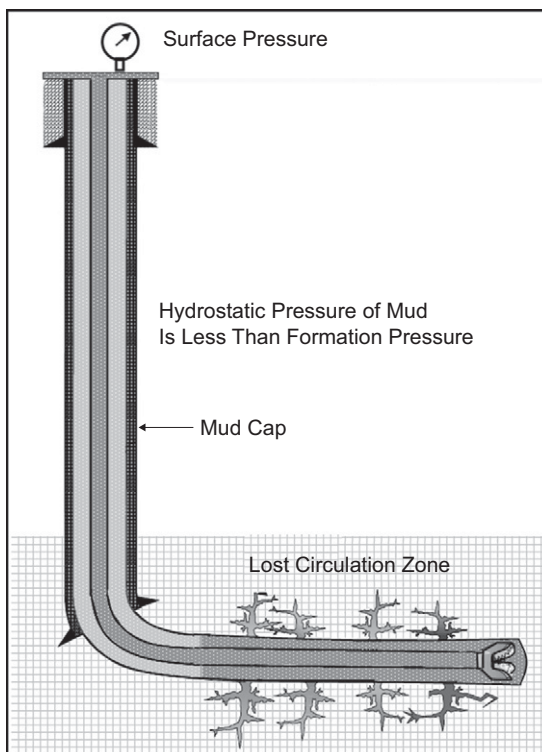


Figure 2.2 In pressurized mud cap drilling, the hydrostatic pressure of the mud cap is less than the formation pressure; therefore, the formation exerts pressure at the surface.

The reservoir is controlled by the pressure exerted by the column of mud with the addition of surface pressure. The reservoir pressure is now controlled by the mud cap, regardless of what is happening with each of the fracture zones. The same basic concept of PMCD is used in a version of marine dual-density drilling where there is a cap of either low- or high-density drilling fluid in the riser.

The four most important “mechanical” elements of PMCD are the rotating control device, a source of adequate expendable drilling fluid, the annular mud cap fluid, and the pressure monitoring system for the annulus mud cap.

2.4 Deepwater Marine Drilling

Excessive pressure from the long column of drilling fluid in the riser can cause lost circulation in the surface hole. In the following discussion, it is helpful to remember that most shallow marine formations are plastic and fractures will close when the pressure is relieved.

The following discussion is primarily about water and gas flows as a basic problem in dual-gradient or riserless drilling. Most dual-gradient or riserless operations should be able to handle a small well kick. The problem arises with large well kicks, where any additional pressure at the casing shoe needs to be carefully monitored. The details of controlling well kicks are somewhat different in dual-gradient systems. These details are discussed in Chapter 8, “Dual-Gradient Drilling.”

2.4.1 The Problem in the Surface Hole

Shallow marine sediments contain high-permeability water and gas sands. The shallow sediment, clays, and loosely consolidated sands have a pore pressure that closely equals the overburden pressure from the seawater column plus the pressure exerted as the result of the bulk density of the unconsolidated sediments. As the hole gets

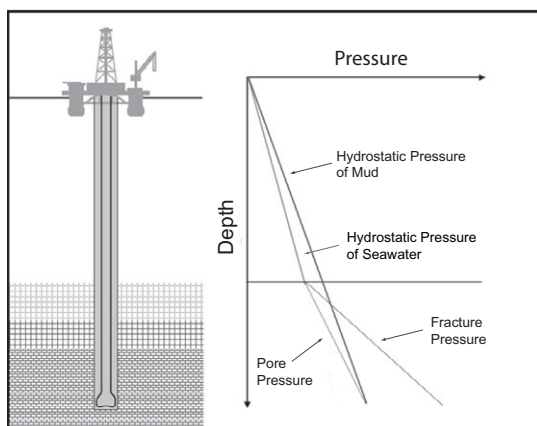


Figure 2.3 While drilling the surface hole with a riser, the hydrostatic pressure of mud in the riser may exceed the fracture pressure.

deeper, the sediments are more compacted, the bulk density increases, and so does the formation pressure in the sands. The fracture pressure changes from simple overburden pressure to a more complex value.

If the well is drilled on land or in very shallow water, the column of drilling fluid could be weighted to just below the overburden or fracture pressure to contain any pressure within a sand formation. Casing finally has to be set at some reasonable depth. In deepwater drilling, the pressure exerted by a heavier drilling fluid in the riser, or surface casing if the blowout preventer (BOP) stack is on the floor, causes lost returns. The heavier mud in the riser requires a shallower casing seat and several extra casing strings.

The present solutions are to either dump the drilling fluid to the seabed and eliminate the riser pressure problem or place a pump on the seabed to return drilling fluids to the drilling vessel or platform (Figure 2.4). Other chapters describe the process of a seafloor pump.

2.4.2 Excessive Casing Strings

As the hole gets deeper, the problem remains of how to avoid excessive strings of casing because of the pressure from the drilling fluid

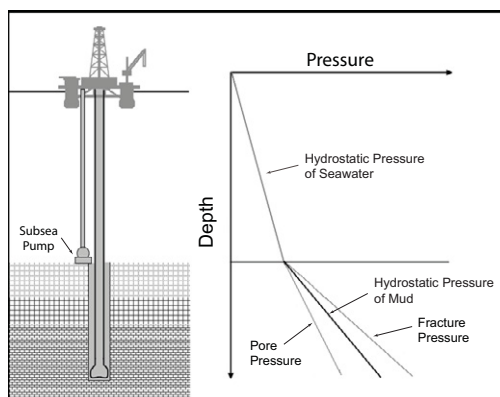


Figure 2.4 A subsea pump equalizes the annular pressure with the hydrostatic pressure of the seawater at the seabed, therefore, allowing drilling with heavier drilling fluid.

in the riser. As the hole gets deeper, typically, the mud density in the riser increases, increasing the pressure differential between the riser fluid and the seawater outside of it. The typical solution is simply to run more casing strings. Several efforts are underway to use a modified mud column in the riser to resolve this problem, as described previously under PMCD. This is described in detail later in Chapters 8 and 10.

2.4.3 U-Tube Effect in Riserless or Limited Riser Operations

A U-tube effect on connections occurs when the pump is turned off (Figure 2.5). At static conditions, the hydrostatic pressure of the drilling fluid balances the hydrostatic pressure of seawater while drilling riserless or using a subsea pump. The drilling fluid is heavier than seawater; therefore, a lower height of drilling fluid is

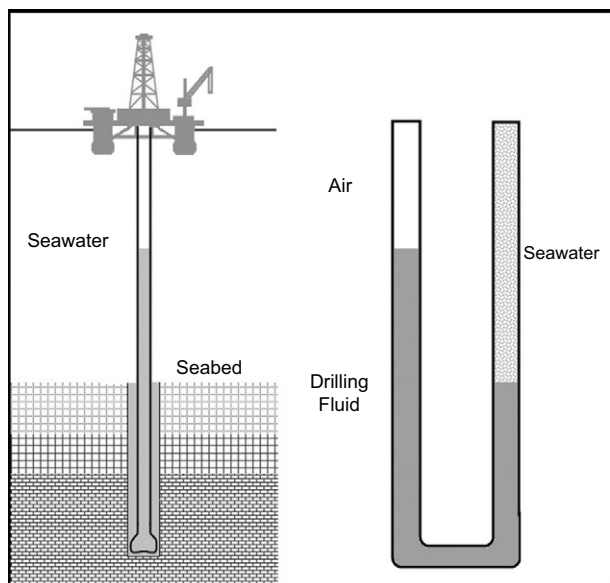


Figure 2.5 At static conditions, the height of the mud in the riser drops to balance the hydrostatic pressure of the seawater at the seabed.

needed. The “extra” mud from the drill pipe is pumped to the pits by the subsea pump or dumped to the seafloor.

In 5000 ft of water, with 12-ppg drill-pipe mud and a 5½-in. drill pipe, the U-tube effect on a connection is

$$\text{Displaced volume of mud} = (\text{Drill-pipe capacity}) \times (L - H) \quad (2.1)$$

where

L = riser length

H = height of the mud column to balance the seawater column

$$H = \frac{\rho_w L}{\rho_m} \quad (2.2)$$

ρ_m = density of mud

ρ_w = density of seawater

For example, the volume of mud displacement while drilling in water depth of 5000 ft with a seawater density of 8.6 ppg, mud weight of 12.0 ppg, and drill-pipe capacity of 1 gal/ft is

$$H = \frac{8.6 \times 5000}{12}$$

$$H = 3583 \text{ ft}$$

$$\text{Displaced volume of mud} = 1 \text{ gal/ft} (5000 - 3583) \text{ ft}$$

$$\text{Displaced volume of mud} = 1417 \text{ gal} = 34 \text{ bbl}$$

Given enough time, stabilization between the hydrostatic pressure of drilling fluid and the seawater is reached. The discharge rate of the mud to the seabed depends on the mud's properties, water depth, and well geometry. Figure 2.6 illustrates the effect of mud weight on the mud level drop-off versus time.

Because of inertia and drag, the mud displacement is somewhat less than the theoretical value.

- The U-tube effect masks the start of a well kick on a connection or when the pump is slowed down.
- The connection gas can mask the beginning of a problem since the air from the empty drill pipe is mixed in the annulus and appears to be connection gas or masks connection gas.

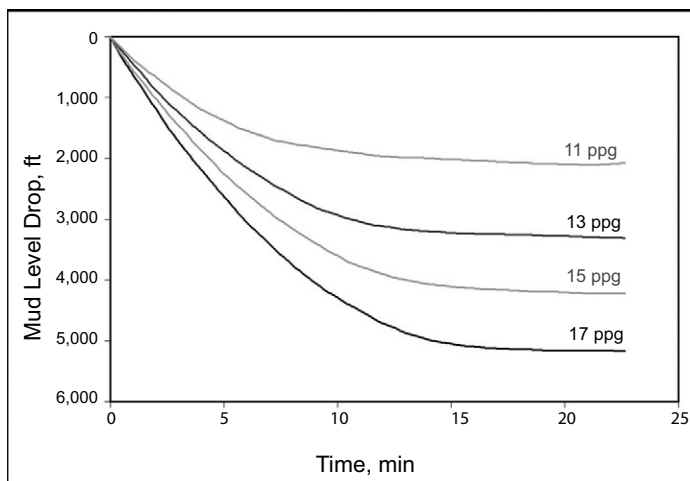


Figure 2.6 The density of the drilling fluid affects the height of the mud in the drill string and the time required to reach pressure stabilization. (After Johansen, 2000.)

The compensating factor is that, on a practical level, the U-tube while drilling does not appear to be a significant problem at this time, even though it can make annulus flow calculations difficult.

2.4.4 Hydrostatic Control Valve

To prevent the U-tube effect, a spring-operated float can be put in the bottom of the drill pipe (Figure 2.7). This is called by various names: *hydraulic control valve*, *bottom-hole pressure valve*, and *drill-pipe pressure valve* are a few. The spring or hydraulic control on the valve needs to be strong enough to hold the column of mud in the drill pipe equal to the riser length against the pressure differential exerted between seawater and the drilling fluid.

2.4.5 Annular Pressure Changes (ECD Problems)

The dual-gradient system is subject to the same annular pressure loss problems as any other drilling operation. When the pump is

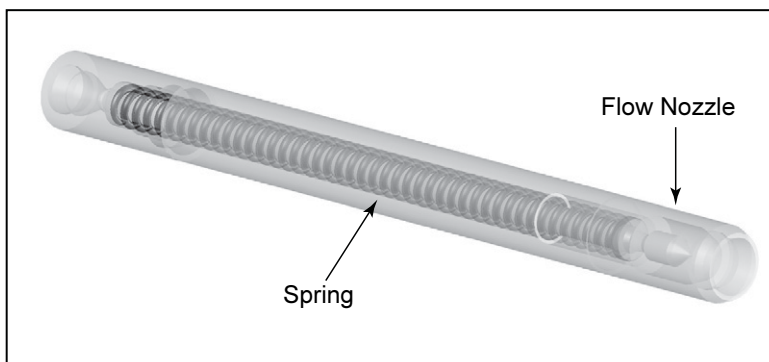


Figure 2.7 Hydraulic control valves prevent the U-tube effect when the pump is off. (After Smith et al., 1999.)

turned off, the bottom-hole pressure drops. When pipe is picked up for a connection, the bottom-hole pressure drops some more. The reverse occurs when running pipe back in the hole or turning on the pump. Surging on a floating vessel may also have some minor annular pressure effect.

2.4.6 Well-Bore Ballooning

Well-bore ballooning is discussed in Chapter 1. It occurs when the fracture pressure is approached or exceeded in the plastic marine formations. The determination of ballooning depends on accurate measurement of a very small flow when the pump is turned off.

While it occurs in drilling with dual-gradient systems, it is difficult to measure and the procedures with the subsea pump may tend to mask a very minor flow from the annulus. The problem of whether the flow-back is an incipient well kick still remains. In the case of “pump and dump,” ballooning is more difficult to measure.

2.4.7 Well Control

Dual-gradient technology allows the casing point to be deferred to deeper in the well by allowing heavier drilling fluid in the well. It

does not increase the fracture gradient at the conductor pipe or at the last casing shoe nor does it change pore pressure. Therefore, the dual-gradient drilling technique implies that the mud density always be as high as possible. That is the pressure in the well bore, allowing for surges, pipe movement, and pump rate, changes to be as close to the lowest fracture pressure as possible.

The challenge with dual-gradient technology and well kicks is that, if the well is shut in against a high-intensity kick or high kick influx, a limited pressure margin remains against lost circulation:

- *Kick intensity.* The pore pressure/well-bore pressure differential driving a well kick must be predicted by the operator using geology, history, or drilling data and casing set before the pore pressures exceeds the up-hole fracture pressure.
- *Influx volume.* This is a matter of quick response or detection.

In the shallow part of the well, a riserless dual-gradient system cannot be shut in without risking lost circulation into the shallow clay and sand. Present riserless systems allow the kick to be “dumped” until some heavier mud can be circulated down the drill pipe and into the open hole. The limit to the situation is not so much the dual-gradient system as the casing shoe not standing extra pressure. This is why it is important to have the highest-density fluid practical in the hole and to quickly detect the flow. The drilling fluid density gives the greatest balance against down-hole pore pressure with a minimum increase in pressure at the shoe.

With casing set deeper and the riser engaged, if the well kicks, extra pressure from fluid in the riser can help limit the influx of water or gas until heavier mud can be pumped into the well. There are two approaches to the problem:

1. With a pressurized riser or the wellhead on the vessel and casing to the sea bottom, the rotating head or preventers, along with a choked system, can use some basic well-control practices to control a kick. Again, it is important to note that the volume of the kick, or more properly the length of the kick, and the kick intensity affect the annular pressure. Kick size must be limited.

2. With a riser containing fluids of two or more densities, fluid density in the riser can be increased through a riser kill line to increase the annular pressure exerted by the fluid in the riser. This may be a quick solution, but it increases the pressure at the casing shoe disproportionately.

2.5 Connections and Trips

Connections and trips are the real daily technical issues with MPD operations. The (more or less) steady-state operation during drilling operations lends itself to simple control and reasonable prediction of influxes or losses with modern recording instruments. Handling the upsets, caused by pipe movement and the pump going off and on, is the key to maintaining control of the drilling process.

The annular pressure loss calculations shown in Section 2.6 describe how the pressure loss is affected by the velocity of the drilling fluid flow. It is clear that there is a difference in bore-hole pressure between pump on and pump off, the ECD (Figure 2.8). Drill-pipe movement on connections and trips also affects the pressure loss.

- *Downward* movement of pipe increases the annular pressure loss (APL) below the bit, because drilling fluid is displaced at a higher velocity past the collars, called “surging.” There is also an effect between the drill pipe and the open hole or casing, but that is not as pronounced. With the pump running, drilling fluid passes the bit and drill string at higher velocity and increases the APL.
- *Upward* movement of pipe decreases the pressure below the bit because the drilling fluid must flow down past the collar string and bit to fill the hole, called “swabbing.”
 - Running the pump decreases the swabbing effect and in general reduces the pressure loss below the bit.
 - Upward movement of pipe while not circulating produces the minimum bottom-hole pressure because of the swabbing effect of the collars and bit.

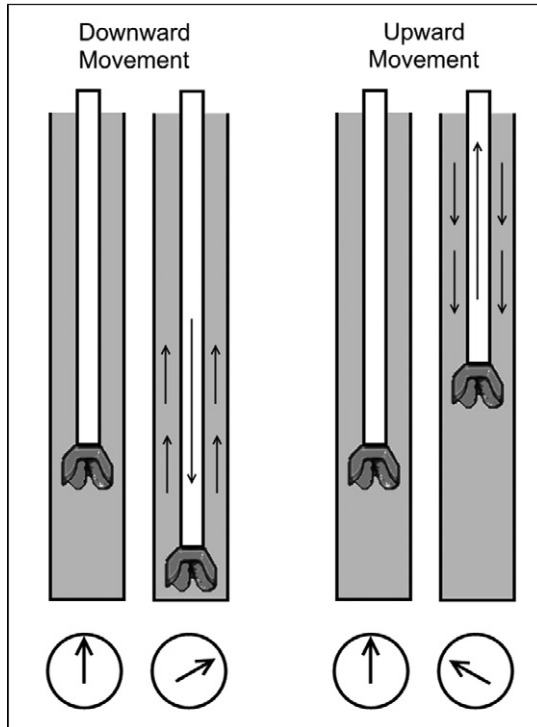


Figure 2.8 Pipe movement affects bottom-hole pressure. Downward movement increases bottom-hole pressure and upward movement decreases bottom-hole pressure.

The pipe movement effects are greatest when the hole is in gauge or undergauge, or the bit is balled. This is generally most prominent on connections.

It is considered good drilling practice to keep the pump on during a connection until the pipe is in the slips. Fast pipe movement always has the potential of causing lost circulation, starting a well kick, or at least, allowing excessive connection gas.

One challenge to MPD operations is control of the pump ramp speed and pipe movement during connections. Since both items are controlled by the driller, the emphasis has to be on careful explanations and careful supervision.

Trips pose a particular problem with MPD processes because the system is often tightly balanced among pore pressure, hole problems, and lost circulation. Trip procedures can involve stripping, snubbing, or killing the well with drilling fluid, mud cap, or an annular valve. Longer-term completion may include setting a packer.

Most MPD operations go through a stripping phase. While there are objections to stripping all the way out of the hole, based on wear of the stripping elements and the time involved, the major problem is at the “pipe light” section at the top of the hole. This finally may require a mud cap, killing the well, or snubbing.

For the constant bottom-hole pressure operations, the best solution is the annular valve (Figure 2.9). The bit is stripped up through the valve; it is closed. The well-bore pressure is contained below the valve, so surface operations can continue in a normal manner and at a normal rate with no danger of a well kick. Down-hole casing valves have a high initial cost and require a larger hole size. The reduction in NPT when using them quickly can make up the difference. The

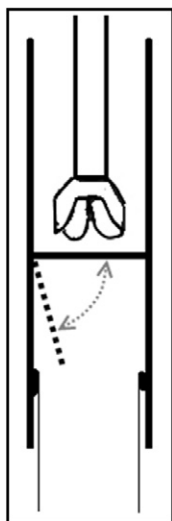


Figure 2.9 The down-hole casing valve closes when the drill pipe is tripped out and prevents pressure communication.

annular pressure valve is described in Chapter 9, “Equipment Common to MPD Operations.”

Pressurized mud cap operations have generally tripped with a mud cap, since it is already in place. Generally, under mud cap conditions, it is impractical to kill the well. The challenge with mud caps is to rebalance them and start drilling again after a trip without excessive lost returns or NPT-circulating well kicks. Mud caps are described in Chapter 7, “Mud Cap Drilling.”

Dual-gradient systems in the upper hole have generally taken the route of killing the well. Since gas or water flows are not potential production zones, little damage is done to kill them with a drilling fluid. As dual-gradient drilling goes deeper, it probably will be worthwhile to use an annular pressure valve.

2.6 Annular Pressure Loss and Hydraulics

Hydraulics is the branch of engineering concerned with the motion of fluids. Hydraulics enables us to investigate how the flow of a fluid through the drill string, bit, and annulus affects the pump pressure. Prediction of the dynamic system’s pressure loss is a matter of rheology and flow rate. Hence, to predict the pressure loss throughout a circulation system, the fluid’s rheological properties should be correlated with the flow rate. Therefore, to optimize drilling fluid hydraulics, it is imperative to control the fluid’s rheological properties and flow rates. A basic discussion of rheology is found in Appendix B.

In conventional hydraulics calculations, fluid properties are assumed to be constant. In shallow wells, errors resulting from such an assumption are relatively negligible. However, in high-pressure and high-temperature (HPHT), extended-reach, and deepwater wells, ignoring the variations of mud properties with respect to temperature and pressure strongly affects the accuracy of hydraulic calculations.

In extreme cases, it may be necessary to change the well-bore and drill-pipe diameters to obtain a reasonable APL. Also, changing the drilling fluid might reduce the APL, as, for example, going to a clear dense fluid instead of a conventional weighted drilling fluid.

2.6.1 Equivalent Circulating Density

When circulating a drilling fluid, friction increases the well-bore pressure over the static condition. The equivalent circulating density at any point accounts for the sum of hydrostatic pressure of a column of fluid and frictional pressure loss above that point. Thus, at any point of interest, the dynamic equivalent density, ECD, is higher than the static equivalent mud density, EMD. The ECD is calculated as

$$\text{ECD} = \text{EMD} + \frac{\Delta P}{K \times \text{TVD}} \quad (2.3)$$

where

EMD = static equivalent density of a column of fluid that is open to the atmosphere

ΔP = frictional pressure loss

TVD = true vertical depth

K = constant, in the English system is equal to 0.052 and in the metric system is equal to 0.01

When changes in viscosity with temperature and pressure are taken into account, the calculation of ECD becomes more complicated, especially in HPHT wells. To avoid kicks and losses, particularly in wells that have a narrow window between the pore pressure gradient and fracture gradient, constant monitoring of the ECD is a must.

2.6.2 Historical Calculation of the ΔP in APL

While hydraulic theory is not new, before field computers were available, charts or a slide rule were used to calculate the annular ΔP value. It was simplified on the field level to where a small slide rule and a two-speed VG meter could give some sort of answer. The details of Reynolds number and friction factors were not practical for the time and equipment available on the drill rig. The reader may be familiar with the following terms.

For Bingham flow,

$$\Delta P = \frac{\text{YPL}}{225(d_b - d_p)} + \frac{\mu_{\text{app}} \times v \times L}{1500(d_b - d_p)^2} \quad (2.4)$$

Since the second part of the term is small, often the first part is used for the estimate of annular pressure loss. (Annular fluid was assumed to be in laminar flow.)

For turbulent flow,

$$\Delta P = \frac{\rho v^2 L}{5000(d_b - d_p)} \quad (2.5)$$

where

ΔP = pressure drop, in psi, annular pressure loss

L = length, ft

d_b = hole diameter, in.

d_p = pipe diameter, in.

ρ = mud density, ppg

YP = yield point, lb/100 ft² ($n - R_{300}$)

μ_{app} = plastic viscosity, cp ($R_{600}/2$)

v = annular velocity, ft/sec

R_{600} and R_{300} = VG meter readings at 600 and 300 rpm

These equations give only estimated answers that generally tend to be high—greater than the actual value. This is particularly true when using the Bingham term to estimate ΔP (annular pressure loss) caused by pipe movement.

2.6.3 Annular Pressure Loss Calculations

Annular pressure loss is a major challenge when using constant bottom-hole pressure. The APL at any interval of the hole tends to be related to velocity. In theory then, the APL can be manipulated by changing the pump rate. In practice, there are some limits to this because of drilling and hole cleaning requirements.

The following mathematical discussion, first, goes through a classic derivation of annular pressure loss during circulating a hole without drill-pipe movement. This defines the pump on/off condition. Second, in considering the effect of pipe movement, in all MPD operations, a float or nonreturn valve (NRV) is at the bit, so the bottom-hole assembly acts as a piston. Pump on/off conditions

and pipe movement cause the major variations in APL due to fluid velocity.

With the pump on, as the pipe is lowered, as after a connection, the velocity past the bottom-hole assembly (BHA) and drill pipe must increase, increasing the APL. When the pipe is raised, the velocity decreases as some of the drilling fluid fills the voided space, and this decreases the APL. The APL is finally affected by the speed of the pipe movement.

With the pump off, as the pipe is lowered, as after a connection, the APL and the velocity past the BHA and drill pipe are increased, caused by displacement of fluid from the open bore. Likewise, if the pipe is raised with the pump off, *the APL goes negative*.

Reynolds Number

The Reynolds number is the ratio of inertial forces to viscous forces. The Reynolds number is a dimensionless number used to categorize the fluids systems in which the effect of viscosity is important in controlling the velocities or the flow pattern of a fluid. Mathematically, the Reynolds number, N_{Re} , is defined as

$$N_{Re} = \frac{\rho v d}{\mu} \quad (2.6)$$

where

ρ = density

v = velocity

d = diameter

μ = viscosity

The Reynolds number is used to determine whether a fluid is in laminar or turbulent flow. Based on the API 13D recommendations, it is assumed that a Reynolds number less than or equal to 2100 indicates laminar flow, and a Reynolds number greater than 2100 indicates turbulent flow. In field units, the equation for calculating the Reynolds number becomes

$$N_{Re} = \frac{928 \rho v d}{\mu} \quad (2.7)$$

where

- ρ = density, ppg
- v = velocity, ft/sec
- d = diameter, in.
- μ = viscosity, cp

Depending on which rheological model is used, the associated correlation for the Reynolds number may vary. Table 2.1 presents the different expressions, which correlate the Reynolds number.

Friction Factor

Once the fluid's flow pattern is established, the frictional pressure losses are to be determined. The most common pressure loss correlations are based on a dimensionless quantity known as the *friction factor*. The friction factor, in general form, is defined as (Lal, 1983)

$$f = \frac{F_k}{AE_k} \quad (2.8)$$

where

- F_k = force caused by fluid movement exerted on the conduit walls
- A = characteristic area of the conduit
- E_k = kinetic energy per unit volume

For pipe flow, accounting for the shear stress and force exerted on the conduit walls and substituting kinetic energy expression for E_k yields

$$f = \frac{d}{2\rho v^2} \times \frac{dp_f}{dL} \quad (2.9)$$

This equation is known as the *Fanning equation*, and the friction factor defined by this equation is called the *Fanning friction factor*. The Fanning friction factor is a dimensionless number used in studying fluid friction in pipes. This friction factor is an indication of the resistance to fluid flow at the pipe wall.

The Darcy–Weisbach friction factor is another dimensionless number used in internal flow calculations. The linear relationship

Table 2.1 Reynolds Number Terms

Pipe	Annulus
Newtonian model:	
$N_{Re} = \frac{928\rho v_p d}{\mu_a}$	$N_{Re} = \frac{757\rho v_a (d_2 - d_1)}{\mu_a}$
Bingham plastic model:	
$N_{Re} = \frac{928\rho v_p d}{\mu_a}$	$N_{Re} = \frac{757\rho v_a (d_2 - d_1)}{\mu_a}$
Power law model:	
$N_{Re} = \frac{89,100\rho v_p^{2-n}}{k} \left[\frac{0.0416d_p}{3 + \frac{1}{n}} \right]^n$	$N_{Re} = \frac{109,000\rho v_a^{2-n}}{k} \left[\frac{0.0208(d_2 - d_1)}{2 + \frac{1}{n}} \right]^n$
API 13D model (2003):	
$N_{Re} = \frac{928\rho v_p d}{\mu_e}$	$N_{Re} = \frac{757\rho v_a (d_2 - d_1)}{\mu_e}$
$\mu_e = 100k_p \left[\frac{96v_p}{d_p} \right]^{n_p-1} \left[\frac{3n_p + 1}{4n_p} \right]^{n_p}$	$\mu_e = 100k_a \left[\frac{144v_a}{d_2 - d_1} \right]^{n_a-1} \left[\frac{2n_a + 1}{3n_a} \right]^{n_a}$
Herschel-Bulkley model:	
$N_{Re} = \left[\frac{2(3n+1)}{n} \right] \times$ $\left\{ \frac{\rho v_p^{(2-n)} \left(\frac{d_p}{2} \right)^n}{\tau_0 \left(\frac{d_p}{2v_p} \right)^n + k \left[\frac{(3n+1)}{nC_c} \right]^n} \right\}$	$N_{Re} = \left[\frac{4(2n+1)}{n} \right] \times$ $\left\{ \frac{\rho v_a^{(2-n)} \left(\frac{d_2 - d_1}{2} \right)^n}{\tau_0 \left(\frac{d_2 - d_1}{2v_a} \right)^n + k \left[\frac{2(2n+1)}{nC_a} \right]^n} \right\}$

between mean flow velocity and the pressure gradient is expressed by the Darcy friction factor as

$$f = \frac{\left(\frac{-dp}{dL} \right) \times d_b}{\frac{1}{2}\rho V^2} \quad (2.10)$$

where $(-dp/dL)$ is the pressure drop per unit length.

The Darcy friction factor, similar to the Fanning friction factor, can be evaluated by the use of various empirical or theoretical correlations for different conditions. It also can be obtained from charts, often referred to as *Moody diagrams*. Hence, the Darcy friction factor is sometimes called the *Moody friction factor*. The Moody friction factor can be obtained by plotting the Darcy friction factor as a function of Reynolds number and relative roughness. The Moody friction factor is four times larger than the Fanning friction factor; it is important to note, in a “friction factor” chart or equation, which one is referred to. Some of the proposed correlations for friction factor values are presented in Table 2.2.

Table 2.2 Friction Factor Terms

	Pipe	Annulus
Newtonian model:		
Laminar	$f_p = \frac{16}{N_{Re}}$	$f_p = \frac{16}{N_{Re}}$
Turbulent	$f_p = \frac{0.0791}{N_{Re}^{0.25}}$	$f_p = \frac{0.0791}{N_{Re}^{0.25}}$
Bingham plastic model:		
Laminar	$f_p = \frac{16}{N_{Re}}$	$f_p = \frac{16}{N_{Re}}$
Turbulent	$f_p = \frac{0.0791}{N_{Re}^{0.25}}$	$f_p = \frac{0.0791}{N_{Re}^{0.25}}$
Power law model:		
Laminar	—	—
Turbulent	$f_p = \frac{a}{N_{Re}^b}$	$f_a = \frac{a}{N_{Re}^b}$
	$a = \frac{\log(n) + 3.93}{50}$	$a = \frac{\log(n) + 3.93}{50}$
	$b = \frac{1.75 - \log(n)}{7}$	$b = \frac{1.75 - \log(n)}{7}$

Table 2.2 Friction Factor Terms *continued*

Pipe	Annulus
API 13D model (2003):	
Laminar	
$f_p = \frac{16}{N_{Re}}$	$f_a = \frac{24}{N_{Re}}$
Turbulent	
$f_p = \frac{a}{N_{Re}^b}$	$f_a = \frac{a}{N_{Re}^b}$
$a = \frac{\log(n_p) + 3.93}{50}$	$a = \frac{\log(n_a) + 3.93}{50}$
$b = \frac{1.75 - \log(n_p)}{7}$	$b = \frac{1.75 - \log(n_a)}{7}$
Herschel-Bulkley model:	
Turbulent	
$f_p = y(C_c N_{Re})^{-z}$	
$C_c = 1 - \left(\frac{1}{2n+1} \right) \times$	$C_a = 1 - \left(\frac{1}{n+1} \right) \times$
$\frac{\tau_0}{\tau_0 + k \left[\frac{(3n+1)q}{n \left(\frac{d_p}{2} \right)^3} \right]^n}$	$\frac{\tau_0}{\tau_0 + k \left\{ \left[\frac{2(2n+1)}{n \left(\frac{d_2}{2} - \frac{d_1}{2} \right)} \right] \times \left[\frac{q}{\left(\left(\frac{d_2}{2} \right)^2 - \left(\frac{d_1}{2} \right)^2 \right)} \right]^n \right\}}$

2.6.4 Hydraulics Equations

Once the friction factor is determined, using an appropriate correlation, the frictional pressure drop per unit length (dp/dL) can be calculated. Table 2.3 presents expressions that correlate the frictional pressure drop per unit length. The result then is plugged into the total pressure loss equation:

$$\Delta P = \left(\frac{dp}{dL} \right) \times \Delta L. \quad (2.11)$$

Table 2.3 Pressure Drop Terms

	Pipe	Annulus
Newtonian model:		
Laminar	$\left(\frac{dp}{dL}\right) = \frac{\mu \bar{v}}{1500d^2}$	$\left(\frac{dp}{dL}\right) = \frac{\mu \bar{v}}{1000(d_2 - d_1)^2}$
Turbulent	$\left(\frac{dp}{dL}\right) = \frac{\rho^{0.75} \bar{v}^{1.75} \mu^{0.25}}{1800d^{1.25}}$	$\left(\frac{dp}{dL}\right) = \frac{\rho^{0.75} \bar{v}^{1.75} \mu^{0.25}}{1396(d_2 - d_1)^{1.25}}$
Bingham plastic model:		
Laminar	$\left(\frac{dp}{dL}\right) = \frac{\mu \bar{v}}{1500d^2} + \frac{\tau_y}{225d}$	$\left(\frac{dp}{dL}\right) = \frac{\mu \bar{v}}{1000(d_2 - d_1)^2} + \frac{\tau_y}{200(d_2 - d_1)}$
Turbulent	$\left(\frac{dp}{dL}\right) = \frac{\rho^{0.75} \bar{v}^{1.75} \mu^{0.25}}{1800d^{1.25}}$	$\left(\frac{dp}{dL}\right) = \frac{\rho^{0.75} \bar{v}^{1.75} \mu^{0.25}}{1396(d_2 - d_1)^{1.25}}$
Power law model:		
Laminar	$\left(\frac{dp}{dL}\right) = \frac{K \bar{v}^n \left(\frac{3+1/n}{0.0416}\right)}{144,000d^{1+n}}$	$\left(\frac{dp}{dL}\right) = \frac{K \bar{v}^n \left(\frac{2+1/n}{0.0208}\right)}{144,000(d_2 - d_1)^{1+n}}$
Turbulent	$\left(\frac{dp}{dL}\right) = \frac{f_p \bar{v}^2 \rho}{25.8d}$	$\left(\frac{dp}{dL}\right) = \frac{f_a \bar{v}^2 \rho}{21.1(d_2 - d_1)}$
API 13D model (2003):		
Laminar	$\left(\frac{dp}{dL}\right) = \frac{f_p \bar{v}^2 \rho}{25.8d}$	$\left(\frac{dp}{dL}\right) = \frac{f_a \bar{v}^2 \rho}{25.8(d_2 - d_1)}$
Turbulent	$\left(\frac{dp}{dL}\right) = \frac{f_p \bar{v}^2 \rho}{25.8d}$	$\left(\frac{dp}{dL}\right) = \frac{f_a \bar{v}^2 \rho}{25.8(d_2 - d_1)}$
Herschel–Bulkley model:		
Laminar	$\left(\frac{dp}{dL}\right) = \frac{4k}{14,400d} \times \left\{ \left(\frac{\tau_0}{k}\right) + \left[\left(\frac{3n+1}{nC_c}\right) \left(\frac{8q}{d^3}\right) \right]^n \right\}$	$\left(\frac{dp}{dL}\right) = \frac{4k}{14,400(d_2 - d_1)} \times \left\{ \left(\frac{\tau_0}{k}\right) + \left[\left(\frac{16(2n+1)}{nC_a(d_2 - d_1)}\right) \left(\frac{q}{(d_2^2 - d_1^2)}\right) \right]^n \right\}$
Turbulent	$\left(\frac{dp}{dL}\right) = \frac{f_p q^2 \rho}{144\pi^2 d^5}$	$\left(\frac{dp}{dL}\right) = \frac{f_a q^2 \rho}{144\pi^2 (d_2 - d_1)(d_2^2 - d_1^2)}$

2.6.5 Annular Frictional Pressure Loss Calculation, ΔP_a

The mathematical expression for the total pressure loss of the system, also known as the *pump pressure* (ΔP_p), is given as

$$\Delta P_p = \Delta P_s + \Delta P_{ds} + \Delta P_b + \Delta P_a \quad (2.12)$$

The total frictional pressure loss of a system is a function of several factors, such as the fluid's rheological behavior, fluid's flow regime (laminar, turbulent, or transient), fluid's properties (density and viscosity), flow rate, drill-string configuration, and well-bore geometry. This discussion considers only the pressure loss in the annulus. The procedure for calculating the frictional pressure loss can be summarized as follows:

- Choose the rheological model that fits the data best.
- Use the flow rate and the well-bore geometry to calculate the velocity of the fluid.
- Calculate the Reynolds number to determine if the flow regime is laminar or turbulent.
- Calculate the friction factor.
- Use an appropriate rheological model correlation to calculate the frictional pressure loss.

API RP 13D (2006) recommends the Herschel–Bulkley model, which is more rigorous. For simplicity in this chapter, pressure drop is calculated using API RP 13D (2003) and a Reynolds number of 2100 is considered as the boundary of turbulent and laminar flow. An example of how to calculate the total pressure loss in the annulus follows.

Example 2.1

Given the pump in Figure 2.10 and the following data:

Mud weight = 12.5 ppg.

Circulation rate = 280 gpm.

TVD = 12,000 ft.

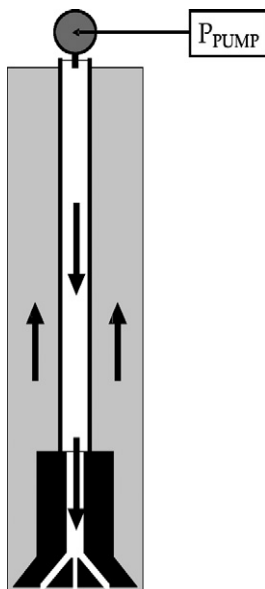


Figure 2.10 Example 2.1.

The relevant rotational viscometer readings are as follows:

$$R_3 = 3 \text{ (at 3 rpm).}$$

$$R_{100} = 20 \text{ (at 100 rpm).}$$

$$R_{300} = 39 \text{ (at 300 rpm).}$$

$$R_{600} = 65 \text{ (at 600 rpm).}$$

At each location (opposite the drill collars and apposite the drill pipe), using the API 13D (2003) model, calculate the pump pressure and ECD at the bottom.

Solution to Example 2.1

The pressure drop around the drill collars is

Drill collars OD = 6.5 in.

Drill collars ID = 2.5 in.

$L = 600$ ft.

The pressure drop between the hole and the drill collars is

Drill collars OD = 6.5 in.

Hole diameter = 8.5 in.

$L = 600$ ft.

Based on the viscometer's reading at 300 and 600 rpm, the flow consistency index and the flow behavior index for API 13D (2003) are to be determined:

$$n = 0.657 \log \left(\frac{R_{100}}{R_3} \right) = 0.657 \log \left(\frac{20}{3} \right) = 0.5413$$

$$f = \frac{24}{N_{\text{Re}}} = \frac{24}{1600} = 0.01500$$

$$K = \frac{5.11 R_{100}}{170.2^n} = \frac{5.11 \times 20}{170.2^{0.5413}} = 6.336 \frac{\text{dyne sec}^n}{\text{cm}^2}$$

$$V = \frac{0.408Q}{D_2^2 - D_1^2} = \frac{0.408 \times 280}{8.5^2 - 6.5^2} = 3.808 \text{ ft/sec}$$

The effective viscosity and, consequently, the Reynolds number are calculated as

$$\begin{aligned} \mu_e &= 100K \left(\frac{144V}{D_2 - D_1} \right)^{n-1} \left(\frac{2n+1}{3n} \right)^n \rightarrow \mu_e \\ &= 100 \times 6.336 \left(\frac{144 \times 3.808}{8.5 - 6.5} \right)^{0.5413-1} \left(\frac{2 \times 0.5413 + 1}{3 \times 0.5413} \right)^{0.5413} = 55.20 \text{ cP} \end{aligned}$$

$$N_{\text{Re}} = \frac{928(D_2 - D_1)V\rho}{\mu_e} = \frac{928(8.5 - 6.5) \times 3.808 \times 12.5}{55.20} = 1600$$

$N_{\text{Re}} < 2100 \rightarrow$ laminar flow; hence, the friction factor is calculated as

$$f = \frac{24}{N_{\text{Re}}} = \frac{24}{1600} = 0.01500$$

The pressure loss per unit length is calculated as

$$\left(\frac{dP}{dL} \right) = \frac{fV^2\rho}{25.81(D_2 - D_1)} = \frac{0.01500 \times 3.808^2 \times 12.5}{25.81(8.5 - 6.5)} = 0.05266 \text{ psi/ft}$$

which yields

$$\Delta P = \left(\frac{dP}{dL} \right) \times \Delta L = 0.05266 \times 600 = 31.6 \text{ psi}$$

The total pressure loss between the hole and the collars, $P_{DC/Ann}$, is calculated to be 31.6 psi.

For the pressure drop between the hole and the pipe:

Drill-pipe OD = 4.5 in.

Hole diameter = 8.5 in.

$L = 11,400$ ft

Again, beginning with the flow consistency index and the flow behavior index,

$$n = 0.657 \log \left(\frac{R_{100}}{R_3} \right) = 0.657 \log \left(\frac{20}{3} \right) = 0.5413$$

$$K = \frac{5.11 R_{100}}{170.2^n} = \frac{5.11 \times 20}{170.2^{0.5413}} = 6.336 \frac{\text{dyne sec}^n}{\text{cm}^2}$$

The average bulk velocity is

$$V = \frac{0.408 Q}{D_2^2 - D_1^2} = \frac{0.408 \times 280}{8.5^2 - 4.5^2} = 2.197 \text{ ft/sec}$$

And the effective viscosity and, consequently, the Reynolds number are calculated as

$$\begin{aligned} \mu_e &= 100K \left(\frac{144V}{D_2 - D_1} \right)^{n-1} \left(\frac{2n+1}{3n} \right)^n \rightarrow \mu_e \\ &= 100 \times 6.336 \left(\frac{144 \times 2.197}{8.5 - 4.5} \right)^{0.5413-1} \left(\frac{2 \times 0.5413 + 1}{3 \times 0.5413} \right)^{0.5413} = 97.64 \text{ cP} \\ N_{Re} &= \frac{928(D_2 - D_1)V\rho}{\mu_e} = \frac{928(8.5 - 4.5) \times 2.197 \times 12.5}{97.64} = 1044 \end{aligned}$$

$N_{Re} < 2100 \rightarrow$ laminar flow; hence, the friction factor is calculated as

$$f = \frac{24}{N_{Re}} = \frac{24}{1044} = 0.02299$$

The pressure loss per unit length is calculated as

$$\left(\frac{dP}{dL}\right) = \frac{fV^2\rho}{25.81(D_2 - D_1)} = \frac{0.02299 \times 2.197^2 \times 12.5}{25.81(8.5 - 4.5)} = 0.01343 \text{ psi/ft}$$

which yields

$$\Delta P = \left(\frac{dP}{dL}\right) \times \Delta L = 0.01343 \times 11,400 = 153.2$$

The total pressure loss between the hole and the pipe, $\Delta P_{\text{DP/Ann}}$, is calculated to be 153.2 psi. The total pressure drop in the annulus is

$$\begin{aligned}\Delta P_a &= 32 \text{ psi} + 153 \text{ psi} \\ &= 185 \text{ psi}\end{aligned}$$

For the ECD at the bottom of the well,

$$\text{ECD} = \text{EMD} + \frac{\Delta P}{0.052 \times \text{TVD}} \rightarrow \text{ECD} = 12.5 + \frac{32 + 153}{0.052 \times 12,000}$$

$$\text{ECD} = 12.8 \text{ ppg}$$

2.7 The Effect of Pipe Movement

2.7.1 Pipe Movement Changes the Bottom-Hole Pressure

The purpose of MPD is to maintain annular pressure within an operational window to prevent problems. The pressure should be controlled during drilling and tripping. Pipe movement induces transient pressure in the well bore. If the transient pressure increases the bottom-hole pressure, it is referred to as a *pressure surge*; if transient pressure reduces the bottom-hole pressure, it is referred to as a *pressure swab*.

It is common to associate a pressure surge with moving the pipe into the hole, because, running down the hole, the pipe displaces the drilling fluid in the annulus and induces upward flow in the annulus. The upward flow of the drilling fluid increases the annular pressure. A pressure swab is associated with moving the pipe out of the hole. However, the transient nature of pressure and fluid movement in

the well bore may cause a surge or swab for either running into or out of the hole. While moving the pipe in the hole, the magnitude of pressure change should be calculated to prevent pressure-related problems, such as loss of circulation or swabbing kick into the well.

Initially, steady-state models were developed to determine the effect of pipe movement on the bottom-hole pressure. Bazer and Owens (1969) wrote monographs to assist field engineers to determine the pressure change while moving the pipe. The accuracy of steady-state models was limited to specific conditions. Detailed formulation of steady-state models is available from Brooks (1982).

Drilling into deeper formations with reduced well diameter intensifies the need of capturing the pressure change during pipe movement. Transient models were developed to simulate the relation between the pipe movement and pressure. Lal (1983) and Mitchell (1988) developed transient models, and readers are referred to their papers for more information.

Steady-state models assume that the pipe movement displaces the drilling fluid efficiently. These models require mud properties, well-bore geometry, and velocity of pipe movement to estimate the maximum pressure change in the well bore. Transient models aim to capture the bottom-hole pressure as a function of time. The maximum estimated pressure with transient models is related to the result of steady-state models. Although, in most cases, steady-state models give conservative results, transient models are believed to estimate pressure changes more accurately in deeper wells. Transient models consider the following factors to estimate pressure surge and swab:

- *Fluid properties* determine the flow behavior of drilling fluid in the annulus. Increasing the viscosity and gel strength of the drilling fluid increases the magnitude of surge and swab. The effect of temperature and pressure on the properties of drilling fluid should be considered to estimate pressure surge and swab.
- *Drilling fluid gels* sustain solids when the circulation stops. To start circulation or move the pipe in the well bore, initial pres-

sure is required to overcome the gel strength. Therefore, the initial movement of the pipe causes pressure fluctuation. After the gel breaks, pressure fluctuation depends on behavior of fluid. In general, the effect of gel strength on pressure fluctuation is more significant than viscosity.

- *Geometry of the well bore and pipe* create a flow passage for the drilling fluid. As the flow passage reduces, greater pressure fluctuation is created.
- The *velocity of the pipe* determines the rate that the drilling fluid displaces in the well bore and flow regime (Figure 2.11). In the field, the velocity of the pipe is controlled to prevent excessive pressure fluctuation. The velocity of the pipe is controlled to limit fluid flow in the laminar region. In the laminar region, the relationship between pipe velocity and induced pressure is linear. If the flow regime of fluid is in turbulent flow, the pressure fluctuation changes rapidly.

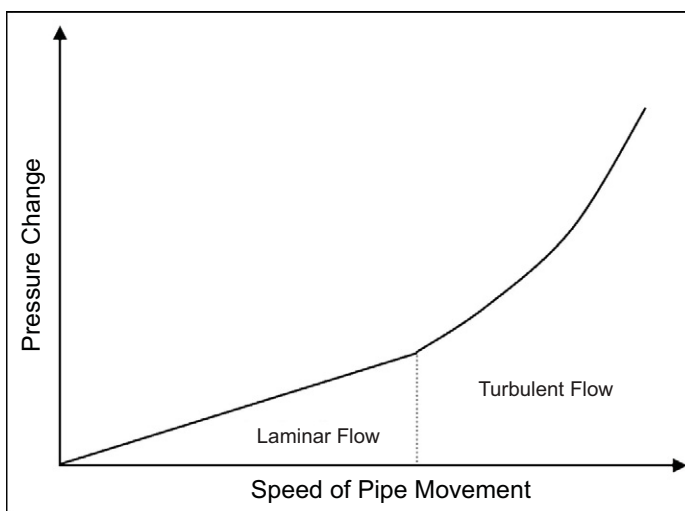


Figure 2.11 The pressure change in the annulus depends on the speed of the pipe movement and fluid flow pattern.

- *Compressibility of the drilling fluid and the well bore* dampens pressure fluctuation (Figure 2.12). Steady-state models neglect the effect of compressibility, which is assumed to be conservative. The volume of fluid and well bore changes with the pressure in the well bore and reduces the fluid velocity in the annulus. Because of lower fluid velocity, lower pressure fluctuation occurs in the well bore.
- *Fluid inertia* behaves against the change of pipe movement and intensifies the pressure fluctuation. Steady-state models neglect the effect of fluid inertia, but that is not a conservative estimate. In some cases, the effect of fluid inertia may be greater than the fluid/well-bore compressibility, and pressure fluctuation is underestimated with steady-state models. Fluid inertia causes the transient pressure to fluctuate after the pipe stops moving.

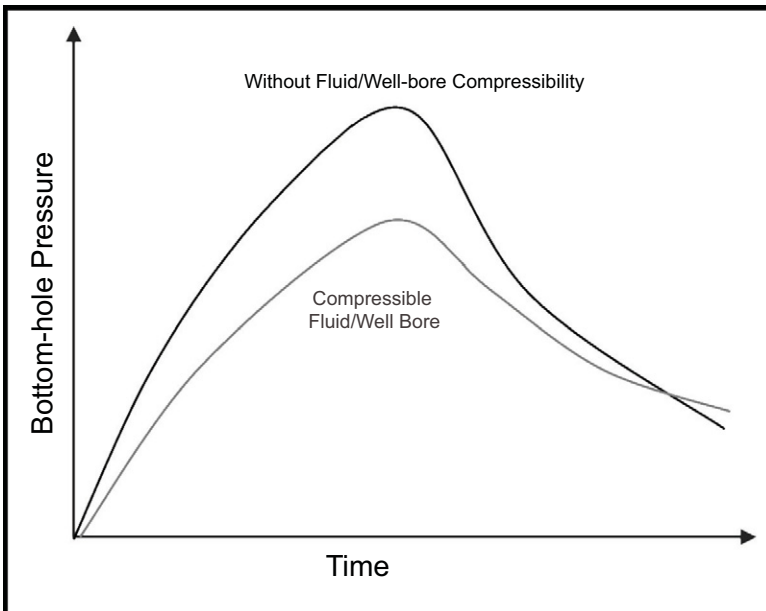


Figure 2.12 Compressibility of the drilling fluid and formation dampens the bottom-hole pressure change while moving the pipe. (Courtesy of Lal, 1983.)

- *Pipe distance off the bottom of the hole* affects the pressure fluctuation. When the pipe is on the bottom, maximum pressure fluctuation occurs. Figure 2.13 illustrates the effect of pipe location in the well bore on the transient pressure as a function of time.
- *Drilling bit and nozzle* restrict fluid flow in the well bore and increase the magnitude of pressure fluctuation. When an NRV is used at the bit, pipe movement creates a piston effect and increases the magnitude of the pressure fluctuation significantly.
- *Pipe elasticity and acceleration of the pipe* have the least effect on the pressure fluctuation. Pressure fluctuation changes the force exerted to the pipe, which because of the elasticity of the pipe, yields to a change in the length of pipe. Pipe elasticity acts against pressure and dampens pressure fluctuation. Acceleration of the pipe also affects the pipe length and the rate of change of transient phenomena. In most cases, acceleration of the pipe does not have a considerable effect on the maximum pressure change in the annulus. Pipe elasticity and acceleration of the pipe do not affect the results for shallow wells. However, they need to be considered for deep wells.

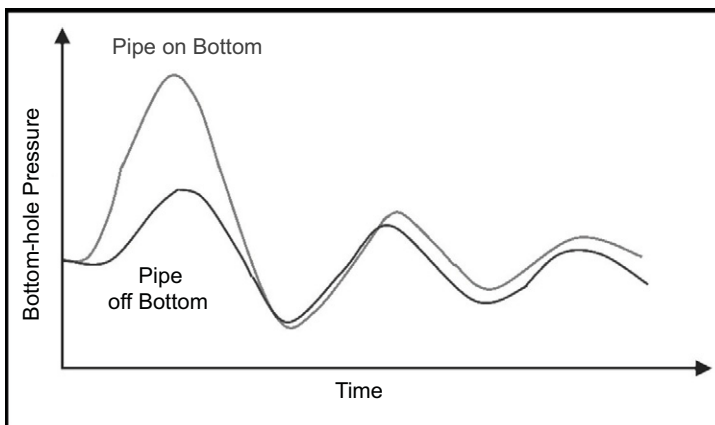


Figure 2.13 The effect of pipe movement with an off-bottom pipe.
(Courtesy of Lal, 1983.)

2.7.2 Estimating Pressure Surge and Swab

Several methods are available to estimate the pressure fluctuation caused by pipe movement. Lapeyrouse (2002) proposes steady-state models with the assumption of power-law fluid to estimate the maximum pressure fluctuation caused by pipe movement. In this method, drilling fluid properties and maximum fluid velocity are calculated to estimate maximum pressure fluctuation.

The mud properties are

$$n = 3.32 \log \left(\frac{R_{600}}{R_{300}} \right) \quad (2.13)$$

$$K = \frac{R_{300}}{511^n} \quad (2.14)$$

The maximum velocity of the drilling fluid, for open-ended pipe, is

$$v_m = \left[0.675 + \frac{1.5(d_p^2 - d_i^2)}{d_b^2 - d_p^2 + d_i^2} \right] v_p \quad (2.15)$$

For a closed-ended pipe, it is

$$v_m = \left[0.675 + \frac{1.5d_p^2}{d_b^2 - d_p^2} \right] v_p \quad (2.16)$$

Estimating pressure fluctuation yields

$$P_{ms} = \left(\frac{144v_m}{d_b - d_p} \times \frac{2n+1}{3n} \right)^n \times \frac{KL}{300(d_b - d_p)} \quad (2.17)$$

where

d_i = inside diameter of pipe, in.

d_b = hole diameter, in.

d_p = outside diameter of pipe, in.

p_{ms} = maximum surge/swab pressure, psi

v_m = maximum velocity of drilling fluid, ft/sec

v_p = maximum velocity of pipe, ft/sec

The bottom-hole pressure while running the pipe into the hole is the sum of the hydrostatic pressure and P_{ms} . When pulling the pipe out of the hole, P_{ms} is subtracted from hydrostatic pressure of drilling fluid.

Example 2.2

Calculate equivalent mud weight at the bottom-hole pressure while running the drill string into the hole. Consider both open-ended and closed-ended pipe.

$$R_{600} = 70.$$

$$R_{300} = 45.$$

Mud weight = 14 ppg.

Hole size = 8 in.

The drill pipe is as follows:

$$\text{OD} = 5.5 \text{ in.}$$

$$\text{ID} = 4.67 \text{ in.}$$

$$\text{Length} = 12,000 \text{ ft.}$$

$$\text{Pipe speed} = 2.5 \text{ ft/sec.}$$

Solution to Example 2.2

$$n = 3.32 \log \left(\frac{70}{45} \right) = 0.6371$$

$$K = \frac{45}{511^{0.6371}} = 0.847$$

For the open-ended pipe,

$$v_m = 2.5 \left[0.675 + \frac{1.5(5.5^2 - 4.67^2)}{8.625^2 - 5.5^2 + 4.67^2} \right]$$

$$v_m = 2.17 \text{ ft/sec}$$

$$P_{ms} = \left(\frac{144 \times 2.17}{8.625 - 5.5} \times \frac{2 \times 0.6371 + 1}{3 \times 0.6371} \right)^{0.6371} \times \frac{0.847 \times 12,000}{300(8.625 - 5.5)}$$

$$P_{ms} = 227 \text{ psi}$$

$$\text{ECD} = 14 + \frac{227}{0.052 \times 12,000} = 14.37 \text{ ppg}$$

For a closed-ended pipe,

$$v_m = 2.5 \left[0.675 + \frac{1.5 \times 5.5^2}{8.625^2 - 5.5^2} \right]$$

$$v_m = 4.26 \text{ ft/sec}$$

$$P_{ms} = \left(\frac{144v_m}{d_b - d_p} \times \frac{2n+1}{3n} \right)^n \times \frac{KL}{300(d_b - d_p)}$$

$$P_{ms} = 350 \text{ psi}$$

$$\text{ECD} = 14 + \frac{350}{0.052 \times 12,000} = 14.56 \text{ ppg}$$

Questions

1. What are the lower limits of well-bore pressure?
2. To consider the U-tube effect, calculate the volume of drilling fluid drained on the seafloor during a connection while drilling riserless. Water depth is 7500 ft with a seawater density of 8.7 ppg. The density of drilling fluid is 13.2 ppg, and the internal diameter of the drill pipe is 4.276 in.
3. Use API Recommended Practice 13D (2003) to calculate ECD at the casing seat and bottom of the hole for the given well geometry. Also calculate stand-pipe pressure while circulating. The geometry is
 Mud weight = 15.3 ppg.
 Circulation rate = 450 gpm.
 Hole size = 8.5 in.
 TVD = 14,500 ft.
 Casing seat = 12,400 ft.
 Casing ID = 9.5 in.

Drill pipe:

$$\text{OD} = 5 \text{ in.}$$

$$\text{ID} = 4.276 \text{ in.}$$

$$L = 13,750 \text{ ft.}$$

Drill collar:

$$\text{OD} = 6.5 \text{ in.}$$

$$\text{ID} = 3.5 \text{ in.}$$

$$\text{Nozzles} = 3 \times 20.$$

The relevant rotational viscometer readings are as follows:

$$R_3 = 7 \text{ (at 3 rpm).}$$

$$R_{100} = 8 \text{ (at 100 rpm).}$$

$$R_{300} = 43 \text{ (at 300 rpm).}$$

$$R_{600} = 70 \text{ (at 600 rpm).}$$

4. With a very small window between well-bore stability and fracture pressure, list four ways that it might be possible to drill through this zone.
5. What is well-bore ballooning? How do you tell it is happening?
6. Calculate equivalent mud weight at the bottom-hole pressure while running the drill string out of the hole. Consider both open-ended and closed-ended pipe.

$$R_{600} = 90.$$

$$R_{300} = 55.$$

$$\text{Mud weight} = 15 \text{ ppg.}$$

$$\text{Hole size} = 7.5 \text{ in.}$$

Drill pipe:

$$\text{OD} = 4.5 \text{ in.}$$

$$\text{ID} = 3.826 \text{ in.}$$

$$\text{Length} = 15,000 \text{ ft.}$$

$$\text{Pipe speed} = 3.0 \text{ ft/sec.}$$

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Answers

1. The lower limits of well-bore pressure are pore pressure and well-bore stability.
2. Here, 45.4 bbl of mud would be discharged to the seafloor when the pump stops and the drill pipe is allowed to completely U-tube.

3. Pressure drops in the different sections of the well are:
 - Surface to casing seat = 177 psi.
 - Casing seat to the top of collars = 30 psi.
 - Pressure drop across drill collars = 61 psi.
 - Pressure drop through nozzles = 158 psi.
 - Pressure drop inside the drill collars = 158 psi.
 - Pressure drop inside the drill pipes = 1178 psi.
 - ECD at the casing seat = 15.58 ppg.
 - ECD at the bottom of the hole = 15.66 ppg.
 - Stand-pipe pressure = 1941 psi.
4. The RMR system does not utilize a “typical marine riser.” The drill string above the seafloor is exposed to the open sea. The RMR system has the return pump located at the seafloor, whereas the CMP system can place the return pump at any location on the marine riser between the seafloor and the surface. The CMP allows the riser mud level to be adjusted to control the bottom-hole pressure. With a very small window between well-bore stability and fracture pressure, here are ways that it might be possible to drill through this zone. You were to list at least four choices.
 - a. Use a drilling fluid with the lowest possible ECD.
 - b. Change the azimuth of a directional hole to modify bore-hole stress.
 - c. Change the well-bore geometry.
 - d. Impress surface choke pressure on the annulus of the well.
 - e. Change the pumping rate to increase or decrease the circulating friction pressure.
 - f. Run a liner or extra string of casing.
5. Plastic formation takes some drilling fluid when circulating (or with pipe movement) and will return it when the pressure is released. The effect is similar to a leak-off test. This is noticeable when the pumps are turned off for a connection or trip. The well will flow a small stream that initially appears to be the start of a well kick. Within a half hour or more, it will be

evident that the flow is not increasing or actually decreasing and it can be concluded that this is well-bore ballooning and not the start of a well kick.

6. This case is swab pressure and P_{ms} should be subtracted from mud density.

Open-ended pipe: ECD = 14.43 ppg

Closed-ended pipe: ECD = 14.13 ppg

CHAPTER THREE

Constant Bottom-Hole Pressure with Pressure as a Primary Control

Paul Fredericks, At Balance Americas, LLC

About This Chapter

Drilling techniques do not always fit in the neat little box of a book chapter. Dealing with the organization of MPD techniques, it is practical to break them out based on the emphasis given to their process. In this case, while pressure is described as the primary control for the Dynamic Annular Pressure Control system, it is not proposed or suggested that it is the only control or, at some time, the primary control.

This chapter discusses the system and equipment for control of the constant bottom-hole pressure technique used by At Balance Americas, LLC, along with the planning and training necessary to make the drilling operation safe and efficient.

3.1 Introduction

A useful drilling technology is one that solves a real-world problem in a cost-effective manner with the least impact on other elements of the drilling system. Unlike underbalanced drilling technology, which completely replaces many conventional elements of the drilling system, managed pressure drilling technology connects to and enhances the capability of existing conventional elements. The capability of the drilling fluid and the circulation system, two basic elements that every drilling method uses to control bottom-hole pressure, is enhanced by MPD techniques. However, as a field ages with production, pore pressure, well-bore stability, and the fracture gradient can change to the point where more dynamic control is required.

Of the many different technologies and processes required to drill a well, none is more central to a successful drilling operation than those that control BHP. Geology and in-situ pressure determine the boundaries within which drilling must regulate the BHP. Regardless of the geology and pressure with which drilling must contend, a drilling system's primary tasks, such as transporting the cuttings, preventing influx and losses, and keeping the drill pipe free, the hole open, and the well on target and budget, are the same. Those tasks do not change as a field ages, they just get harder to accomplish.

The collection of pressure control methods referred to as *managed pressure drilling* complements the basic elements by (1) adding more control to the BHP while drilling, (2) extending control over BHP to operational phases when the rig pumps are off, (3) improving well-bore stability, (4) maintaining well control and safety, and (5) bringing into reach productive prospects too expensive to drill otherwise.

A number of methods are covered by the umbrella of managed pressure drilling:

- Constant bottom-hole pressure (CBHP).
- Pressurized mud cap drilling.
- Continuous circulation.
- Dual-gradient drilling.

- Riserless drilling.
- ECD reduction.

These methods differ in significant ways and not all are universally applicable in all fields. The technology presented and discussed in this chapter is used to provide only constant bottom-hole pressure.

3.2 Pressure Control

Generally, the MPD method known as *constant bottom-hole pressure* refers to a process whereby the annular pressure in a well is held constant or near constant at a specific depth, with the rig mud pumps on or off. In this context, *constant* means maintaining BHP within a window bounded by an upper and lower pressure limit (Figure 3.1). The difference between these limits is also known as the *margin*.

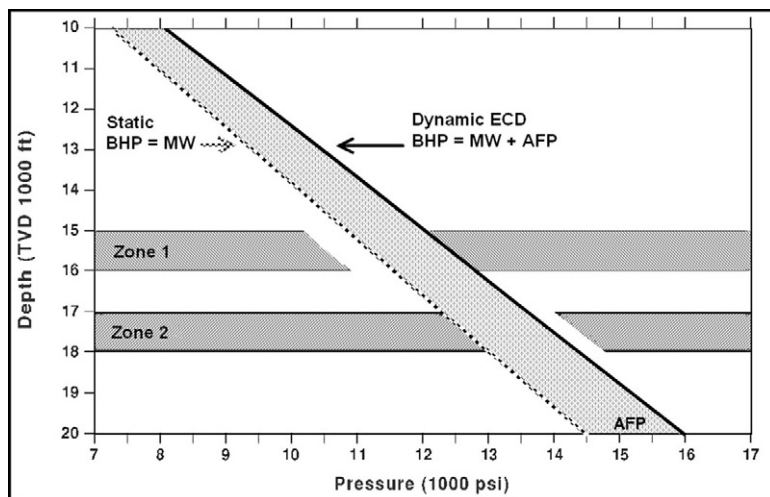


Figure 3.1 A pressure window defined on the low side by the pore pressure in Zone 2 and on the high side by the fracture gradient in Zone 1. Also, the typical situation that drilling encounters when the dynamic ECD gets too large to continue drilling past Zone 2, because in Zone 1, the ECD is equal to the fracture gradient.

On the low side, the margin is normally bounded by pore pressure, P_p , and well-bore stability, P_{wbs} , whereas on the high side, it can be bounded by differential sticking, P_{ds} , lost circulation, P_{ls} , and fracture pressure, P_f . In general, these pressures may be loosely related in the following way:

$$P_p < P_{wbs} < \text{BHP} < P_{ds} \leq P_{ls} \leq P_f \quad (3.1)$$

To understand the limits presented in Eq. 3.1 and the role they play in pressure control consider the simple but fundamental pressure equation:

$$\text{BHP}_{\text{Dynamic}} = P_{\text{Static}} + P_{\text{AFP}} \quad (3.2a)$$

where

P_{Static} = the hydrostatic pressure exerted by the drilling fluid
when the rig pumps are off

P_{AFP} = the annulus frictional pressure (AFP) created by the circulating drilling fluid

Equation 3.2a applies when the rig mud pumps are on and mud is circulating. The term $\text{BHP}_{\text{Dynamic}}$ is also referred to as the *equivalent circulating density* (ECD) and sometimes as *equivalent mud weight* (EMW) or *mud weight equivalent*. Normally, when an equivalent mud weight is used, the units of pressure are in pounds per gallon or specific gravity, SG.

When the pumps are off or when circulation stops, $P_{\text{AFP}} = 0$ and Eq. 3.2a becomes

$$\text{BHP}_{\text{Dynamic}} = P_{\text{Static}} \quad (3.2b)$$

Equations 3.2a and 3.2b represent dynamic and static BHP in an open circulation system (Figure 3.2). In an open system, the drilling fluid flows out of the wellhead through surface piping open to atmospheric pressure. In a closed circulation system, the drilling fluid flows out of the wellhead under pressure.

For most drilling operations pore pressure, P_p , represents the lower boundary for the BHP and the minimum that drilling maintains to avoid influx and kicks. However, in many fields, the minimum pressure boundary for well control is dictated by well-bore

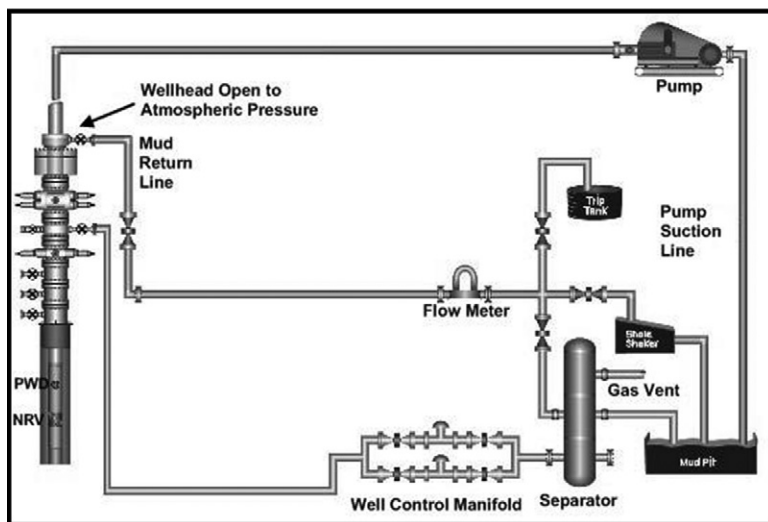


Figure 3.2 Open circulation system. Mud returns to the surface and flows out of the well through piping open to atmospheric pressure. There is no back pressure.

stability not pore pressure. Well-bore stability tends to be a more complex pressure phenomenon than pore pressure, because it is a function of the magnitude and direction of the maximum horizontal stress ($\sigma_{\max}$), well orientation relative to $\sigma_{\max}$, well inclination, drilling fluid rheology, and in particular its density, pore pressure, rock porosity, and permeability, as well as pump rate, rotary speed, and rate of penetration.

Generally, $P_{\text{wbs}} > P_p$; and depending on the field, the difference can be as small as 0.2–0.5 ppg (0.002–0.006 gm/cm³) EMW to as much as 2.5–3.0 ppg (0.3–0.36 gm/cm³). As the drilling fluid circulates, the additional P_{AFP} reduces the margin of safety with the upper limits: P_{ds} , P_{ls} , and P_{fg} (pressure fracture gradient). This is a particularly challenging situation in depleted fields with reduced fracture gradients and fields with fractured carbonates.

The risk of well-bore instability is heightened by the open system itself. Consider that, over time, a circulating drilling fluid charges an annular volume of rock near the borehole with ECD pressure. The depth of charging is limited by the permeability and porosity

of the rock itself and the degree to which the drilling fluid plugs the porosity channels at the borehole wall. When circulation stops, the charged volume relaxes and BHP reverts to BHP_{Static} , which is lower than the pressure of the charged rock. This cycle of charging and relaxing occurs every time the mud pumps are started and stopped. It stresses the rock, induces well-bore fatigue, and ultimately leads to tensile failure.

In an open system, the only way to maintain ECD at $BHP_{Dynamic}$ while the rig pumps are off is through the use of a continuous circulation system, which is beyond the scope of this chapter. The inability to maintain a constant bottom-hole pressure in an open system limits drilling to control pressure with P_{Static} and P_{AFP} .

Unlike an open circulation system, in which the drilling fluid flows out of the well under atmospheric pressure, a closed circulation system seals off the wellhead and applies surface back pressure to the fluid in the annulus by restricting its flow through a choke manifold (Figure 3.3).

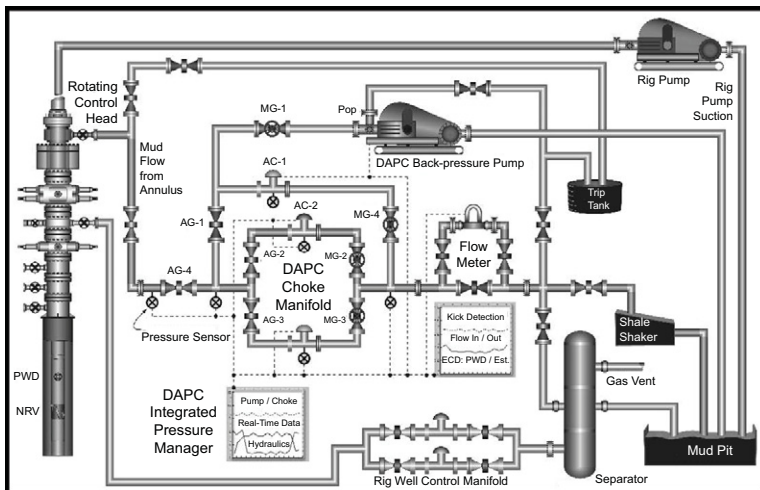


Figure 3.3 Closed circulation system. Mud returns to the surface under pressure and flows through a choke manifold designed to control the back pressure and maintain a constant BHP when the rig pumps are off.

In a closed circulation system, when the rig pumps are on, the fundamental pressure equation is

$$\text{BHP}_{\text{Dynamic}} = P_{\text{Static}} + P_{\text{AFP}} + P_{\text{bp}} \quad (3.3a)$$

where P_{Static} and P_{AFP} are the same as in Eq. 3.2a and P_{bp} is the surface back pressure applied to the annulus by pressure control equipment connected to the wellhead. Equation 3.3a applies when the rig mud pumps are on and mud is circulating.

Under static conditions when the rig pumps are off, $P_{\text{AFP}} = 0$ and Eq. 3.3a becomes

$$\text{BHP}_{\text{Dynamic}} = P_{\text{Static}} + P_{\text{bp}} \quad (3.3b)$$

In a closed system, the back pressure term, P_{bp} , is always present during a connection and, depending on the application, while drilling. It is through control of the back pressure that the BHP can be maintained at a constant value from dynamic to static conditions, that is, from pumps-on to pumps-off. However, not all constant bottom-hole pressure applications require the dynamic and static BHP to be equal, just as long as they are both within the limits defined by Eq. 3.1.

An inherent risk of an open system that is mitigated by closed-system back-pressure control is well-bore instability induced by the repeated pressure charging and relaxing associated with pumps-on and pumps-off. In a closed system, when the rig pumps stop, the choke manifold is closed to increase the back pressure, P_{bp} , and compensate for the loss of P_{AFP} . In that way, the $\text{BHP}_{\text{Dynamic}}$ and $\text{BHP}_{\text{Static}}$ remain constant and within the limits set by Eq. 3.1.

3.3 Constant-BHP Choke Systems

Closed-system back-pressure control expands an operator's ability to control the BHP by expanding the ability to manage P_{Static} and P_{AFP} and by giving the additional ability to manage P_{bp} .

All MPD systems that provide constant BHP rely on a rotating control device (RCD) (Figure 3.4) as the primary pressure seal. The RCD is mounted on the wellhead below the drill floor and above



Figure 3.4 The HOLD 2500 rotating control device. (Courtesy of Smith International, Inc.)

the annular blowout preventer (Figure 3.5). The piping and instrumentation drawing in Figure 3.3 shows the location of the RCD and typical piping connections.

Managed pressure drilling systems designed to maintain constant BHP manage the annulus back pressure with a fit-for-purpose choke manifold connected to the RCD. However, in some applications, operators use the rig's well-control choke manifold to manage back pressure but not necessarily for constant BHP.

Choke systems for constant BHP differ from each other in

1. Control method.
2. Integration of choke control and hydraulics model.
3. Use of pressure-while-drilling (PWD) data to calibrate the hydraulics model.
4. Real-time capability and speed of the hydraulics model.
5. The ability to create back pressure with an independent back-pressure pump.



Figure 3.5 The HOLD 2500 rotating control head being installed in a wellhead on a deepwater offshore platform in the Gulf of Mexico. (Courtesy of Smith International, Inc.)

In addition, choke control can be manual, automated, or semi-automated, which is a mix of both.

3.4 Operational Considerations

Getting ready for managed pressure drilling with a closed circulation system requires a number of additional planning phases and tasks. Typically, MPD planning starts with one or a series of orientation meetings to review and plan actions and contingencies for every phase of the operation. Some of these planning actions are concurrent but, without a doubt, none should be overlooked.

Like every other type of drilling operation, managed pressure drilling carries its own set of risks. However, drilling a well under pressure raises the importance of safety and reliability to new levels. For that reason, planning and preparation typically start earlier in MPD operations than in conventional drilling operations.

Early on, drilling engineers or their third-party representatives together with the service providers begin a review of

- Risks at every stage of the MPD operation.
- Plans to mitigate those risks.
- Contingency action plans in the event preventative actions fail.

Typically, MPD operations start soon after the selection of services and before the well spud date. It begins with a series of orientation meetings in which the operator presents the

- Casing design.
- Mud program.
- Hydraulics analyses.
- Well plan.
- Pressure profiles through the applicable hole sections.
- Rig equipment specifications and layout.
- Rig and well data acquisition and communication.
- Drilling tools specifications.
- MPD system and RCD specifications and functionality.
- Health, safety, and environment case reviews.
- Hazard identification (HAZID) and hazard operability (HAZOP).
- Preliminary operational procedures.
- Crew training.
- Rig site and operational support.
- Regulatory issues.
- Rig site objectives, schedule, results, and actions.

Planning and preparation for MPD operations should include a review of the

1. Value proposition—quantify the value the MPD will deliver.
The value of the MPD includes a number of strong economic drivers, such as
 - Drill time or cost savings.

- Increased access to reserves in depleted reservoirs or smaller reservoirs that may be uneconomic for conventional drilling.
 - The number of wells that cannot be drilled conventionally but can be with MPD.
 - Improved safety.
2. MPD equipment and rig compatibility:
 - Identify the optimum location on the rig for the MPD equipment, keeping in mind its safety specifications and the deck load ratings of offshore rigs.
 - Quantify the amount and size of the piping needed to interconnect the MPD and rig equipment, the pressure drop in the piping, the number of “elbow” connections (right-angle turns), and its pressure rating.
 - Identify the modifications to be made to the rig equipment to connect the MPD.
 - Ensure sufficient space is available between the top of the BOP stack and the rig floor for installation of the RCD.
 3. Drilling hydraulics, an essential part of drilling and well design also, critical for MPD applications:
 - The drilling pressure window must be defined based on the pore pressure/fracture-gradient (PP/FG) plot.
 - Establish the minimum BHPs for well control and bore-hole stability and the maximum BHP for lost circulation.
 - Model the casing and drill-pipe geometries with the planned mud properties at optimum drilling parameters.
 - Define the EMW of the AFP while circulating at planned drilling rates.
 - Evaluate alternate mud weight scenarios with MPD to reduce the static mud weight and the ECD at the modeled flow rates, rotary speed, and penetration rate.
 - Designate the pressure reference or set point to be held while drilling and during connections.
 - Define the tolerance window around the set-point pressure that establishes the minimum and maximum allowable fluctuations.

4. Personnel training:

- Plan and conduct HAZID and HAZOP workshops to review the MPD system and specify the potential risks.
- Identify the corresponding mitigation or response actions for each risk element.
- Categorize the HAZID results into drilling, connection, and tripping events and their relative risk (e.g., underpressure or overpressure).
- Conduct training in at least two stages, classroom and on site, to prepare the rig and service crews.
- In the classroom, introduce MPD concepts, specify the value and cause for action, provide details of the MPD system components, and review the contingency plans defined in the HAZOP workshops.
- At the well site, provide pretour presentations and walk through the equipment installation and operation.
- Last, it is highly recommended to make a dedicated pipe trip in casing and prior to drilling into an open hole to test the MPD system functionality and practice contingency plan actions.

5. Procedures—develop procedures for every major phase of the particular MPD operations, which should include:

- Testing and commissioning of the primary pressure control system after arrival at the point of embarkation and prior to shipment to the well.
- Placement, rig-up, piping layout and connection, and power connection.
- Formal well site testing and commissioning, involving specific operating scenarios and contingencies.
- Making the transition from pumps-on while drilling to pumps-off to make a connection and back.
- Describe the method for tripping out of the well before reaching total depth (TD).
- Any task that affects the pressure regime of the well, such as picking up drill pipe off the bottom, reducing the pump

stroke rate, stopping the mud pumps suddenly, trips in and out of the hole, plugged drill string or nozzles, mud pump washout, change in mud properties, and increasing rate of penetration, which induces more cuttings in the annulus.

This list is meant to convey only an overview of the critical tasks involved with MPD operational planning, preparation, and execution.

3.5 DAPC System Description

The Dynamic Annular Pressure Control™ (DAPC™) system is an example of an automated back-pressure control system. It is designed to manage the BHP while drilling with the rig pumps on or off.

Figure 3.3 shows the main DAPC system components on a typical MPD operation:

- Choke manifold.
- Back-pressure pump.
- Integrated pressure manager.
- Hydraulics model.

Flowmeters have become an important addition to MPD operations and most systems are designed to use it to detect kicks. Usually, only one flowmeter is installed, on the low pressure side of the manifold, to measure the flow out of the well. Most MPD systems calculate flow into the well from the pump stroke rate. By comparing flow-out to flow-in, calculated from the rig pump rate, the system can deliver early kick detection warnings.

Overall, the DAPC system is designed with features that allow it to handle a number of contingencies by itself.

3.5.1 DAPC Choke Manifold

Figure 3.6 shows a an offshore choke manifold and Figure 3.7 an onshore manifold. Offshore conditions are governed by a number of safety regulations and logistical considerations that dictate a more robust manifold design. The manifold shown in Figure 3.6 is

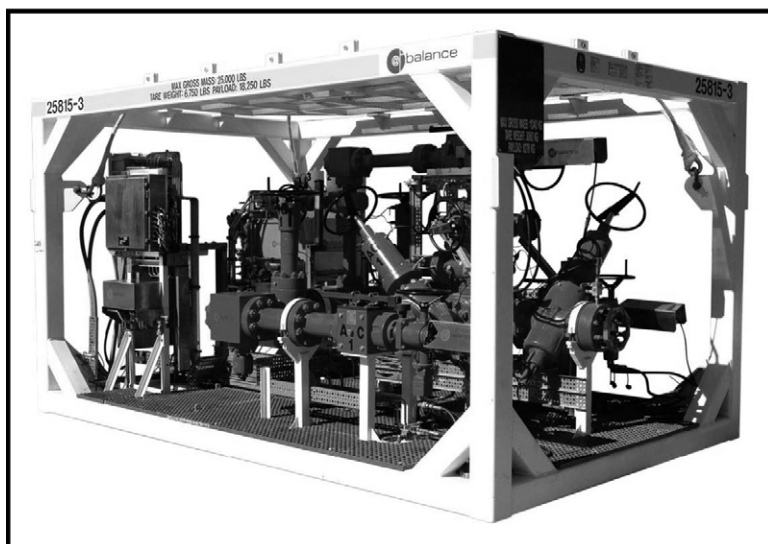


Figure 3.6 DAPC automated choke manifold designed for offshore conditions. It is mounted on a DNV-certified crash frame and conforms to DNV 2.7-1/T3, Class 1/Division 2/Zone 2. It contains three chokes, two main chokes and one auxiliary choke, and is rated to 5000 psi.

designed to satisfy offshore regulations around the world, whereas the manifold in Figure 3.7 is meant for the more mobile onshore market.

The offshore manifold contains three chokes, two side-by-side redundant main chokes (AC-2 and AC-3 in Figure 3.3) and an auxiliary choke (AC-1 in Figure 3.3). The onshore manifold is built with only two main chokes because there is no need for the auxiliary choke on a typical land MPD job. During normal drilling operations, mud circulates through one of the main chokes, although it is possible to circulate through both if higher flow rates are needed.

Ideally, when the chokes are fully open there will be little or no back pressure, but that depends on the piping specification, the mud, and the piping layout. When the chokes are fully closed, there is no flow; and under normal conditions, the chokes are closed only

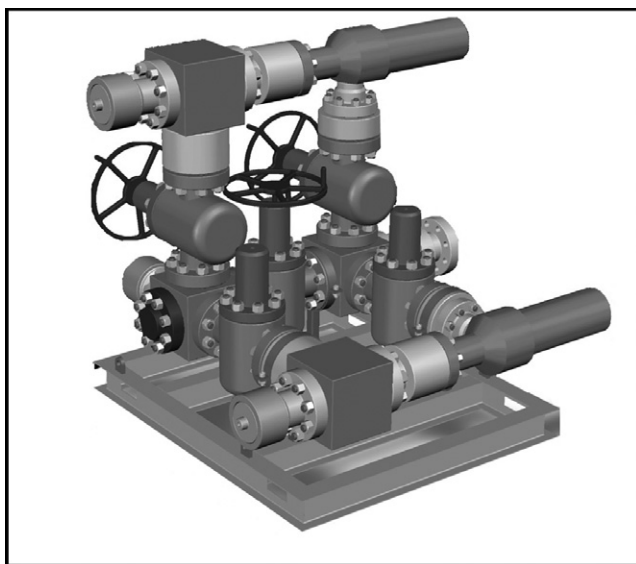


Figure 3.7 DAPC automated choke manifold designed for onshore operations. It is mounted on an open skid, designed for easy handling on land rigs and overland transport. It contains two main chokes and is rated to 5000 psi.

when there is no flow. By manipulating the choke position between the open and closed positions, the system can vary the back pressure for the given application.

An automated system like the DAPC calculates the back pressure required to maintain the BHP at the set point and moves the choke to the required position to achieve it. By monitoring the pressure around the clock, it can respond to changing conditions and continuously adjust the choke to hold the back pressure and the BHP within the prescribed operating window.

One of the many benefits of an automated pressure-control system is that, in the event the active choke becomes nonresponsive or jammed, the system will immediately redirect flow through the backup choke; hence, no human intervention is required. This eliminates the potential for lost circulation. However, at any time,

the MPD operator can override the system and manually switch chokes for maintenance or testing purposes.

Most closed circulation drilling systems include a way to relieve pressure in the event the system becomes jammed. Pressure relief is typically controlled via a separate valve that is installed close to the wellhead between the rotating control head and the manifold (see Figure 3.3). A feature of an automated system like the DAPC is that the auxiliary choke can be used as a backup pressure-relief valve (PRV) or as the primary PRV.

Pressure stability is essential in pressure drilling. That means eliminating, or at the very least minimizing, any type of anomaly that may cause the BHP to spike outside its safe operating window. Pressure spikes are most commonly caused by the driller, when adjusting the rig pump rate, which is done every time a connection is made. In preparation for any MPD job, it is important to inform the drillers of the pressure window and the primary role they play in managing the pressure through smooth rig pump operation (outlined previously under “personnel training” and “procedures”).

The auxiliary choke used by the DAPC system was an early solution to compensate for spikes induced during the transition from drilling with the rig pumps on to a connection with the rig pumps off and back. It was used to stabilize the pressure during connections.

When a connection is about to be made, several things have to occur in the MPD system to avoid spikes in the BHP. First, the driller picks the drill bit up off the bottom and starts to reduce the pump rate. With the DAPC system, the controller turns on the back-pressure pump and starts to close the active choke in response to changes in the rig pump rate. With a manual or a semi-automated MPD system, a system operator has to manually close the choke. In the DAPC system, the controller continuously manages the choke position during the pressure transition from rig pump on to off, to keep the back pressure and the BHP stable and within the prescribed window. Pressure sensors installed throughout the manifold provide the data the system need to continuously control the pressure. In a manual system, a choke operator has to visually read the pressure gauges and make adjustments as the pressure changes. Any

distraction, fatigue, or doubt about the readings affect this person's ability to operate the choke and hold the pressure constant.

The primary goal during the transition from pumps-on to pumps-off and back is to maintain the BHP within the prescribed pressure window. The smaller the window, the more difficult it is for a human operator to hold the pressure constant.

3.5.2 DAPC Back-Pressure Pump

Back-pressure MPD systems that utilize choke manifolds differ from each other by, among other things, the extent of their ability to control and create back pressure. As long as a sufficient volume of mud flows through a partially open choke, there will be back pressure. When the mud flow rate slows down, the choke has to close to hold the same level of back pressure. If the flow of mud stops completely, then the choke has to close completely to trap the remaining back pressure. The amount of back pressure trapped depends on how quickly an operator or a control system can respond to the flow-rate changes.

However, no matter how fast a choke can be closed by human or machine it is unlikely that it will ever be fast enough to respond to an immediate loss of pressure caused by sudden pump failure or human error. Lost back pressure stays lost until flow from the well resumes or is provided by another source. Unfortunately, loss of back pressure means loss of BHP control and possibly loss of well control in a tight margin.

One solution is to equip the back-pressure MPD system with its own on-demand pump and safety technology to control it. That solution extends the dynamic range of a system's control and its ability to actively create back pressure as and when needed. The DAPC system uses a dedicated back-pressure pump (Figure 3.8) to do just that.

The back-pressure pump is a low-volume, triplex pump connected to the choke manifold (Figure 3.9) and automatically controlled by the system. Whenever the pressure manager senses that the flow from the well is insufficient to maintain the required back pressure (e.g., during connections and trips), it automatically turns on the back-pressure pump.

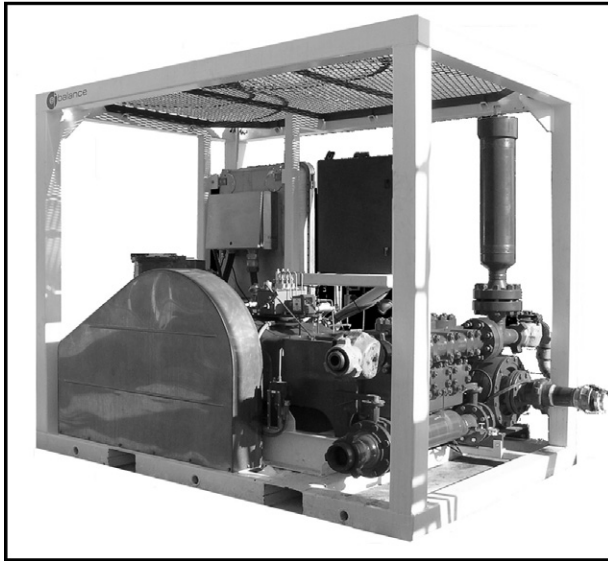


Figure 3.8 A DAPC back-pressure pump mounted on a DNV-certified crash frame, conforming to DNV 2.7/T3, Zone 2.

3.5.3 Integrated Pressure Manager

In addition to managing pressure, MPD operations must also manage the risks to the health and safety of people and the environment. Because of the inherent health, safety, and environmental risks involved in managed pressure drilling, the DAPC system was designed as a completely integrated pressure control system.

Each component of the DAPC system is connected by way of a high-speed network, including the real-time hydraulics model and system controller. This feature is not shared by all automated systems. *Automation* is used somewhat loosely to refer to choke automation. It is important to know that it is possible for an MPD system to have an automated choke without having an integrated hydraulics model driving the controller. A completely automated system like the DAPC (Figure 3.10) is one in which control is driven by an online hydraulics model.

An automated pressure management control system must be able to respond to changing conditions as fast as possible—speed is

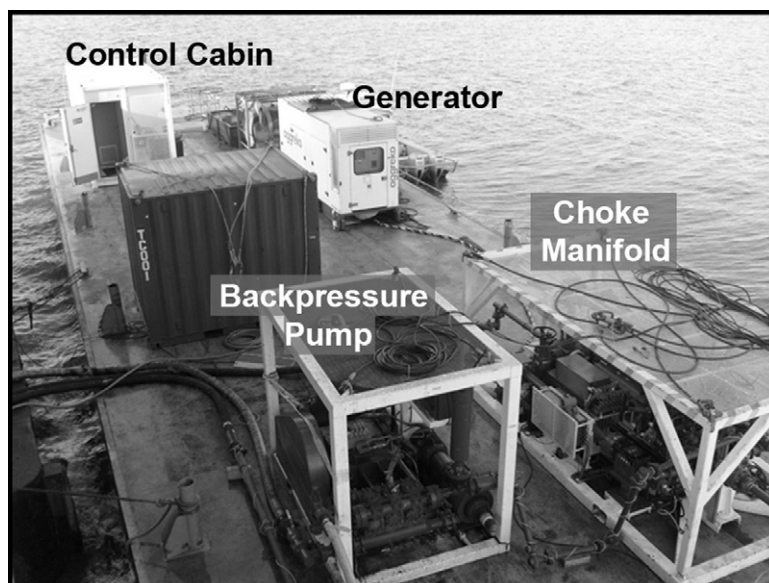


Figure 3.9 A DAPC automated pressure-control system rigged up on an inland barge in Louisiana state waters. Mud flow from the DAPC back-pressure pump (skid on the left) goes through the pipe to the auxiliary choke leg in the DAPC manifold (white skid unit on the right). Return mud flow from the well goes into the main choke leg in the manifold.

essential—without relying on human intervention. This is especially critical when the pressure window is on the order of a percent or less of the absolute BHP value. That makes choke positioning a time-critical operation.

In the DAPC system, the pressure manager control software resides on a programmable logic controller (PLC; Figure 3.11) designed to collect pressure measurements and feedback from the choke-limit switches, monitor and adjust choke positions, and monitor and control the back-pressure pump. As a system, the software and PLC hardware are linked via a high-speed network bus to the manifold and pump, data acquisition network, and human/machine interface. In addition, over the same high-speed link, the pressure manager communicates with a real-time hydraulics model that calculates the BHP

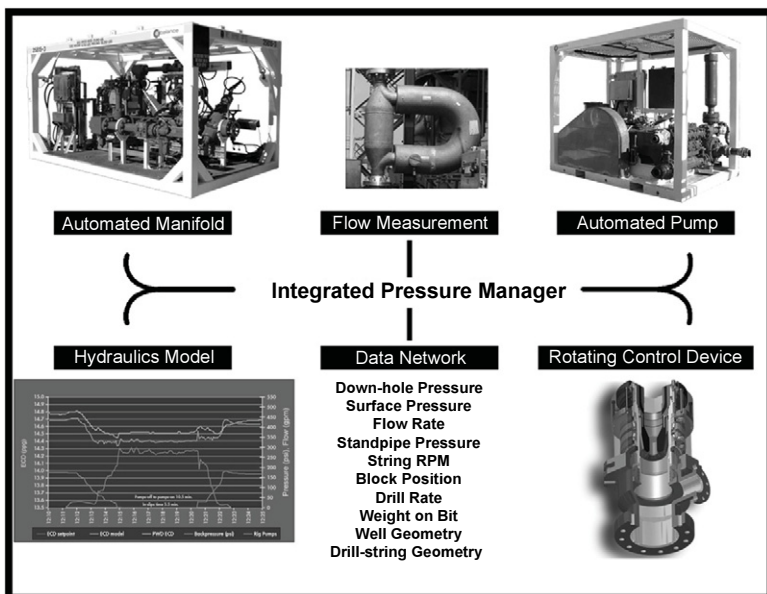


Figure 3.10 The interconnections among the major components of an integrated pressure control system. In a completely automated system, the hydraulics model is connected by way of a high-speed network to the safety-critical process controller. In a semi-automated system, a human operator enters model data into the controller, which adds unacceptable delay into the time-critical choke control.

value, which the pressure manager uses along with the reference set point for control.

Maintaining the BHP at the set point at all times is the pressure manager's most important task. The set point is the pressure control point designated at a specific depth in the well. It is typically designated at either the casing point or the bit, and it guides the pressure manager's every action. If the BHP deviates from the set point, the pressure manager automatically corrects the back pressure by adjusting the choke position.

In normal drilling mode, the DAPC hydraulics model provides frequent updates to the pressure manager so it can respond to pressure changes in a timely manner and maintain a constant BHP. It calculates the BHP once a second and calibrates itself every time it



Figure 3.11 An open PLC on the DAPC choke manifold. The PLC contains the safety-critical control technology that manages the manifold's operation.

receives updated pressure data from a down-hole pressure tool. As the update rate from the down-hole tool increases, so does model accuracy.

Most hydraulic models in use today for MPD are single-phase models; that is, their accuracy is limited to liquid-phase drilling fluids.

3.5.4 Case Study

A good example that highlights the practical drilling benefits of automated pressure control can be seen from a well drilled offshore in the Bunga Kekwa field located in the South China Sea. In the ongoing development of this field, drilling has had to contend with costly problems associated with pressure depletion. Over time,

depletion caused a decline in both the reservoir and fracture pressures, narrowing the limits between stability and lost circulation. Conventional efforts to manage the margin resulted in partial to total losses, cuttings loading, and slow drilling, making it difficult to reach TD and stay on budget. Unable to cost-effectively eliminate these problems with conventional methods, the drilling operator turned to an automated-pressure drilling solution.

Conventional pressure management in the Bunga Kekwa wells adds to the drill time through its use of high mud weights for well-bore stability, low flow rates to minimize ECD, high solids to control coal seam losses, high inclinations, and controlled drill rates for cuttings removal. Constant attention is required to manage annular loading, which at times caused the ECD to climb 2 ppg above static and dynamic BHP to exceed the fracture limits.

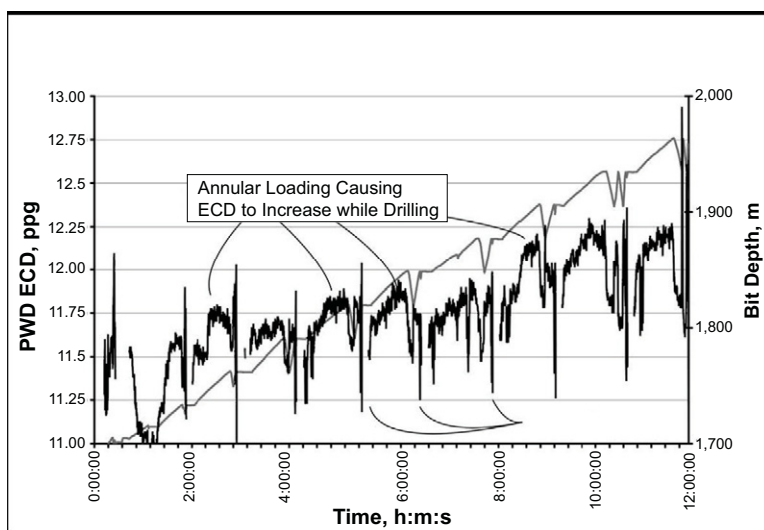


Figure 3.12 Pressure recorded down the hole while drilling in the upper section of an offshore well in the South China Sea without the DAPC system. Annular loading increased due to a buildup of drilling solids. The loading caused the ECD to increase during each stand and steadily rise throughout the section.

Hole cleaning and ECD reduction involved nonproductive drilling and nondrilling time to ream and circulate, on average 30–60 min or more, before every connection; control drill at rates one-half to one-third of normal; back ream; short trip; and circulate bottoms up—all of which add up to an opportunity for MPD to reduce drill time and cost.

The operator elected to use the automated DAPC system to hold pressure within a narrow window and reduce the static mud weight by over 1 ppg, eliminate LCM solids, increase flow rate, and reduce the ECD to improve overall drill time.

Figures 3.12 and 3.13 are plots of the actual down-hole pressure as measured by a down-hole pressure tool in the 8.5-in. hole section of one of the wells drilled with the DAPC system. Figure 3.12 is the PWD data acquired in the upper part of the 8.5-in. hole, where the DAPC system was not used; and Figure 3.13 is a plot of

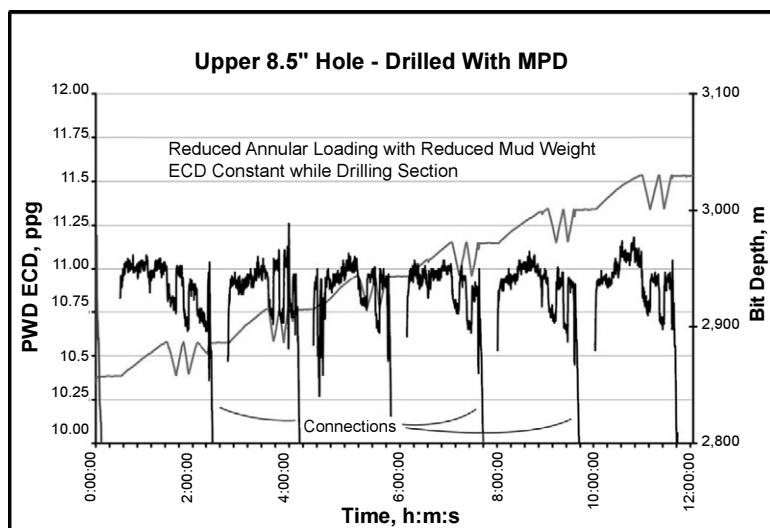


Figure 3.13 Pressure recorded down the hole while drilling in the lower section of the same offshore well in the South China Sea but with the DAPC system. Annular loading was minimal, and the ECD was held stable and flat throughout the section.

the data acquired from the lower hole section, where the DAPC system was used.

It is evident from the pressure in the upper section (Figure 3.12) that there is an increase in annular loading due to poor hole cleaning. As a consequence, the ECD increases while drilling each stand of pipe and throughout the section. This inability to control ECD leads to partial and total losses in previously drilled wells.

In the hole section drilled with the DAPC system, the pressure recorded by the PWD tool (Figure 3.13) shows little increase in ECD while drilling each stand and no increase over the section. This is visible proof that the annular loading seen in the upper section is eliminated, and that is made possible by using the DAPC system, which allows the operator to reduce the mud weight to a level not possible with conventional drilling.

Questions

1. What is the primary control for constant bottom-hole pressure with this system?
2. How is the bottom-hole pressure held constant?
3. In a constant bottom-hole pressure system, BHP is to be maintained within a window bounded by an upper and lower pressure limit. What important factors control each boundary?
4. In an open circulation system, how is the pressure control affected when (a) pumps are on and (b) pumps are off?
5. Is maintaining the ECD at BHP_{Dynamic} , while the rig pumps are off, the same in both open and closed systems?
6. What key factors should be considered and reviewed in planning and preparation for MPD?
7. Why is a constant pump ramp speed important?
8. With this system, if the pumps were shut off quickly, how would the system compensate?
9. What is the DAPC system?

10. In the case study, how did the DAPC system affect the annular-pressure loading?
11. What conditions could cause pressure spikes at the bottom hole?

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Answers

1. This system uses pressure measurement as the normal primary control. However, as in all constant BHP systems, the primary system may take second place to some other measurement, if conditions warrant it.
2. Bottom-hole pressure is held constant by application of choke pressure on the annulus.
3. On the low side, the margin is normally bounded by pore pressure and well-bore stability, whereas on the high side, it can be bounded by differential sticking, lost circulation, and fracture pressure. For most drilling operations, pore pressure represents the lower boundary for BHP and the minimum that

drilling maintains to avoid influx and kicks. However, in some fields, the minimum pressure boundary for well control is dictated by well-bore stability not pore pressure.

4. When the pumps are on, based on Eqs. 3.2a and 3.2b, the dynamic bottom-hole pressure is the sum of the hydrostatic pressure exerted by the drilling fluid when the rig pumps are off and the annulus frictional pressure created by the circulating drilling fluid. When the pumps are off or when circulation stops, $P_{AFP} = 0$.
5. In an open system, there is no practical way to maintain the ECD at $BHP_{Dynamic}$ while the rig pumps are off. The closed circulation system seals off the wellhead and applies surface back pressure to the fluid in the annulus by early choke closure or by restricting its flow through a choke manifold.
6. Value proposition, MPD equipment and rig compatibility, drilling hydraulics, personnel training, and procedures are the key factors in planning preparation for MPD.
7. Pump ramp speed, or a step change in pump rate as the pump is turned on or off, is important because the annulus pressure imposed on the system needs to balance the change in the equivalent circulating density (P_{AFP}) to maintain a constant bottom-hole pressure.
8. If the pumps were shut off abruptly, the “back-pressure” pump would feed into the annulus ahead of the choke to help maintain a constant bottom-hole pressure.
9. The Dynamic Annular Pressure Control (DAPC) system is an automated back-pressure control system. It is designed to manage the BHP while drilling with the rig pumps on or off. The main DAPC system components on a typical MPD operation include a choke manifold, back-pressure pump, integrated pressure manager, and hydraulics model.
10. Before using the DAPC system, annular loading increased due to a buildup of drilling solids and the loading caused the ECD to increase during each stand with a steady rise through the

section. The DAPC system held the loading to its minimum and the ECD was held stable and flat throughout the section.

11. Pressure spikes are generally caused by the driller's action and could be caused by turning the pump on, turning the pump off, or pipe movement up or down.

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CHAPTER FOUR

MPD with Flow Measurement as the Primary Control

Erdem Catak, *Secure Drilling, LP*

About This Chapter

Not all of the material about this system falls into the neat box represented by this chapter. Field operations are an adaptive process; and the primary control, in this case flow measurement, may be subordinated or run parallel to some other measurement as conditions warrant. This chapter presents the ideas behind the Secure Drilling™ system, how it works, and examples of results.

4.1 Description of the Process

Secure Drilling is a managed pressure drilling technology specifically designed to enable drilling of high-pressure, complex wells while enhancing safety, improving drilling efficiency, and reducing the costs of the well. It collects and analyzes drilling data (including pressures) and flow rates into and out of the well bore to manage the well-bore pressures effectively. The Secure Drilling system, using the patented Micro-Flux Control (MFC) technology, provides a revolutionary change in the accuracy of measurement and

analysis of flow and pressure data, using proprietary algorithms to identify minute down-hole influxes and losses on a real-time basis. Santos, Leuchtenberg, and Shayegi (2003) describe MFC as a method where drilling is conducted with the well closed (i.e., using a rotating control device) and the return flow routed through a pressure/flow-control device (i.e., a choke) and a precision flow measuring device.

The system provides automated flow or pressure control using proprietary software algorithms and real-time trending and comparison of well-bore pressures and flows into and out of the well bore. It allows for adjustments in pressure or flow and, thus, down-hole conditions while drilling, accomplished through precise control of choke position. The system allows drilling decisions to be made based on actual data versus predicted down-hole environments, providing real-time monitoring of well-bore parameters. The Secure Drilling system is based on real-time, measured data and uses typical drilling data inputs, including:

- Flow rates in and out of the well bore.
- Injection pressure (also called *standpipe pressure*).
- Surface back pressure.
- Choke position.
- Drilling fluid density (mud weight).
- Optionally, down-hole sensors, such as bottom-hole pressure.

Safety is enhanced significantly because the well is drilled closed, with the pressures being positively controlled by an automated choke, while all conventional well-control equipment, certification, and training remain the same. Further, when the driller closes the blowout preventor at any time, it completely bypasses the automated system. From this point, conventional and standard practices apply.

4.2 Special Drilling Equipment

Unlike conventional drilling, where the fluid return is open to the atmosphere, the system uses a rotating control device to keep the

well closed and, subsequently, the fluid flows through an automated choke manifold. The unique feature of this technology is the capability to measure return flow using a flowmeter installed inline with the chokes. The drilling setup requires minimal additions to the existing rig equipment: a rotating control device, a secure drilling manifold, and a real-time data acquisition and control system.

4.2.1 Circulation Path

Figure 4.1 shows a typical circulation path, including the additional equipment required. The manifold includes a gut line that can be used for operations when debris from the well is expected, such as after drilling the casing shoe. Depending on the procedure employed by the operator, the fluid returning through the manifold

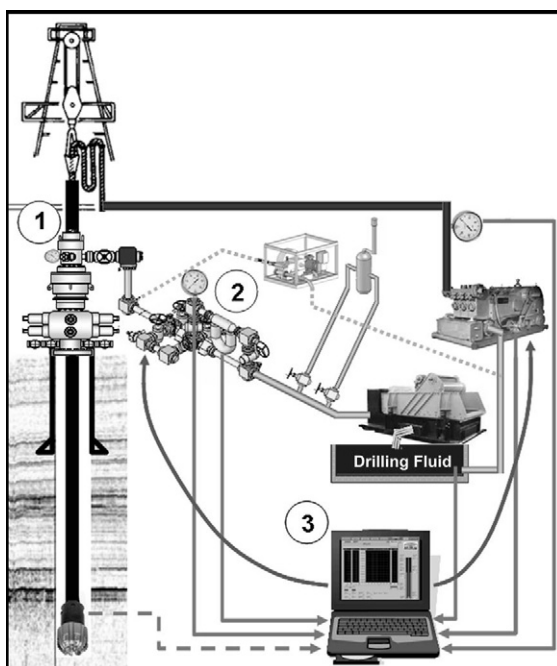


Figure 4.1 Typical circulation path of (1) the rotating control device, (2) Secure Drilling manifold, and (3) real-time data acquisition.

can go straight to the shale shakers or, if the gas ratio becomes higher than a predetermined limit, the returns can be diverted to the mud gas separator.

4.2.2 Rotating Control Device

As the well needs to be closed at all times, a rotating control device (RCD) diverts the flow to the drilling manifold. The selection of the size and pressure rating of the RCD depends on the required surface pressures and available spacing between the BOP stack and rig floor.

4.2.3 Drilling Manifold

The manifold is installed on the return line, downstream of the RCD. To have as small a footprint as possible, all required equipment is installed on a compact, integrated manifold. It is composed of the following primary components:

- Two specialized, severe service drilling chokes with actuators.
- A mass flowmeter.
- An intelligent control unit.

The manifold includes two specialized, severe service drilling chokes with actuators. One specialized drilling choke is for continuous use and the second provides redundancy. The choke applies the back pressure to the annulus as required by the control system. If the active choke requires maintenance during drilling operations, flow can be directed to the second choke. Currently, the chokes are dressed with 3-in. or 2-in. trim; however, depending on the anticipated flow rates, drilling fluid properties, and drilling parameters, other trim sizes can be used without difficulty. This gives flexibility to the equipment for optimization on the hole section being drilled.

The Coriolis-type mass flowmeter (see Chapter 9 for more information) is installed on the manifold downstream of the drilling chokes. The meter provides four major properties of the return fluid: mass flow rate, volumetric flow rate, density (mud weight), and temperature.

Since the flowmeter is installed in the closed fluid loop before the shale shakers or mud gas separator, these parameters are direct measurements and include the cuttings and gas associated with the drilling process but not the surface effects of fluid handling or processing.

The intelligent control unit (ICU) is the brain of the Secure Drilling system. It is installed in an explosion-proof housing on the manifold. It is composed of power supply and distribution, signal conditioning and data acquisition, and a control system. All the critical data acquisition processes, control algorithms, and remote control functions are operated from the ICU.

4.3 Real-Time Data Acquisition and Control

Real-time data acquisition and control incorporate the human/machine interface, including the Secure Drilling operator's panel, driller's panel, and remote panels. The system is controlled remotely by the driller and Secure Drilling operational personnel through the driller's panel and the operator's panel, which houses the user interface. The panels are connected to the ICU, located on the manifold skid, via fiber-optic cables. In addition to the panels available to the driller and the operator, additional devices can receive the basic information for monitoring purposes and be located as required virtually anywhere on site. Satellite transmission to different office locations is an available option and may be installed at the rig with advance planning. Figure 4.2 shows the drilling manifold in use on a well drilled in Brazil.

4.4 Drilling Applications

Depending on the pressure profile throughout the well bore and complexity of the drilling program, there are two approaches for MPD applications: the standard approach and the special approach.

4.4.1 Standard Approach

The standard approach is appropriate when the well is planned with a static mud weight that provides slightly overbalanced well-bore

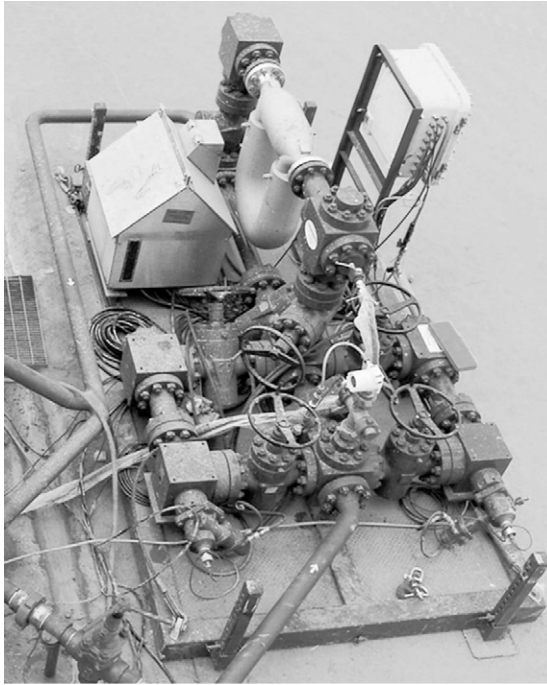


Figure 4.2 A Secure Drilling manifold in use.

pressures. In this standard application, the conventional well design does not require significant modification. The chokes are fully open while drilling and ready to apply back pressure when and as needed to exert control if an influx is detected. The goal is to allow the crew to safely reduce the mud weight to remain closer to the pore pressure, by having enhanced kick detection and control capability at all times. By using a mud weight close to the pore pressure, many drilling problems, such as differentially stuck pipe, mud losses, and low drilling rate of penetration, are reduced or eliminated.

Requirements

The requirements and features of the standard process are

- The well is statically overbalanced; conventional drilling can be restored at any time desired.

- It can be used on any well with no change to the well design.
- Very little training is required (30 minutes at the well site).
- All standard operational procedures remain the same, that is, drilling, connections, tripping, casing, cementing, and logging.
- All safety and well-control procedures and certification requirements remain the same.

Capabilities of the Standard Approach

The principal capabilities of the standard package are

- Automatic kick and loss detection.
- Automatic kick control, circulation of influx, and kill mud displacement using the driller's method.
- Actual pore and fracture pressure determination, in case kicks or losses are detected.
- High-pressure and high-temperature fingerprinting.
- Ballooning identification and quantification.
- Management of the mud weight program—confirmation of a statically underbalanced condition during connections and the real need to increase mud weight.
- Reduction of total influx volume (kick tolerance calculation with extension of section length and, consequently, reduction of casing strings).
- Identification of the swabbing of a kick while back reaming.
- Surge/swab pressure monitoring and its consequences.
- More accurate interpretation of the leak-off and casing tests.
- Performance of formation integrity tests while drilling.
- Identification of normal drilling problems:
 - Pipe washout.
 - Mud pump problems, such as loss of efficiency, leakage, or pump cavitation.
 - Distinguishing a down-hole influx from gas (or air) at the surface.

- Connection gas with relative volumetric qualification.
- Induced fractures.

Methods

Influx or a loss is detected by the system based on comparisons of actual and predicted flows and pressures and trend recognition. The system also indicates the estimated pore or fracture pressures.

Automatic Loss Detection

The Coriolis flowmeter, along with the ICU, has the ability to detect mud losses at a very early stage, typically before the total lost volume reaches 0.5 bbl. The system displays a message, alerting for the potential problem, allowing fast actions to be employed to prevent the losses from becoming total. With this accuracy, it is practical to measure the severity of the loss from the discrepancy observed from the flows being measured. A total loss of circulation condition also is spotted very early, with the flow-out showing a sudden drop to zero, allowing the driller to take the necessary steps to prevent a well-control event caused by loss of the hydrostatic column.

Influx Analysis

A possible influx is first noted when the flow-out deviates from the flow-in, but until the system actually confirms that it is indeed an influx, the operation proceeds normally. Detection of the influx occurs with less than 0.5 bbl of the kick taken into the well bore. Once the system confirms an influx is occurring, an alert is displayed. To reduce the number of false alarms, the system uses a series of confirmation parameters and trend analysis when looking at flows and pressures to ascertain that an influx is indeed occurring.

After the influx has been detected, no change in pump rate is needed. The choke automatically closes to increase the back pressure at the surface and stop the influx. After the influx is controlled, when the bottom-hole pressure equals the formation pressure and the flow from the formation to the well bore ceases, the total influx volume is usually less than 2 bbl.

After an influx has been detected and controlled, the annular surface pressure is increased by a predetermined pressure safety mar-

gin. Then, the influx is automatically circulated out of the well bore following the driller's method of well control. When the influx is close to the surface, the system displays a warning message on the screen to warn the driller that the influx is approaching the surface. There is no need to take any action; this is just to make the personnel aware that the influx is close to the surface.

Kill-Weight Mud Circulation

The last step is to circulate the kill-weight mud. This may also be controlled automatically by the system. When the operator verifies that the influx is out of the well, the system displays the recommended kill mud weight and asks the operator to enter the existing mud weight available for the kill operation. While the kill mud is being circulated down the drill string, the software displays a message indicating that the kill mud is falling in the drill string. The system keeps the back pressure constant in this mode. After the kill mud starts rising up the annulus, a message is displayed on the screen, informing the driller about the situation. The standpipe pressure is kept constant until the kill mud is circulated all the way to the surface.

Trend Analysis and Event Recognition

The system analyzes the trends during regular operations to differentiate losses and kicks from regular well behavior. Some formations are prone to ballooning. The well continues to flow for a time after the pumps are shut down. The system can differentiate a gas kick from a normal ballooning or thermal expansion condition.

Events that can be identified include:

- Surface versus down-hole events: kicks versus temperature expansion or gas cutting.
- Underbalance due to insufficient bottom-hole pressure, that is, static underbalance versus dynamic underbalance.
- Ballooning formations.
- Pump problems: plugged nozzle, washed-out nozzle, parted drill pipe, and the like.

Observing precise flow signatures allows differentiating conditions during the operations. Typically, an *influx* is detected by the increase in return flow. However, the increasing flow may also be the result of *gas expansion* at the surface. The main difference between a down-hole influx and surface gas expansion is that surface gas causes a gas cut in the mud and reduces the return fluid density, while a gas influx does not.

Under a dynamically overbalanced but statically underbalanced condition, the hydrostatic pressure is not enough to compensate the formation pressure after the mud pumps have been stopped, and the well kicks. The situation is detected by the system using a comparison between expected and actual flow-out. If a normal condition is present, the expected flow-out decreases continuously. However, if the well is statically underbalanced, the flow-out might initially start to decrease then increase as soon as the well becomes underbalanced. Return flow measurement may be used for determining the degree of underbalance as well. The return flow signature changes depending on the degree of underbalance.

It is very common in HPHT wells for the well to flow when the pumps are stopped for a certain period of time. This is often confused with a kick, and a long time is spent making sure the flow is occurring due to normal conditions. Well-bore *ballooning* is another event that shows similar behavior, with the fluid “lost” while drilling, then this volume returns when circulation is stopped. These conditions can be identified with trend analysis. In a ballooning environment, although the pump is turned off, the flow-out continues, however, with a decreasing trend, until the pressures in the well and the formation are equal. The Secure Drilling system was successfully used for identifying ballooning, and details were presented by Santos et al. (2007b) and Sonnemann et al. (2007).

A *washout* is typically identified by a reduction in standpipe pressure with no change in flow. Due to the accuracy of data acquired by the system and the easiness of interpreting the visual charts, a drill-pipe washout can easily be detected and at very early stages. Pump problems fall into the same category and are subject to very early detection.

4.4.2 Special Systems Approach

The special package is appropriate when the well is planned with a static mud weight that does not provide an adequate overbalanced well-bore pressure against pore pressure or well-bore stability. In this application, the chokes are engaged to provide a constant back pressure on the annulus. The goal is to maintain a constant bottom-hole pressure (CBHP) while reducing the mud density enough to keep the ECD below the fracture pressure. By keeping the bottom-hole pressure under control, the drilling operation avoids the lost circulation/kick cycle and hole instability.

With this method, whenever normal circulation is interrupted, back pressure is applied at the surface to compensate the loss of annular friction. The special system automatically maintains a programmed or predetermined overbalance at all times while allowing use of the lighter mud weights, with the attendant benefits.

When employing the special package, more planning from the well design point of view is a necessity:

- Review all procedures, including safety and well control.
- HAZOP and HAZID are emphasized.
- More extensive crew training is required.

In operation, the system controls the back pressure at the surface by following a predetermined set point imposed by the user. The control of the choke is automatic, and it can follow any desired input method: manual input or automatic interface with a hydraulic model or other predictive tool.

Even though the special system can be used on virtually any well or rig, it has more obvious economical benefits in the following situations:

- Exploratory wells.
- Wells with a narrow mud weight window.
- High-pressure/high-temperature wells.
- Depleted fields, especially ones with pressure maintenance programs.

- Zones with rapid change in pore pressure regime.
- Areas known for a high incidence of kicks.
- Areas with high pore pressure and fracture pressure uncertainty.

Automatic Pressure Control

The Secure Drilling system provides automatic pressure control for the drilling operations. When the well is being drilled with surface back pressure for any reason (i.e., well-bore stability, predetermined constant bottom-hole pressure, reduced mud weight, etc.), the system automatically controls bottom-hole pressure at a set value.

Pressure Control during Connections

Pressure control during connections is employed when the well must be drilled with a constant pressure at a point of interest within the well. When the mud pumps are turned off for connection, the frictional pressure in the annulus is lost and pressure in the well bore decreases. In this case, the loss of friction is compensated by adding back pressure at the surface. Unlike conventional drilling, where the driller turns off the mud pumps instantaneously, the driller must follow a predetermined number of steps and bring the pumps down following a schedule. Meanwhile, the Secure Drilling system monitors the pump speed and simultaneously adjusts the surface back pressure automatically to maintain well-bore pressure within a tolerance band. Pressure control during connections typically has two common applications. First, it is used for compensating the loss of overbalance down hole if a statically underbalanced mud weight is in use. Second, it is used for minimizing pressure changes in the open hole or at the point of interest where ballooning, fluid injectivity, or well-bore instability is the main concern.

Influx/Loss Monitoring while Drilling with Back Pressure

Flow monitoring during pressure control is essential to ensure well-bore integrity and influx mitigation. A constant bottom-hole pressure application may, and in most cases will, mitigate many drilling problems. On the other hand, the increased back pressure at the surface

will change the well-bore pressure profile and may lead to mud losses, if the fracture gradient of any of the formations is exceeded. Flow monitoring enhances the quality of the pressure control and ensures that the operation is carried safely within the drilling window.

Formation Integrity Test while Drilling

Leak-off tests or formation integrity tests are typically done only at the casing shoe after drilling a few feet into the formation. In most cases, the casing shoe is expected to be the weakest point in the open hole. However, due to complex geological settings and naturally existing fractures or unconsolidated formations in the open hole, sometimes mud losses, varying from seepage to total loss, are experienced at pressures below the LOT or FIT recorded at the casing shoe. Employing the automatic pressure control and flow monitoring capabilities of the system allows for dynamic leak-off tests while drilling with no nonproductive time. The back pressure is increased in steps while monitoring the flow in and out of the well bore. The operator may decide to carry the process all the way to the leak-off point or to test the open hole to a certain pressure. FIT while drilling, prior to a planned mud weight increase, is also useful to test the integrity of the formations to the proposed increased mud weight.

4.5 Case Histories

In early wells drilled with the system for Petrobras and Chevron, results confirmed the accuracy of the flow and pressure measurements, previously identified during tests at a research facility, with water- and oil-based drilling fluids. Figure 4.3 shows the main screen of the control system with an “Influx Detected” warning message and pressures after the influx is detected and controlled. Observe that the choke closed and pressures increased to bring the flow-out back to a normal condition, which is, for that particular case, equal to the flow-in.

Kick detection in oil-based mud (OBM) is provided just as accurately as in water-based mud (WBM). Kick detection in oil and

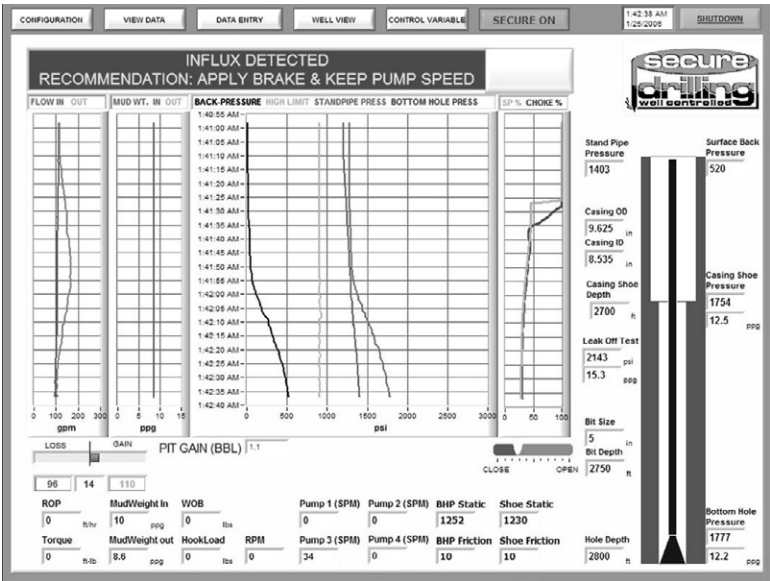


Figure 4.3 The main panel of the control system warns the detection of a fluid influx.

synthetic-based fluids has been a major concern for the industry for decades. Due to gas solubility in hydrocarbon-based drilling fluids, kick detection may be delayed, and the resulting well-control operations are difficult. Simulation results by Trancocean for Sidekick™ have shown that, with less than 1 bbl of gas influx, there is not much difference between the pit gain using WBM or OBM. As the Secure Drilling system detects influxes with less than 0.5 bbl, it is around two orders of magnitude better than conventional means. This explains the system’s ability to detect the influxes with the same accuracy and response in both OBM and WBM (Santos et al., 2007a).

The system’s ability to reveal a “micro flux” is clearly illustrated when the pipe is moving up or down and flow-out indicates a volume change as the tool joint passes through the rotating control device (Santos et al., 2007a).

The system demonstrated, during the first wells drilled, that the events are detected and identified earlier than by the conventional

rig equipment. These events were confirmed by mud logging results but with a significant delay. Early detection of events is necessary in avoiding NPT.

Avoiding conditions where the well has to be shut in numerous times by identifying and quantifying flow events and avoiding fishing a drill string because a washout was identified in its earliest stages are some of the advantages of the Micro-Flux system.

A direct comparison with down-hole pressure while drilling tools showed the surface data acquired by the Secure Drilling system are more accurate than the down-hole information collected by the down-hole pressure gauge. On one well, influxes were clearly detected when stopping the pumps for connections, indicating a statically underbalanced condition; and these events were used to manage the mud weight increase. Figure 4.4 shows an influx detected in real time when the pumps were off during a connection. Observe that the flow-out was reduced but then increased, which is

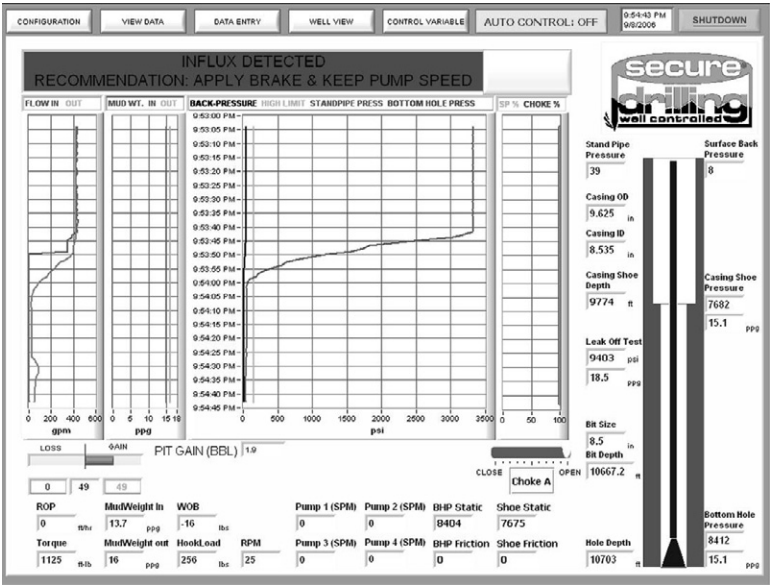


Figure 4.4 A kick is detected in real time with the pumps off.

not the normal behavior. After “bottoms up,” the gas arrived at surface and was confirmed by both the Secure Drilling and standard mud logging technique.

Questions

1. How does the Secure Drilling system control bottom-hole pressure during the operation?
2. List the Secure Drilling additions to the rig components.
3. What is the main concept behind the Secure Drilling system, enabling it to distinguish different well behavior?
4. What is the difference between the standard and special approach with the Secure Drilling system?
5. List wells for which the special approach to the Secure Drilling system may result in better economic advantages.
6. Explain FIT while drilling.

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Answers

1. The Secure Drilling system controls the bottom-hole pressure by precise manipulation of the choke position.
2. Secure drilling additions to the rig component are
 - a. Rotational control device.
 - b. Secure Drilling manifold.
 - c. Real-time data acquisition.
3. The ability to measure flow rate and detection of micro influxes in and out of the well enables the Secure Drilling system to distinguish different well behaviors.
4. The standard approach is applied when the hydrostatic pressure of the drilling fluid balances or exceeds the pore pressure, while the special approach is applied when the hydrostatic pressure of the drilling fluid is less than the pore pressure.
5. The special approach has more obvious economical benefits in the following situations:
 - a. Exploratory wells.
 - b. Wells with a narrow mud weight window.
 - c. High-pressure/high-temperature wells.
 - d. Depleted fields, especially ones with pressure maintenance programs.
 - e. Zones with rapid change in pore pressure regime.
 - f. Areas known for a high incidence of kicks.
 - g. Areas with high pore and fracture pressure uncertainty.

6. The back pressure is increased in steps while monitoring the flow-in and flow-out of the well bore. The operator may decide to carry the process all the way to the leak-off point or to test the open hole to a certain pressure. FIT while drilling prior to a planned mud weight increase is also useful to test the integrity of the formations to the proposed increased mud weight.

CHAPTER FIVE

Continuous Circulation System

Rod Vogel and Jim Brugman,
National Oilwell Varco

About This Chapter

This chapter describes the application and pipe handling, rig requirement, and operational safety with a continuous circulation system. Continuous circulation eliminates the bottom-hole pressure changes during connections. This system has the potential to increase the drilling efficiency in places where maintaining the annular friction pressure is the key to achieving the objectives of the operation. Like other MPD-directed systems, continuous circulation does not exist as an isolated system but involves pressures and volume changes as well as constant circulation. The National Oilwell Varco System described here is more equipment centered than other MPD operations.

5.1 Introduction

As confirmed by tests carried out by various operators, using the continuous circulation system (CCS) can significantly change the

way drilling operations are carried out when “difficult-to-drill” formations are encountered. Maintaining uninterrupted circulation while making connections in difficult-to-drill formations is now possible with all the associated benefits. With continuous circulation, a steady equivalent circulating density can be maintained. Moreover, the system minimizes the positive and negative pressure surges associated with making a connection under normal drilling conditions. This results in shorter total connection time, a more stable well bore with improved hole cleaning, and the elimination of connection gas kicks.

The CCS has proven to be a safe, reliable system that allows operators to successfully drill high-pressure/high-temperature wells and wells with narrow pore pressure/fracture pressure gradient windows, which were previously difficult to drill, time consuming, and expensive. It can also be used with closed-hole circulation drilling to drill reservoirs, where formation damage and impaired production can be reduced by maintaining continuous circulation and controlling the ECD overbalance. The system has proven to be safe and reliable to operate and has successfully achieved its programmed drilling objectives.

5.2 The System

As Calderoni et al. (2006a) report, the prototype CCS was developed by a joint industry project of six major European oil companies. It is a pressure chamber through which the drill string passes and that can form a seal on each side of the drill-pipe tool joint. This allows pressure inside and outside the drill string to be equalized by introducing drilling fluid at circulating pressure into the chamber between the seals. The connection is broken, and the pin is backed out and raised clear of the box before the pressure chamber is divided into two sections by a sealing device closing above the box. Pressure is then bled off in the upper section, allowing the pin connection to be removed.

At the same time, uninterrupted circulation is maintained along the side of the chamber and down the open tool joint box. To add a

new joint or stand of drill pipe connected to the top drive, it is run into the upper chamber, which seals around the pipe body and is filled with drilling fluid at circulating pressure from the circulating system. With pressure equalized, the dividing seal can be opened, the tool joint pin and box brought together, and the connection made up, with circulation redirected through the top drive into the drill string. When the pressure in the chamber is bled off, the seals are opened, and drilling can resume.

The makeup and breakout of the connection and the movement of the drill pipe into and out of the upper section are performed under circulating pressure conditions. At the top of the pressure chamber, a combination power tong and snubbing device are attached to control the pipe handling in the chamber.

5.3 Development

Using existing blowout preventer parts as its core, the prototype and ancillary equipment were constructed and tested in time for a field trial in July–August 2003 on a land rig drilling for BP in Oklahoma. The trial was a success, with the unit making 72 connections with 4½-in. drill pipe while drilling a 12¼-in. hole and circulating at between 2800 and 3000 psi. The drill pipe was inspected before and after the test, and no significant effects were found.

Following the successful field trial, commercial production started. A redesign was undertaken to reduce the size and weight, fully computerize the controls, and develop all the components needed to complete a system capable of handling drill pipe with an outside diameter in the range of 3½–5½ in.

The main CCS elements, as illustrated in Figure 5.1, comprise

- The main unit, which is shown in Figure 5.2. This unit is constructed from three 9-in.-bore, 5000-psi working pressure-rated BOP bodies. Pipe rams are located in the top, blind rams in the center, and inverted pipe rams in the bottom. A combination make/break power tong/pipe spinner and vertical snubber is attached to the top of the unit by hydraulic jacks.

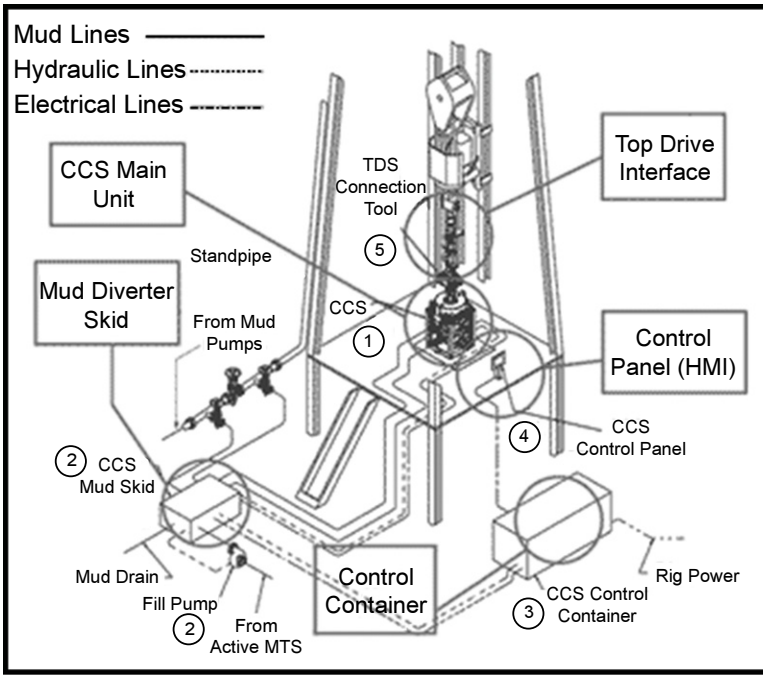


Figure 5.1 The main components of the CCS.

Drill-pipe slips are hydraulically operated and attached to the bottom of the main unit.

- The mud diverter unit (MDU), which is connected to the bypass manifold and located in the delivery line between the main rig mud pumps and the derrick standpipe. The MDU switches the flow of drilling fluid between the top drive and the CCS during the connection process.
- The top drive interface, which has three components:
 1. The top drive extension/wear sub (saver sub) is about 8 ft (2.5 m) long. The sub is locked to the bottom of the top drive and reaches inside the main unit to position the connection below the blind rams when drilling or running in. When pulling out with circulation, it picks up the open tool joint box inside the main unit.

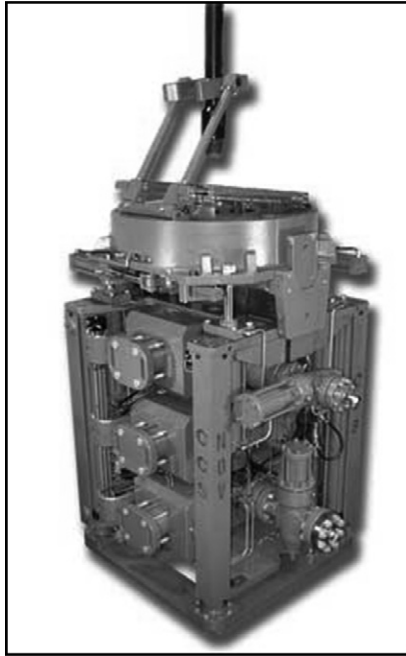


Figure 5.2 The main unit of the system, built from three BOP-style bodies.

2. The top drive connection tool (TDCT) is suspended below the top drive at the level of the saver-sub tool joint and makes or breaks the connection between the saver sub and a stand of drill pipe in the derrick.
 3. The dual-sided elevator (DSE) is suspended below the TDCT and picks up and handles drill-pipe stands in the derrick. The elevators can be opened on one side to latch around a stand as it is being pulled through the system at the rig floor level and opened on the opposite side by the derrickman to rack or pick up a stand in the derrick.
- Control panel human/machine interface (HMI), which is located at the driller's position; all system functions are controlled via a touch screen interface.
 - The control container, which contains the system's hydraulic power unit and the "black box recorder," which gathers and

stores data on the system's operation. This element provides Internet data transmission to link CCS to off-location and monitoring systems.

5.4 Control System

The controls are fully automated, enabling trained technical personnel to safely and efficiently operate the system. The system has built-in safety alarms, manual interlocks between activities, and the ability to reverse or undo steps in the operating procedures.

The operating system is controlled from a touch screen, or HMI. It is self-checking, but it can be interrupted at any stage, and the activity can be reversed by the operator. Most important of all, it is safe for all personnel involved. Calderoni et al. (2006a) discuss more details on the control system.

5.5 Applications

The system has been particularly effective when used to drill formations where making connections conventionally can be extremely difficult. This problem occurs where there is a narrow pore pressure/fracture pressure gradient window. If the static mud weight is sufficient to control the well, the additional friction pressure generated when circulating is often sufficient to exceed the formation fracture pressure gradient and create losses. Regaining circulation, by reducing the static mud weight and drilling ahead with the ECD, creates problems when circulation is interrupted to make a connection. The removal of the dynamic pressure component can be sufficient to induce flow and formation collapse, making connections difficult and time consuming.

Balanced pressure drilling is unique among managed pressure drilling techniques, because it maintains uninterrupted circulation during connections to establish a constant BHP regime while drilling ahead. This steady-state, circulating condition eliminates the transitory down-hole pressure effects experienced during conventional drill-pipe connections. In HPHT wells, these pressure surges can be

significant, causing well-bore ballooning when breaking circulation and fluid influx and formation collapse when the pumps are stopped. In these conditions, using the CCS results in improved hole conditions, faster total connection times (the elapsed time from stopping to restarting drilling), and less chance of stuck pipe.

When open annulus returns can no longer be sustained, drilling can continue, using the system in conjunction with rotating BOP equipment and annular pressure control. With closed-hole circulation drilling, the annular chokes are used to supplement the continuous circulation and control minor annular pressure fluctuations created by small influxes, losses, or temperature-related changes to mud density. In the event of major losses, drilling progress has been successfully maintained while continuing to pump fluid to the drill pipe and maintaining a mud cap in the annulus, with the annular injection of mud. The continuous movement of fluid keeps the drill string free in the hole.

Another potential application is high-angle or extended-reach drilling, where the potential hazards of high rotary torque and stuck pipe can be minimized by keeping the cuttings moving in the annulus, thereby reducing the buildup of cuttings “weirs” in the deviated hole section.

5.6 Operation

Flatern (2003) describes CCS as a pressure chamber sealed with a inverted BOP ram at the bottom and a BOP at the top. The tool joint is connected and disconnected in this chamber. Figure 5.3 illustrates CCS operation.

When the joint is in the chamber, upper and lower rams are closed to seal the chamber. Then, the chamber is pressurized and the connection is broken. The saver sub is raised up and down; the chamber is divided into two sections, an upper section with a separated stand and a lower chamber holding the drill string. Circulation is diverted to the lower chamber to maintain continuous circulation. The upper chamber is depressurized to allow conventional pipe handling.

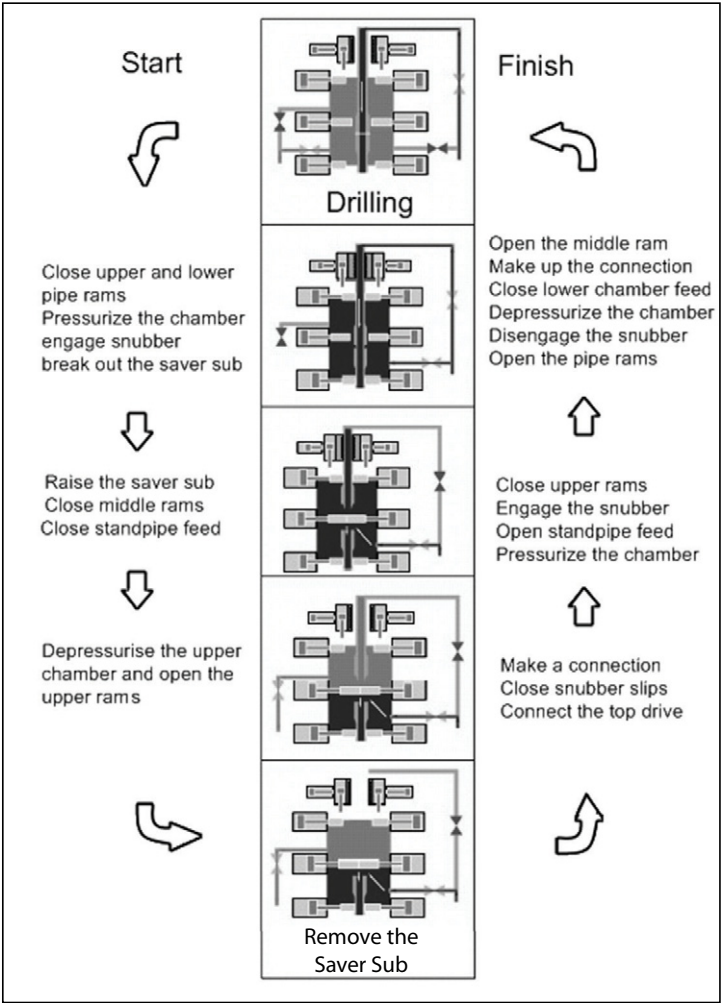


Figure 5.3 Connection procedure while drilling with CCS. (Courtesy of Flatern, 2003.)

When a new connection is made, the upper rams are closed and the upper chamber is pressurized to equalize the pressure across upper and lower chambers. Then, the blind rams are opened and connection is made. Simultaneously, circulation is diverted from the lower chamber to the top drive system to resume drilling.

5.7 Well Planning

It is advisable to plan drilling operations in advance, if intending to apply continuous circulation techniques, as all related drilling information must be considered to establish the drilling parameters required. If previous unsuccessful attempts to drill have been made, knowledge of the mud types and densities employed is important, as are pore pressure and fracture pressure data. Measurement-while-drilling, logging-while-drilling, (bottom-hole) pressure-while-drilling (MWD/LWD/PWD) tools can be used with continuous circulation and should be run to record real-time ECD measurements and other well data as drilling progresses. This allows adjustment of mud density and circulation rates with precision.

On completion of a hole section, before pulling the drill string, a trip program that controls the density of the replacement mud and a displacement program are needed to maintain a constant bottom-hole pressure.

If a liner is to be run, it can be circulated continuously and rotated after the liner hanger and running tool have been made up on the drill pipe.

The CCS can be used on any drilling unit big enough to accommodate the main unit on the rig floor and equipped with a top drive. This includes most modern mobile offshore drilling units, platform rigs, and most large land rigs. Before starting operations with the system, an inspection team from the service company needs to check the rig to determine the CCS equipment layout. The most important elements are for the provision of an electrical power supply, positioning of the HPU, and the layout of the control cables and hydraulic hoses.

The only structural modification required is the installation of mud bypass and MWD filter manifolds in the delivery line between the pumps and the derrick standpipe. This can be done at a time when regular drilling operations will not be interrupted. Since all the mud flow must pass through it before being diverted to either the standpipe or the main unit, the filter manifold must be upstream of the bypass manifold. To minimize exposure to personnel, the routing of the high-pressure mud circulation connection between

the MDU and the main unit on the rig floor must be carefully planned and the hose, or hard pipe, preinstalled, if possible.

The condition and type of top drive is important, as are the number and condition of the main mud pumps. Ideally, there should be three, because two pumps normally run continuously while drilling with uninterrupted circulation. A flexible mud storage system with sufficient capacity to change out, store, and treat the mud volume in the hole is advisable, as well as an efficient treatment system to maintain the required mud density in circulation.

When drilling with continuous circulation, a change in well-control practices is required and must be addressed prior to beginning drilling. Balanced pressure drilling (BPD) calls for a new approach to well-control planning; and it is necessary to rethink the well-control procedures to be applied. The reasons for drilling with uninterrupted circulation must be remembered, and dynamic well-control procedures must be put in place, with the rig crew trained and prepared to apply them.

If using an underbalanced mud column, circulation must be maintained, and the well must be controlled under dynamic conditions to maintain the ECD at the correct level. The normal procedure of stopping circulation, picking up off bottom, and closing the BOPs to take pressure buildup readings before increasing the mud weight and circulating out an influx cannot be done while drilling with continuous circulation. That practice leads to the loss of the BPD condition and a return to the loss/flow situation of normal drilling. Against this background, well-control procedures specific to the well and the rig employed need to be prepared and the crews trained in their application.

5.8 Records and Reporting

CCS is equipped with a reporting program to monitor the operation for maintenance and quality control purposes. The program produces a daily drilling report, which includes reports covering each connection made, any issues ensuing, ram seal usage, the maintenance record, and the spares situation. From these data, graphic

reports can be prepared for each stage of each connection sequence, as shown in Figure 5.4. This graph can be used to evaluate problems and difficulties of operation to specific stages of pipe handling in the chamber. Figure 5.5 illustrates the standpipe and lower chamber pressures at each stage. This figure demonstrates the sequence of pressurizing and depressurizing the chamber, number of connections, and total time required for pipe handling.

Another purpose of this open program is to provide real-time support and monitoring. In the case history in Section 5.9, the reporting program was monitored from the Houston technical center. The center is manned 24 hr/day and gathers data through an Internet connection to the system's "black box." Subject experts can be accessed at any time to consult on equipment malfunctions. In many cases, adjustments to operating programs can be made via the real-time connection. Every effort has been made to ensure the system's reliability and consistent operation, as well as for its associated equipment.

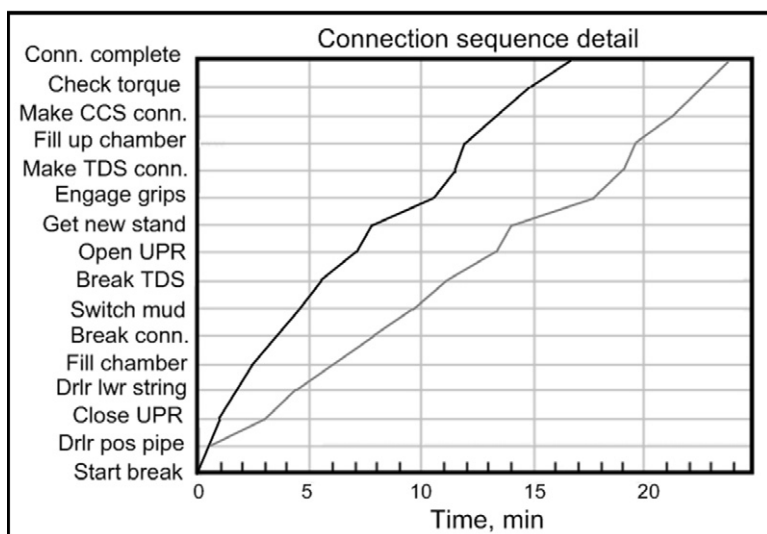


Figure 5.4 A graphic report can be prepared for each stage of each connection sequence.

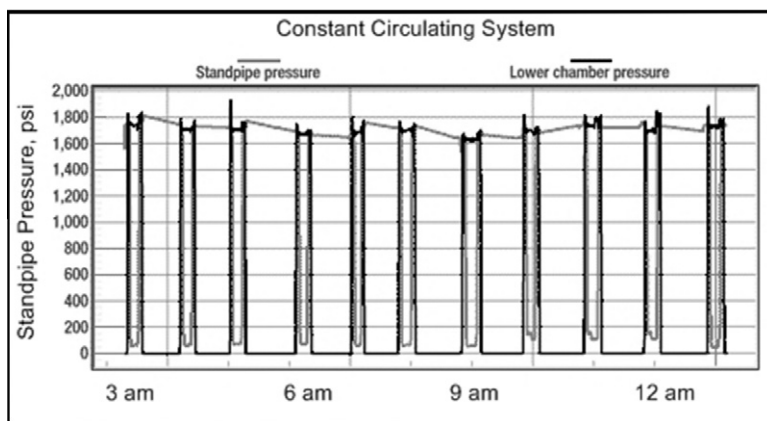


Figure 5.5 Graphic reports can also be prepared for each stage of the standpipe and lower chamber pressures.

5.9 Case History

Calderoni et al. (2006b) report the first commercial application of the CCS system for reentry and deepening of the Port Fouad Marine Deep 1 (PFMD1) well in the Mediterranean Sea, offshore Egypt. This exploration well had been drilled and suspended above the objective after encountering hole problems related to narrow differences between pore pressure and fracture pressure gradients. Before installing CCS on the rig, the operator tested the system with a satisfactory result.

PFMD1 was successfully reentered, and 1319 ft (402 m) of 8½-in. hole was drilled with uninterrupted circulation to 16,375 ft (4991 m), where a 7-in. liner was run. Rotating BOP equipment was installed, and a 5½-in. hole was drilled to a total depth of 17,205 ft (5244 m), continuously pumping mud to both the drill pipe and the annulus. MWD/LWD/PWD tools recorded formation data and real-time ECD measurements in both hole sections. Figure 5.6 shows that reentering and deepening the PFMD1 well, using continuous circulation, was a great success. The system demonstrated remarkable reliability in its first commercial field application, making 522 connections while drilling and tripping with no interruptions to circulation nor additional rig time attributable to mechanical failure.

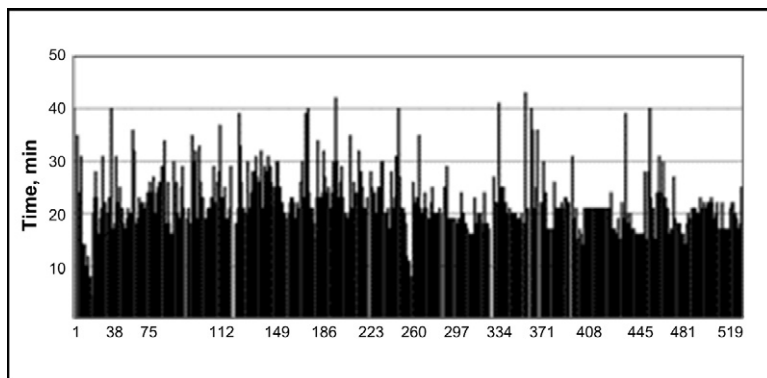


Figure 5.6 In its first commercial application, the system made 522 connections while drilling and tripping, with no interruptions to circulation.

The second commercial CCS was deployed in 2005 on Saipem's *Scarabeo 5* semi-submersible offshore of Norway. The objective was to maintain continuous ECD overbalance while drilling, washing, and reaming in an undrilled formation below a depleted reservoir section. With uninterrupted circulation, the ECD was maintained within the required range, and 216 m (709 ft) of 8½-in. × 9⅝-in. hole were successfully drilled and underreamed to TD at 17,592 ft (5362 m) measured depth. The system performed reliably throughout, making 151 connections while drilling and reaming, in an average time of 19 min/connection, with no interruptions to circulation. This more than satisfied the requirements of the drilling engineers.

5.10 Safety

The CCS has been designed with a clear emphasis on safety, principally for the personnel involved but also for the well being drilled. Drilling with the system does not involve any changes to the drill string. No additional components or connections are required. It is exactly as for normal drilling. No drill string leaks, or attributable damage, have been recorded during drilling with the system. All connection operations—making up or breaking out tool joints at circulating pressure—take place within the main unit.

The main unit is constructed from tried and proven blowout preventer components and is regularly tested. The ram seals, which are subject to wear from the drill pipe moving through them while pressurized, are easily changed during the time between connections while drilling continues with the main unit in place. The operation of making and breaking connections while continuously circulating does not require manual intervention. The process is controlled from the HMI touch screen, and members of the rig crew are isolated from the main unit and ancillaries and protected from any possibility of injury.

Questions

1. What are the advantages of maintaining drilling fluid circulation throughout the operation?
2. How does CCS allow drilling through a narrow drilling window?
3. How does the annular pressure profile differ between CCS and applying surface back pressure to maintain pressure at a specific point?
4. What are the main elements of the CCS?
5. Explain pipe handling with CCS.
6. How do MWD, LWD, and PWD benefit the operation to achieve its objectives?
7. What are the benefits of an integrated recording system?

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Answers

1. With continuous circulation, a steady equivalent circulating density can be maintained. Also, it minimizes the positive and negative pressure surges associated with making a connection under normal drilling conditions.
2. CCS maintains ECD throughout the operation and eliminates consideration of a margin for static and dynamic conditions.
3. The annular pressure profile is the same for both techniques while circulating. During pipe handling, the annular pressure profile does not change for CCS. However, applying surface back pressure increases the annular pressure profile, hydrostatic pressure, by a constant amount (see Figure 5.7).
4. The main unit, mud diverter unit, top drive interface, human/machine interface, and control container.
5. When the joint is in the chamber, the upper and lower rams are closed to seal the chamber. Then, the chamber is pressurized and the connection is broken. The saver sub is raised up and down, and the chamber is divided to two sections, an upper section with a separated stand and a lower chamber holding the drill string. Circulation is diverted to the lower chamber to maintain continuous circulation. The upper chamber is depressurized to allow conventional pipe handling. When the new connection is made, the upper rams are closed and upper chamber is pressurized to equalize the pressure across upper and lower chambers. Then, the blind rams are opened and connection is made. Simultaneously, circulation is diverted from the lower chamber to the top drive system to resume drilling.

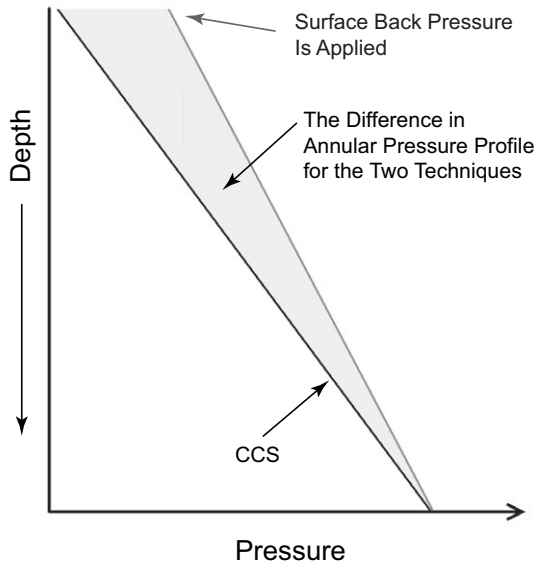


Figure 5.7 Pressure profile difference during pipe handling.

6. MWD, LWD, and PWD tools provide measuring pressure versus depth in real time and help adjust the mud properties and circulation rate.
7. The recording system
 - Provides measures for maintenance and quality control.
 - Reports the time required for each connection.
 - Reports time required for each step.
 - Reports number of connections made.
 - Monitors chamber and standpipe pressure.

CHAPTER SIX

A Simplified Approach to MPD

Dennis Moore, New Tech Engineering, and
George Medley, Signa Engineering

About This Chapter

Previous chapters detailed methods of precisely controlling bottom-hole pressure. A question arises about the precision versus cost equation needed in any particular operation. The authors of this short discussion propose that, under some conditions, extreme precision and the accompanying cost are not justified; and a simpler system is more practical and cost effective.

6.1 Introduction

In today's drilling industry, it has become more and more advantageous, sometimes even necessary, to drill wells with multiple formations simultaneously exposed, some having pore pressures approaching the fracture pressures of one or more of the others. The problem is basically quite simple. As long as the highest pore pressure open to the well bore does not exceed the fracture pressure of the weakest zone, it is theoretically possible to balance the

well with the hydrostatic pressure of the mud, if the correct density is placed throughout the well bore.

Also, in situations where the well-bore stability limit approaches the fracture pressure, the well bore will collapse if the equivalent mud weight does not exceed the well-bore stability limit.

The difficulty is that, when the mud is circulated, the additional pressure imposed by annular circulating friction, normally expressed as an equivalent circulating density, can exceed the fracture pressure of the exposed weaker formation.

Managed pressure drilling techniques are used to solve this problem by selecting a mud weight that must be supplemented by some additional pressure to balance the maximum exposed pore pressure or maintain well-bore stability. While circulating, at least part of this additional pressure is supplied by the ECD. Under static conditions, surface pressure is adjusted to balance the well. Hydraulics models or pressure-while-drilling tools are normally used to determine the adjusted surface pressure.

The objective is to maintain a constant bottom-hole pressure throughout the transition from circulating to static conditions and back during connections or other similar events. The difficulty is in how to go from circulating at balance with little or no annular surface pressure to static conditions with a higher annular surface pressure. During this transition, the down-hole pressures should be kept in a range that prevents fracturing the weaker formations, influx from the highest pore pressure, or well-bore collapse.

6.2 Discussion

Since the earliest attempts at constant bottom-hole pressure applications, it has been realized that maintaining the exact balance in the well is no easy task. The complexity lies in the fact that an initial force is required to start circulating the drilling mud, and at lower shear rates (pump speeds), the shear-rate/shear-stress relationship is not linear. This situation prompted a number of creative solutions.

Systems have been developed that isolate the drill string and reroute the surface fluid flow path, thereby allowing connections to

be made without ever stopping the pumps or altering circulation in the well bore.

Another approach is to continuously circulate through a surface loop connected to the annulus to supply the annular pressure at the surface required to balance the well when the mud pumps are off. An extra pump is often dedicated to this circulating system. The choke through which the fluid is being circulated, and sometimes the surface circulating pump, are software controlled to maintain a very precise surface and, therefore, down-hole pressures during transition periods. These systems can maintain a very constant pressure, as illustrated by the portions of Figures 6.1 and 6.2 labeled “Auxiliary Pump Assisted MPD Connections.” In the figures, curve depth intervals below approximately 13,400 ft are taken from actual well data.

The two primary problems with these types of systems are that they can be complicated and expensive. The equipment for the surface systems currently commercially available to either maintain

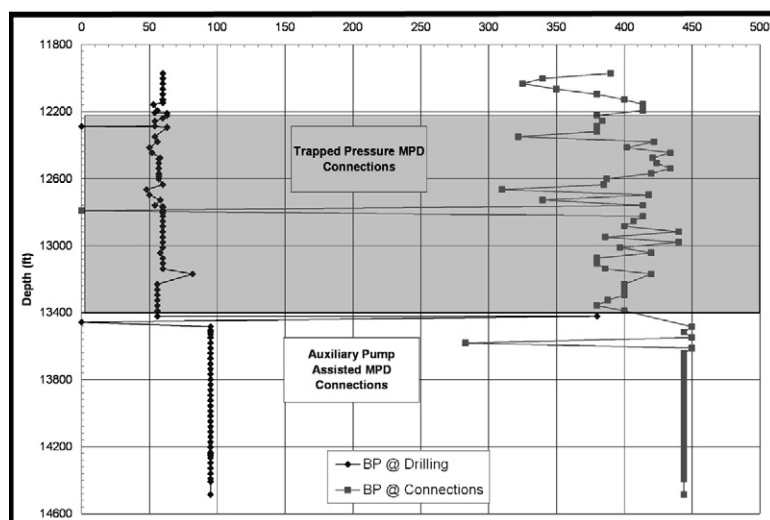


Figure 6.1 Annular surface back pressure versus depth. (Courtesy of Medley, Moore, and Nauduri, 2008.)

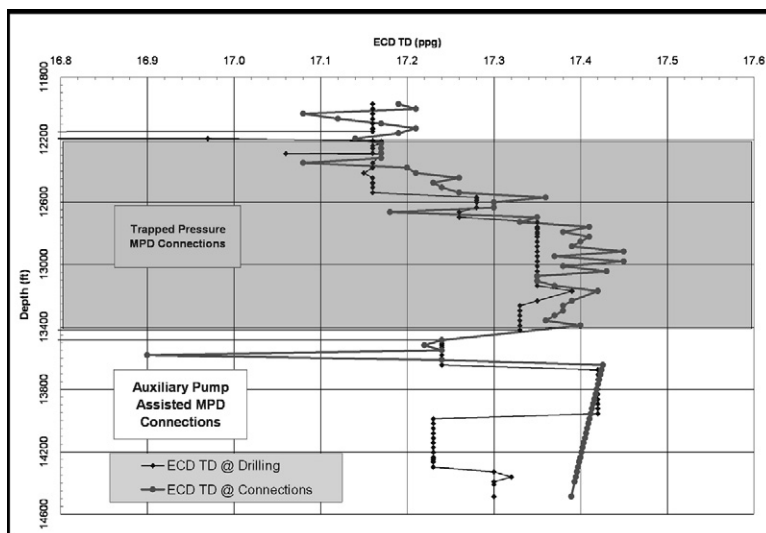


Figure 6.2 ECD at total depth versus depth. (Courtesy of Medley, Moore, and Nauduri, 2008.)

continuous well circulation or continuously circulate through a surface choke can also require extra space, which makes their use difficult in situations where space is at a premium, including small rig floors, offshore installations, or small locations. As the complexity of a system increases, normally so do the cost and incidence of malfunction.

Questions that should then be asked before applying MPD in any situation include these:

- What is the simplest, least expensive way to control surface pressure while going back and forth between static shut-in and circulating conditions? How closely can pressure be controlled with that method?
- How closely does the pressure really have to be controlled, and what happens if the pressure is not so precisely controlled?
- How good is good enough when it comes to pressure control in this situation?

6.3 A Simplified Approach

A simple way to control surface pressure is to take returns through an adjustable choke while drilling. Then, gradually close the choke while slowing the rig pumps to a stop, thereby “trapping” the required pressure on the annulus. Conversely, gradually open the choke while slowly bringing the rig pumps from a stop to drilling speed. Most field personnel are familiar with how to do this based on well-control training, since that is how the pumps are brought on when circulating out a kick.

The portions of Figures 6.1 and 6.2, labeled “Trapped Pressure MPD Connections” (the depth interval is approximately 13,400 ft in both figures) show actual field data from a number of connections made while using this method. It is obvious from these data that there is a larger variation in bottom-hole pressure when using this method than when using the more complex method. However, on closer examination, the fluctuations are actually not very large, representing variations in equivalent mud weight to which the formation is exposed of around 0.1 ppg or less, in this example; equal to about 50–100 psi (300–700 kPa).

If the pressure within the well bore is allowed to fall below that required to balance the highest exposed pore pressure, an influx will occur; if the pressure within the well bore exceeds the fracture pressure of the weakest exposed formation, a loss of drilling fluid will occur. In either case, the volume of influx or loss is small, since the time that pressures are outside the allowable range is only a few minutes in each case.

Normally, a small loss of fluid has fewer undesirable consequences than an influx of formation fluids, so the obvious course of action when that is the case is to make sure that the well-bore pressure always exceeds the highest exposed pore pressure. While exceeding pore pressure may result in the loss of some drilling fluid, it may not really be too serious.

Table 6.1 shows the results of a dynamic kill test in which circulation rates were intentionally increased until the ECD exceeded the fracture pressure of some weaker formations. This was done

Table 6.1 Dynamic Kill Test Results

Pump Rate (gpm)	ECD (ppg)	Mud Loss Rate (bbl/hr)
180	11.60	0
252	12.06	18
349	12.61	90
401	12.95	144
433	13.18	176

Source: Strickler, Phillips, and Moore, 2006.

before drilling into a higher pore pressure to determine the loss rates that would occur during a dynamic kill operation and may later be required to successfully cement casing in the well (Strickler, Moore, and Solano, 2006).

As expected, the loss rates increased as the amount by which the well-bore pressure exceeded the fracture pressure increased. The various pump rates were originally increased and the corresponding loss rates recorded. The pump rates were then decreased to the rates previously recorded, and the loss rates observed duplicated those recorded earlier for each pump rate. This test was conducted several times, and each time, the loss rates for each pump rate matched previous results.

Similar behavior of fluid loss has been observed numerous times in various locations and has been quite predictable. The significance of this observation is that, when the fracture pressure is slightly exceeded for a short period of time while stopping and starting the pumps, the mud loss is small and lasts only until the pressure leaks off to the exposed minimum fracture pressure. In addition, when the fracture pressure is exceeded, some portion of the mud lost is often recovered as the well-bore pressure is again reduced below the fracture pressure. The cost of the mud lost in this process, in most cases, is much less than the cost of the complicated systems utilized to prevent those losses. Basically, manual control of the choke, while stopping and starting the pump, gives satisfactory results with less cost and complexity.

6.4 Implementation

A simple way to apply this simplified method is to use a hydraulics model to develop a schedule of surface annular pressure required to maintain balance at a number of pump speeds as the pump is shut down or brought up to the desired circulation rate. To shut down the pump, for example, to make a connection, the choke opening is first reduced until the annular pressure reaches the desired pressure at the next pump rate on the schedule, then the pump speed is reduced to the one matching that annular pressure. Next, the choke opening is again reduced until the annular pressure reaches the next required pressure, the pump speed is reduced to the one required to match the new annular pressure, and the process continues stepwise until the annular pressure is at the maximum calculated value and the pumps are stopped. The stepwise process is illustrated in Figure 6.3.

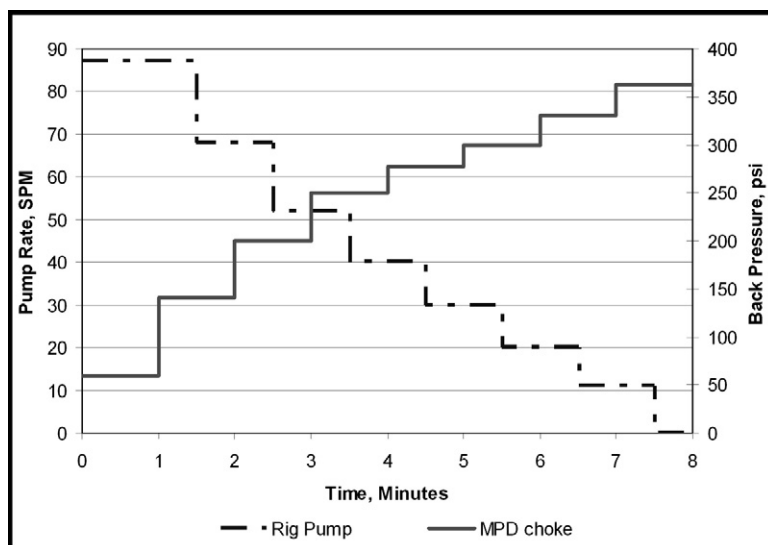


Figure 6.3 Pump rate and back-pressure schedule to maintain the BHP (Courtesy of Medley et al., 2008.)

Note that the pressure increments of increase (or decrease) are not equal at the end points. This is because of the way chokes and pumps function, as well as the fact that shear stress does not exhibit a linear relationship to changes in shear rate.

Since the amount by which the ECD exceeds the desired pressure is very small and short lived with each increase in annular pressure, even including minor errors by the choke operator, any associated mud losses also are small. If this overbalance is greater than desired, then the size of the steps can be reduced until the losses are minimized.

The procedure is reversed when bringing the pumps up to speed. Start the pump to the first speed in the calculated schedule, gradually open the choke until the annular pressure matches the value calculated to balance pore pressure at that pump speed. Then, increase the pump speed to the next speed on the schedule, open the choke to the corresponding calculated pressure, and repeat the process stepwise until the desired circulation rates are reached. As discussed, overbalances are small and short lived, so any associated mud losses also are small.

Even with the cost of the most expensive mud systems in use today, if this procedure is repeated every time the pumps are shut down and brought on line, the cost of the mud lost will be much less than the cost of the complex systems required to exactly match the pressures throughout the process.

Equipment requirements and system complexity are also greatly reduced, thus reducing the probability of a failure. It should be noted that field personnel should also be trained in this method in case of a failure or malfunction when a complex system is used, as was the case on the well illustrated in Figures 6.1 and 6.2.

6.5 Conclusion

- By using the ECD to help control formation pressure, it is possible to drill formations in which the fracture pressure is very close to the required minimum well-bore pressure.

- The part of the operation when the well is most likely to get out of balance is when shutting down the pumps and bringing them back on line, for example, during connections.
- The surface equipment systems make it possible to maintain a constant bottom-hole pressure while shutting down the pumps and bringing the pumps back on line. These systems are complex, expensive, and require space, for equipment and personnel, that is often at a premium.
- It is possible to maintain the down-hole pressure within a reasonable range using manual control of an adjustable choke, through which all returns from the well are routed. When using this method, the loss of mud is small and manageable and the cost of this loss is much lower than the cost of the equipment and personnel required to prevent it.
- Certainly, some applications require the more precise control achievable with the elaborate systems; but, in many cases, manual control of the choke is a simple, acceptable alternative.
- Even when a complex system is used, field personnel should be trained in and familiar with manual control in case of equipment failure in the complex systems.

Acknowledgments

The authors acknowledge Greg Salvo of Cypress E&P for his efforts to improve the industry knowledge base and for providing data and ideas, and the contribution of Sagar Nauduri of Sigma Engineering for assistance with data analysis.

Questions

1. What is the basic argument in this chapter?
2. Given that observation, why is it possible?
3. The step procedure in Figure 6.3 is the basis for correcting surface pressure when the flow rate is changed. In Figure 6.3,

the x -axis on the chart is time in minutes. What is the basis for the time scale. What is the basis for the y -axis?

4. Turn Figure 6.3 into a chart for starting the pump.
5. In Chapter 9, Section 9.2, the manufacturer proposes a computer-controlled stepping choke. What are the advantages and disadvantages of such a system.
6. In Chapter 9, Section 9.2, the manufacturer proposes a pressure-controlled choke. What is the advantage or disadvantage of such a system?

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Answers

1. The basic argument in this discussion is that precision control of bottom-hole pressure is not always necessary.
2. The reason this is possible is that losses when the fracture pressure is exceeded are small, especially when the amount by which they are exceed is small and the duration short. This is detailed in the last paragraph of Section 6.3. Formation plasticity, or ballooning as it is often called, explains why some of the lost fluid is often recovered, but this is not really the primary reason this method works.

3. If the x -axis on the chart is time in minutes, the basis for it is experience or an estimate of how long it will take to bring each step to equilibrium. The y -axis is both the pump rate and choke back pressure. For planning purposes, this needs to be derived from a hydraulics equation. It might be rig verified with a MWD bottom-hole pressure tool before drilling the cement out of a casing string.
4. To turn Figure 6.3 into a chart for starting the pump, see the solid line in Figure 6.4, and Table 6.2.

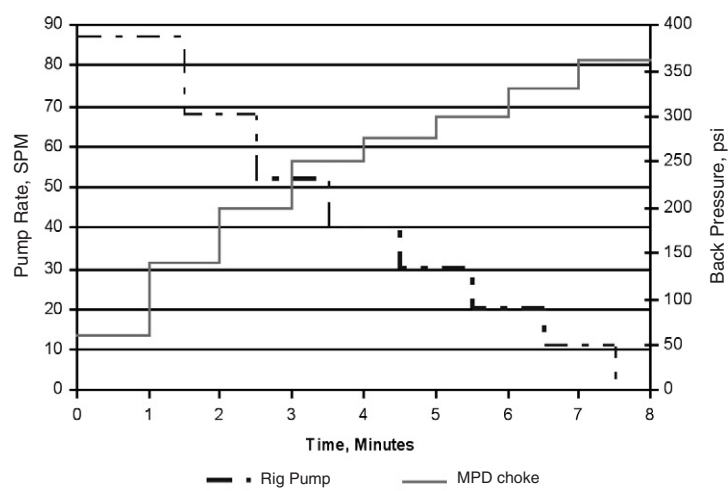


Figure 6.4 Figure 6.3 turned into a chart for starting the pump.

Table 6.2 Procedure for Starting the Pump

Pressure (psi)	Time (min)	Pump Rate (spm)
360	0	0
325	1	10
300	2	20
275	3	30
250	4	40
200	5	52
140	6	68
55	7	88
13	8	88

5. A computer-controlled stepping choke automatically follows the pump rate and uses smaller steps. The precision of the system would be much better. The technical problem would be to ensure the program is tied properly to pump rate and choke pressure and allowed lag time for the pressure response to limit “jittering.” Other disadvantages to this system are complexity and cost.
6. An annular pressure following choke makes it easy for manual control by the ability to dial in a pressure and follow a pump rate chart. This system is an intermediate step between the simplest, least-expensive system as described in this chapter and the more complex and expensive computer-controlled chokes described elsewhere in this book.

CHAPTER SEVEN

Mud Cap Drilling

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About This Chapter

In mud cap drilling, mud and water are pumped down the well bore and drill pipe to prevent kicks and control loss of circulation while drilling in fractured formation or in a layered formation with different pressure regimes. This method reduces the time and cost associated with continuous well-control issues and loss of drilling fluid. This chapter reviews technical concerns and issues of mud cap drilling and pressurized mud cap drilling.

7.1 History of Mud Cap Drilling

What we now call mud cap drilling has been widely used for a very long time. Quite simply, mud cap drilling is employed whenever it is difficult or impossible to maintain circulation, as in fractured or vugular carbonate formations. To illustrate its development and application, some well-known, published cases are described and simplified for ease of discussion.

The term *mud cap drilling* was first widely applied in the Austin Chalk fields of South and Central Texas. This fractured carbonate was exploited using horizontal wells. Since the wells were horizontal within the same formation, reservoir pressure was essentially the same throughout the lateral, if no depletion from offset wells was

encountered. Production was from natural fractures, some of which were quite large.

In the simplest and most common situation, casing was set into the top of the chalk and only the chalk was exposed. When the first of the fractures was encountered, either a kick was taken or circulation was lost, depending on the mud weight and pore pressure. This fracture could then be balanced either statically or dynamically but not both simultaneously. In the beginning, plugging the fractures with lost circulation material (LCM) was attempted but proved to be impossible in many cases.

Drilling typically continued underbalanced, pretty much by necessity. It was possible to adjust the mud weight, choke pressure, or a combination of the two to maintain circulation and control the influx to a level that could be managed with the available surface equipment. The shallower, southern part of the trend had lower pressure and produced primarily oil, so it presented no real problems. As development progressed northeast, however, the targets got deeper, pressures higher, and the production was gas, so things got much more complicated. Still, so long as only one fracture was open or the open fractures were very close together, it was usually possible to adjust the mud weights and choke settings to the point that surface pressures and production rates were manageable.

Things really got complicated when several fractures were encountered and they were widely spaced along the horizontal well bore. Now, it became impossible to balance all the fractures while maintaining circulation, due to differences in well-bore pressure caused by circulating friction along the horizontal hole. The situation was further complicated by fractures depleted by offset wells.

Many of these wells were being drilled in deeper areas with higher formation pressures, resulting in production rates and circulating surface pressures that exceeded the capacity of the available rotating control device (RCD), or rotating head, and mud gas separators. Whenever surface pressures got too high for the RCD, drilling was stopped, the BOPs were closed, and the well circulated until the surface pressure could be reduced to an acceptable level. Since

multiple fractures, sometimes with differing reservoir pressures, were exposed to differing equivalent circulating densities, down-hole crossflow and mud losses occurred. This became very time consuming and expensive, due to the large volumes of weighted mud often lost, in addition to time being devoted to circulating instead of making the hole.

Mud cap drilling was developed to reduce the losses of time and mud caused by these higher pressures and loss of circulation. In a very simple form, heavy kill mud was pumped (bullheaded) down the annulus until the well went on a vacuum. Drilling was then continued, pumping fresh water down the drill string with no returns to the surface. A float was run in the string to prevent backflow up the drill pipe. Periodically, the well would kick and additional kill mud would be pumped down the annulus until the well was again on a vacuum. This continued for the remainder of the hole. While no cuttings were returned to the surface, gamma ray logs were normally run as part of the measurement while drilling (MWD) package to facilitate geosteering, so adequate geologic information was obtained without them.

Virtually the same procedure was used for tripping, with kill mud pumped down the annulus to supplement the fill-up mud as necessary to keep the well under control. When the BHA reached the surface, additional kill mud was pumped to make sure that the well did not kick while pulling the BHA out with the rotating head rubber removed. Once the BHA was out, the blind rams were shut while the BHA was changed. Kill mud was then pumped as needed to send the well on a vacuum before opening the blind rams and starting back in the hole.

While quite a bit of mud was often lost while drilling and tripping like this, the amount of mud lost to the hole, as well as the amount of time spent circulating instead of drilling, was much less than was lost when fighting the well and trying to drill it conventionally, thus making it much more economically attractive. All the cuttings generated while drilling went into the fracture or fractures, which were taking the water being pumped down the drill string to drive the motor and MWD and to clean and cool the bit.

7.2 Pressurized Mud Cap

The next step in mud cap drilling came when the technique was applied to very thick fractured formations. While it was possible to balance a single point in the reservoir either statically or dynamically, since the reservoir contained either oil or gas with a very different hydrostatic gradient than the drilling fluid, it was not possible to simultaneously balance fractures separated by any significant vertical distance. The same mud cap methods used so successfully in the Austin Chalk immediately came to mind. However, the formations in question were quite sour and it was undesirable to allow the sour gas to come to surface. In addition, when using normal (floating) mud cap techniques, it was always a source of some concern that the fluid level was not known and kicks from the well were often sudden and sometimes quite forceful. Acoustic fluid-level guns were sometimes employed to try to monitor what was going on in the well bore, but since the gas migration was transient, the results had limited value. The pressurized mud cap technique was developed to continuously monitor the pressure at the surface.

This method, also variously called *pressured mud cap*, *light annular mud cap*, or *closed-hole circulation drilling*, places a column of mud in the annulus that is lighter than required to balance the formation pressure. Figure 7.1 shows the surface equipment required for pressurized mud cap drilling. Drilling is conducted through a rotating head with the well shut in at the surface and surface annular pressure used as an indicator of what is going on downhole. Sacrificial drilling fluid (preferably something economical and nondamaging) is pumped down the drill string, and all fluid and cuttings are pumped back into the fractures or vugs. By maintaining the hole full, with a more or less static column of fluid, mud losses are reduced and constant contact with the reservoir is maintained.

The static surface annular pressure is the difference between reservoir pressure at the top fracture and the hydrostatic pressure exerted by the annular fluid. Pumping annular pressure is typically slightly higher, the amount higher determined by the friction pressure required to pump into the fractures. If gas migration occurs, the annular pressure rises as annular fluid is replaced by gas. As that gas rises to the surface and expands, the annular pressure increases accordingly. To

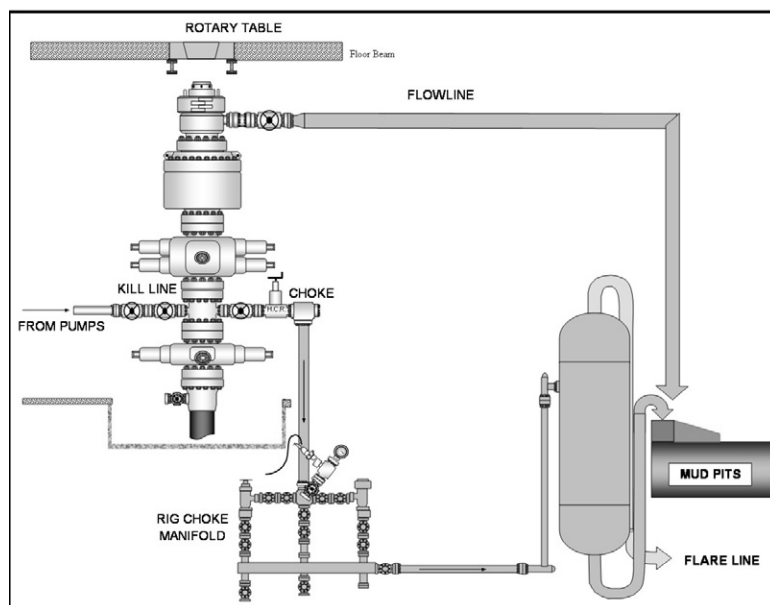


Figure 7.1 The BOP, RCD, choke manifold, and separator for mud cap drilling.

counter this, when the annular pressure rises above a predetermined value, additional fluid is pumped into the annulus, displacing the gas and contaminated fluid back into the formation until the previous annular pressure is restored. In this way, control of the well can be maintained and undesirable materials such as H_2S need never be brought to surface. Sweep, Bailey, and Stone (2003) reported that this technique made it possible to drill very thick, highly fractured, sour reservoirs that, in some cases, had not been completely penetrated previously.

7.3 Floating Mud Cap

The oldest and simplest mud cap technique is the floating mud cap. In its simplest form, the hole is drilled until circulation is lost, at which point drilling continues with no returns. The fluid level “floats” somewhere downhole at whatever level balances the formation pressure in the lowest pressured fracture or vug exposed. When necessary, fluid is pumped into the annulus to maintain the

well on a vacuum. In cases where reservoir pressure is low enough and where an adequate supply of water is readily available, water may be continuously pumped into the annulus to maintain well control. This is especially common when working on depleted gas wells that readily accept fluid.

So long as fluid is being pumped into the annulus fast enough to carry migrating gas and produced fluid back into the formation, the well will not kick. Fluid velocity in the annulus can range from 400 to 5400 ft/hr with typical velocities being in the range of 1000–2000 ft/hr. Continuous annular injection is applicable if either the time required to complete the work is short or unlimited kill fluid (usually water) is available. Very little surface equipment is required, so rig-up is simple and only a pump and an RCD may be required, unless reservoir pressures are high enough to require high-pressure pumping equipment and replacement of the rig's standpipe and mud lines with those having a higher pressure rating. The following example illustrates the principles involved in floating mud cap drilling.

Example 7.1

A vertical hole in a carbonate reservoir:

Casing: 7 $\frac{1}{8}$ -in., 39 lb/ft, set at 9010 ft.

Hole size: 6 $\frac{1}{2}$ -in.

Drill pipe: 4-in. FH, 14 lb/ft (5 $\frac{1}{4}$ -in. tool joint OD).

Drill collars: 4 $\frac{3}{4}$ -in. OD, 2 $\frac{1}{4}$ -in. ID, 47 lb/ft.

Drilling fluid rate: 225 gpm.

Top of reservoir: 9000 ft KBTVD.

Reservoir pressure: 5616 psi at 9000 ft.

Reservoir fluid: Gas, assume 0.1 psi/ft hydrostatic gradient.

First fracture: 9100 ft.

Second fracture: 9300 ft.

Third fracture: 10,000 ft.

The well is to be drilled just into the top of the reservoir and 7 $\frac{1}{8}$ -in. casing run and cemented about 10 ft into the target zone.

Solution to Example 7.1

Formation pressure is estimated (correctly) from offset data to be 5616 psi at 9000 ft, so the mud weight required to balance formation pressure at that point is

$$\frac{5616}{(0.052 \times 9000)} = 12.0 \text{ ppg} \quad (7.1)$$

Drilling proceeds below the 7½-in. casing with 12.0-ppg water-based mud until the first fracture is encountered at 9100 ft. The formation pressure is

$$5616 + [(9100 - 9000) \times 0.1] = 5626 \text{ psi} \quad (7.2)$$

Under static conditions, this is equivalent to

$$\frac{5626}{0.052 \times 9100} = 11.9 \text{ ppg formation pressure} \quad (7.3)$$

The static well-bore pressure is

$$12 \times 0.052 \times 9100 = 5678 \text{ psi} \quad (7.4)$$

The static well-bore pressure is slightly overbalanced.

When the fracture is encountered while drilling, the pumps are running at 225 gpm, so the circulating friction on top of the static mud weight results in an ECD of 12.5 ppg (5882 psi) and returns are lost. If the mud weight is reduced to 11.4 ppg to balance the well dynamically, then the well continues to flow when the pumps are shut down. Therefore, either underbalanced or managed pressure drilling techniques are required for drilling to continue. No matter how drilling continues, when the second fracture is encountered at 9300 ft, the situation becomes more complicated. Pore pressure in the second fracture is

$$5616 + [(9300 - 9000) \times 0.1] = 5646 \text{ psi} \quad (7.5)$$

This is equivalent to

$$\frac{5646}{0.052 \times 9300} = 11.7 \text{ ppg} \quad (7.6)$$

If drilling is attempted with 11.9-ppg mud, the static well-bore pressure is

$$11.9 \times 0.052 \times 9300 = 5755 \text{ psi} \quad (7.7)$$

And, if circulating 11.4-ppg mud, then the ECD at 9300 ft is 11.9 ppg, resulting in the same situation. The problem is this: If the mud weight is reduced to balance the second fracture, the first fracture flows. Even if the well is merely shut in, cross flow occurs down the hole. If drilling is continued, returns are lost into the second fracture, the fluid level in the well bore falls, and the first fracture then is underbalanced and flows. If drilling is continued (or the second fracture is encountered at a greater depth, such as at the location of the third fracture), the problem is even worse. Reservoir pressure at the location of the third fracture is

$$5616 + [(10,000 - 9000) \times 0.1] = 5716 \text{ psi} \quad (7.8)$$

This is equivalent to

$$\frac{5716}{0.052 \times 10,000} = 11.0 \text{ ppg} \quad (7.9)$$

Pressure in the well bore, if drilling with 11.4-ppg mud to balance the first fracture, is 11.9 ppg, so there is now a 0.9-ppg difference in the formation in equivalent mud weight between the first and third fractures, something that is impossible to handle conventionally without losing returns or taking a kick. Note that the pressure in the bottom fracture is slightly higher than in the top one, but the gradient is substantially lower (Figure 7.2).

Historically, various methods have been employed to seal up at least one of the fractures, to allow drilling to continue. In some cases, it has not been possible to stop the losses. Even if it is possible to seal up the vugs and fractures of the loss zone with lost circulation material, cement, or something similar, these fractures are the primary production conduits, so plugging them defeats the purpose of drilling wells in the first place. Polymer materials that break after some period of time have been used with mixed success. In some

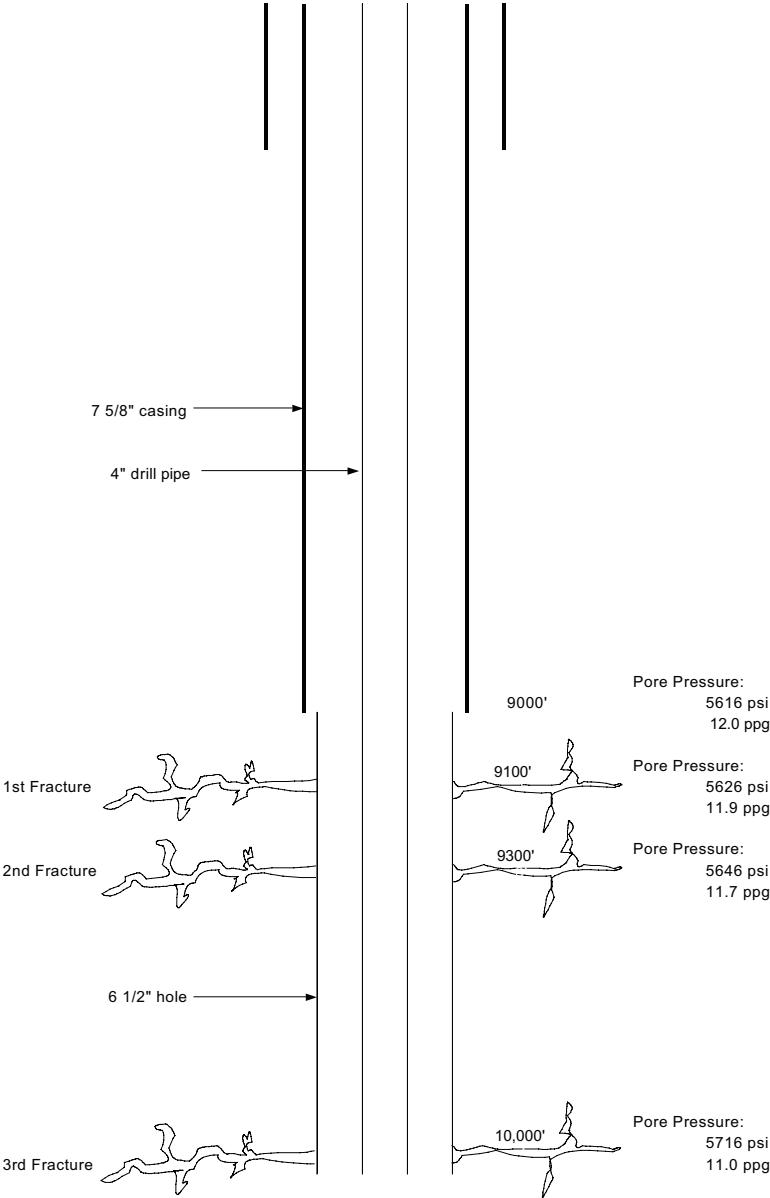


Figure 7.2 Example mud cap candidate well.

cases, it is not possible to plug the fractures or vugs with anything—permanent, damaging, or not.

7.4 Mud Cap Operation

7.4.1 Mud Cap Drilling

When the first fracture is encountered, underbalanced drilling or managed pressure techniques may be used to balance the well or mud cap techniques can be implemented immediately. For the sake of illustration, assume that normal MPD methods are employed after drilling the first fracture and floating mud cap drilling is not adopted until the second fracture is encountered. With the first fracture exposed, to keep the well from kicking with the pumps shut off, as was shown previously, at least 11.9-ppg mud must be used.

After encountering the second fracture, the hole will not remain filled with 11.9-ppg mud, so as losses occur into the second fracture, the first fracture kicks. Even if the mud weight is reduced to balance the first fracture, the pressure in the well bore is higher than that in the formation, and the same thing happens. When the well kicks, some of the annulus becomes occupied by gas, which must be displaced back into the formation, and it will not be possible to kill the well by pumping 12.0-ppg mud into the annulus without displacing the entire annulus.

To reduce the amount of mud required, heavier kill mud, usually 15–18 ppg, is pumped down the annulus until the annulus is again dead. It should be obvious that the well is not dead in the traditional sense but merely not flowing at the surface. By convention, it is said to be “dead,” though in fact it is only “dead” at the surface, while undetectable cross flow between zones may be occurring down the hole. All this takes place whether or not pumping down the drill pipe is taking place.

To continue drilling, some sacrificial fluid is pumped down the drill pipe. Water is usually used, because it is plentiful, inexpensive, and relatively nondamaging to the carbonate formations in which mud cap drilling is applicable. To continue drilling, the surface pressure must be sufficient to overcome the difference between the hydrostatic pres-

sure of the water and the formation pressure. If the freshwater fluid is going into the second fracture, this pressure becomes

$$5646 - (8.34 \times 0.052 \times 9300) = 1613 \text{ psi} \quad (7.10)$$

The “circulating” (pump) pressure is the sum of: the difference between the pore pressure and the hydrostatic pressure of mud + the surface equipment friction pressure + the pressure drop through the drill string + the pressure drop across the BHA + the pressure drop across the bit.

$$\text{Circulating pressure} = 1613 + 15 + 295 + 300 + 145 = 2352 \text{ psi} \quad (7.11)$$

Obviously, these values vary, depending on surface equipment, bottom-hole assembly configuration, and the nozzles in the bit. The pressure in this case is within the capability of the equipment found on most rigs, so mud cap drilling can proceed with no special equipment. If this pressure is outside the acceptable operating limits for the rig’s equipment, all the necessary equipment can be replaced with equipment that is fit for this purpose. Drilling now proceeds with no fluid at the surface in the annulus and neither flow nor pressure on the annulus, while pumping water down the drill string. Pump speeds are maintained at normal drilling rates, sufficient to power the down-hole motor and MWD while cleaning and cooling the bit, just as in normal drilling operations.

In this case, however, all the cuttings and sacrificial fluid pumped down the drill string go into the formation, initially at the bottom open fracture and continuing into whatever fracture or vug is open that most easily takes the fluid and cuttings. Since the hydrostatic pressure of the original and kill mud in the annulus is higher (at least initially) than the highest gradient open in the well bore, no circulation or flow to the surface occurs.

The situation down the hole is more complicated. The fluid gradient inside the well bore is that of water plus cuttings, which is always higher than that of the reservoir fluid (unless the reservoir contains only water), so everything should continue entering the lowermost open vug or fracture. The real question is: Why doesn’t everything, including the mud in the annulus, fall to the level required to balance

the lowest gradient open fracture and keep the system in flux, so that constant pumping is required to maintain control of the well?

Several things help mitigate this seemingly impossible situation. Beginning at the lowermost fracture and working back up the hole, the first thing to help is that some friction is involved in putting fluid into the fracture—the higher the rate of injection, the higher the friction pressure. There is always some theoretical injection rate at which this friction pressure is adequate to balance the pressure differential, thus stabilizing the system. This friction pressure varies widely, and in most cases where mud cap drilling is feasible, this alone is not enough.

Moving up the hole, the gradient of the fluid between the first and second fractures is now water and much closer to that of the reservoir fluid than when mud was present, even though it is still not the same. If the reservoir is gas bearing, this difference in gradient is still substantial. If the formation is oil bearing at reservoir conditions of temperature and pressure, however, the difference in gradient is greatly reduced. Since the heart of the problem is the difference in gradient between the first and the third fracture, the fluid between those two is not 100% water but contains some fraction of reservoir fluid. If the pumps are shut off, this interval soon contains 100% reservoir fluid, due to gravity segregation above the point in the well bore where fluid exits to the loss zone, so the hole interval comes very close to being balanced. While pumping and drilling, the percentage of reservoir fluid in this hole interval depends on the conductivity of all exposed fractures, so it becomes somewhat self-regulating. The higher the conductivity of and gradient differences between the fractures are, the higher the percentage of reservoir fluid in the interval between them will be. This reduces the difference in gradients and helps stabilize the system.

It is obvious that the system is inherently unstable, since it includes an annular fluid level and annular pressure that fluctuates with the presence of reservoir fluid in the annulus, which migrates over time due to gravity segregation. That makes it necessary to pump additional kill mud into the annulus periodically to keep the well from flowing. How much must be pumped and how often de-

depends on how all these forces interact and change as an additional hole is drilled, additional fractures are exposed, the existing fractures try to bridge or plug, and many other things.

7.4.2 Mud Cap Tripping

When tripping out of the hole, original-weight mud is pumped into the hole in proper quantities to replace the pipe removed and kill mud is pumped as needed if the well starts to flow. Once the BHA is reached and the element is to be removed from the rotating head, additional kill mud is typically pumped to ensure that the well remains dead until the bit clears the BOPs. Once the bit is at the surface, the blind rams are closed and the casing pressure monitored.

Before opening the blind rams to trip in, if there is any casing pressure or if it has been a long time since they were closed, additional kill mud is pumped in to make sure the well stays dead until the BHA can be run into the hole and the rotating head element installed.

7.5 Pressurized Mud Cap Operation

7.5.1 Pressurized Mud Cap Drilling

Assume that the same well is drilled under the same conditions but, instead of a floating mud cap, pressurized mud cap drilling is selected to continue with. The pore pressure at the first fracture is equivalent to 11.9 ppg, but with a pressurized mud cap, some positive pressure is used for most operations, so a lower mud weight is used. If a target surface pressure of 150 psi is selected, the required mud weight is now

$$11.9 - \frac{150}{0.052 \times 9100} = 11.58 \text{ ppg} \quad (7.12)$$

Therefore, 11.6-ppg mud is used to drill the well.

The actual static annular surface pressure therefore is

$$5626 - (11.6 \times 0.052 \times 9100) = 137 \text{ psi} \quad (7.13)$$

To get to this condition, the annulus is shut in and 11.6-ppg mud is bullheaded down the annulus via the kill line, until all the original-weight mud is displaced by 11.6-ppg mud and the surface pressure is

almost equal to 137 psi with the pumps off. Drilling then proceeds, pumping water down the drill string, as with the floating mud cap.

When pumping, the annular pressure increases and stabilizes at some pressure slightly higher than the static 137 psi. This increase is due to the friction pressure of pumping into the fracture and also is reflected by a comparable increase in drill-pipe pressure over what it would be with no fracture friction present. By recording this pressure before beginning to drill, a baseline can be established so that, if the existing fracture begins to plug or if additional fractures are encountered, these changes in down-hole conditions can be recognized. By taking the initial annular and pump pressures at several rates, it is possible to determine how the fracture responds to various flow rates, so that it can be known what to expect should different flow rates be needed as drilling continues.

Assume that the initial fracture friction pressure is 100 psi at the initial pump rate of 225 gpm. Initial conditions are then

$$\text{Circulating drill-pipe pressure} = 2352 + 100 = 2452 \text{ psi} \quad (7.14)$$

$$\text{Circulating casing pressure} = 137 + 100 = 237 \text{ psi} \quad (7.15)$$

As drilling proceeds, the pressures start out fairly stable. Reservoir fluid in the annulus migrates upward, since it is less dense than the mud in the annulus. This can begin when the pumps are shut down during a connection or just due to gravity segregation while drilling. Whatever the initial source of the reservoir fluid, as it migrates upward, the surface pressure on the casing increases over time *with no corresponding increase in drill-pipe pressure*. This increase makes it possible to detect an influx from the formation very early. When this happens, additional mud is bullheaded down the annulus, and the influx is displaced back into the formation.

Various attempts have been made to calculate the volume that must be injected to restore a reservoir-fluid-free annulus above the top fracture. The value of these calculations is limited, because they assume that the exact density of the influx is known, as is the migration rate of that fluid through the annular fluid being used. Migration rates depend on differences in density and viscosity and can vary widely. In practice, annular fluids often react with the formation fluids to form a

high-viscosity interface that slows migration rates, sometimes very dramatically. For example, if freshwater-based annular fluid is used and the formation contains saltwater, the mud at the interface gets very thick, helping prevent further migration.

The migration that takes place through this interface continues to cause the mud to thicken wherever they mix. Something similar takes place when the reservoir fluid is oil, as an emulsion forms when the oil contacts the water-based mud. If it is necessary, advantageous, or for another reason to use an annular fluid compatible with the reservoir fluids, such as oil-based mud with oil or if the reservoir fluid is gas, a high-viscosity pill or slug can be pumped ahead of the annular fluid and spotted at the top of the first fracture, when displacement takes place, to create the same effect. In any case, by closely monitoring drill-pipe and annular pressures, it is possible to detect the influx of reservoir fluids and bullhead them back into the formation before they move very far up the hole, thus minimizing surface pressures and mud losses. As additional fractures are encountered, if the formation (and the formation gradient) is indeed continuous, the losses should go into the bottom fracture, wherever that happens to be.

7.5.2 Pressurized Mud Cap Tripping

When the pipe must be tripped out, a volume of annular mud is pumped down the kill line equal to the volume of pipe being removed. This is best done while actually pulling the pipe, since it is not possible to “get ahead” on pressure or volume as the top fracture is exactly balanced. The volume of mud pumped may be adjusted as necessary to maintain a constant casing pressure. If mud is pumped faster than the pipe is pulled, the casing pressure remains constant but excess mud is lost. If insufficient mud is pumped, an influx occurs and the casing pressure starts to rise. Additional mud is then pumped to force the influx back into the formation and maintain the casing pressure at the correct value. This is continued until pipe light conditions are approached or the BHA reached.

Pipe light describes the set of conditions under which the force exerted by the well pressure acting across the area of the pipe in the RCD

exceeds the weight of the pipe in the hole. For example, assume the annular pressure when pumping into the kill line is

$$\text{Annular pressure} = 137 + 100 = 237 \text{ psi} \quad (7.16)$$

The greatest force occurs when a tool joint is in the RCD element, so the hydraulic force trying to lift the pipe is

$$\text{Lifting force} = P \times A \quad (7.17)$$

where P = surface pressure and A = cross-sectional area of the pipe. And,

$$\text{Lifting force} = 237 \times \left(3.1416 \times \frac{5.25^2}{4} \right) = 5130\text{-lb force} \quad (7.18)$$

Assuming a buoyancy factor of 0.8227 for 11.6-ppg mud, the minimum length of drill pipe that can safely be in the hole with this pressure is

$$\text{Minimum length of pipe} = 5130 / (14 \times 0.8227) = 445 \text{ ft} \quad (7.19)$$

If no drill collars are being used, as is common when drilling horizontal holes, this is close enough. The weight of the drilling motor and nonmags are merely a safety margin. However, in a vertical hole where drill collars are used, it is obvious that pipe light conditions would be reached at a point in the drill collars. In this situation, pipe light conditions would be reached when the hydraulic force while pumping reaches

$$\text{Lifting force} = 237 \times \left(3.1416 \times \frac{4.75^2}{4} \right) = 4200\text{-lb force} \quad (7.20)$$

This happens while pulling out of the hole, when the bit reaches

$$\text{Minimum length of pipe} = \frac{4200}{47 \times 0.08227} = 108 \text{ ft} \quad (7.21)$$

Again, the weight of any additional equipment (drilling motors etc.) is left as a safety margin. Some time before the pipe light point is reached, enough kill-weight mud is pumped down the annulus to

just balance the well. To estimate the amount of kill mud required to balance the well in this case, assume that 18-ppg kill mud is used. The height of kill mud needed is then

$$\text{Height of kill-weight mud} = \frac{137}{(18 - 11.6) \times 0.052} = 412 \text{ ft} \quad (7.22)$$

This means that the theoretical volume of mud to pump, if the drill pipe is at the surface, is

$$\text{Mud volume} = 412 \times \frac{6.625^2 - 4^2}{1029} = 11.2 \text{ bbl} \quad (7.23)$$

The advantage to using this mud weight for kill mud is that not much is required. The disadvantage is that, to correctly balance the well, exact measurements are required. On the other hand, if 16 ppg is used for kill mud,

$$\text{Height of kill-weight mud} = \frac{137}{(16 - 11.6) \times 0.052} = 599 \text{ ft} \quad (7.24)$$

The height of mud needed to balance the well is 599 ft. The volume then required to balance the well is

$$\text{Mud volume} = 599 \times \frac{6.625^2 - 4^2}{1029} = 16 \text{ bbl} \quad (7.25)$$

This means that a small error in fluid measurement is not as critical, so the operation is more forgiving. The downside is that more mud is required. In practice, when dealing with low surface pressures (< 200 psi), it is often more convenient to use lower mud weights for kill mud. When operating at higher pressures, heavier kill mud is usually the best choice. Whatever the kill-weight mud used, when the appropriate volume is pumped, the pressure is checked to make sure the well is dead.

The rate at which the increased hydrostatic pressure from the kill mud reduces the surface pressure decreases as the well gets closer and closer to balance, since the flow into the fracture is a function of the pressure differential. Therefore, quite often, annular pressure is still

observed at this point. This pressure usually decreases with time and eventually goes to zero, if there is no reservoir fluid in the annulus to migrate up and start increasing it again; but even if it does, the time required is often unacceptable with the cost of today's drilling operations.

It is normal practice to pump small additional volumes of kill mud as needed to more quickly take the pressure to zero. A problem that now arises is that the gauges used to read surface pressure are neither precise nor accurate enough to read exactly zero nor do the gauges normally used read a vacuum. Once the annular pressure drops below what the gauge reads accurately, usually 10–50 psi, if the well is opened up, it will flow, allowing influx from the formation and thus increasing instability in the system.

The solution is to install a “tattletale” on either the choke or kill lines that leads to a $\frac{1}{4}$ -in. to $\frac{1}{2}$ -in. hose or tubing, as shown in Figure 7.3. When the needle valve used to control flow to this line is cracked open slightly, even the slightest pressure or vacuum can be detected, either by placing a finger over the end of the line or by using a “bubble bucket,” as when detecting flow with drill-stem tests. The beauty of this system is that it is very easy to rig up, is inexpensive, requires no calibration, and detects pressures of much less than 1 psi, both positive and negative. The movement of the fluid level in the annulus displaces the air above it whenever it moves even slightly; so if the fluid level starts to rise, it can be detected long before it becomes flow at the surface. This has the

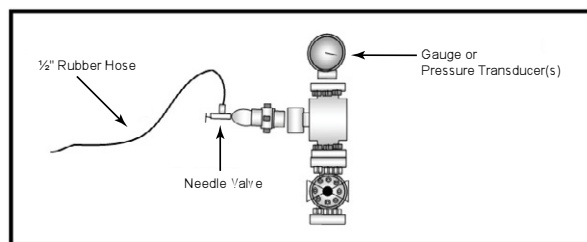


Figure 7.3 Tattletale used to detect the flow during floating mud cap operations.

advantage over an acoustic fluid-level gun of revealing not where the fluid level is but whether or not it is changing, a much more valuable piece of information from a well-control standpoint. The tattletale should be used to confirm exactly what the well is doing before removing the element from the rotating head.

Once the well is stable with no pressure on it, the element is removed from the RCD. If the correct volume of mud was pumped, the fluid level in the well is below the RCD and falling slightly, even if that cannot be readily detected. If the fluid level is so low as to be barely visible, as the remainder of the drill string is pulled from the well, the hole should be filled with light annular fluid. If the fluid level is very near the surface, fill the hole with kill mud while removing the remainder of the drill string, as long as the fluid level remains visible. After the bit clears the blind rams, the well is shut in while the BHA is changed.

When everything is ready to go back into the hole, check the casing pressure gauge. If any pressure is detected, pump in kill mud until it is zero. If the gauge reads zero, also check the tattletale. If there is any blow, however slight, pump kill mud into the annulus. Again, the objective is to exactly balance the well, so if the blow is slight, the amount of kill mud pumped should be small. When there is absolutely no pressure on the well, open the blind rams and run the pipe back into the hole. Once the BHA has cleared or enough pipe has been run to avoid pipe light conditions at anticipated pressures, install the seal element into the RCD and strip in the hole.

While tripping into the hole, if the well has been balanced very closely, the drill string usually displaces mud as it is run in. The kill mud should be recovered this way. As the kill mud is recovered, the well will try to flow, so the volume of the return mud should be closely monitored. If the return volume exceeds the volume of the pipe run in, regulate the choke to prevent this from happening. If some influx does occur, closing the choke completely and continuing to run in has the same effect as pumping in the kill line and can be used to displace the influx back into the formation.

When the pipe is back on the bottom, if everything has been done correctly, the casing pressure is back where it was before the trip. If the pressure is higher, restore it by pumping light annular

mud down the kill line. If not all the kill mud was recovered, the surface pressure is lower than before. If some pressure exists and it is high enough to be reliably measured with the gauges on hand, drilling can resume using this lower annular pressure as the baseline. If no casing pressure exists, it may be necessary to displace the annulus with light annular mud until the kill mud has been displaced into the formation and positive pressure has been restored.

7.6 Conclusion

- Mud cap drilling is a time-tested technique to safely penetrate formations difficult or impractical to drill with other methods.
- The technique is applicable only in highly fractured or vugular carbonate formations that easily accept or flow whole mud. These are also the only formations for which it is required.
- Large volumes of sacrificial drilling fluid are required.
- Specialized equipment requirements are minimal.
- More recent advances, such as pressurized mud cap methods, reduce annular fluid requirements and allow constant monitoring of what is happening downhole, making it safe for use with H_2S .
- The required calculations are minimal and simple.
- The ability to penetrate large intervals impractical to drill otherwise more than offsets any formation damage caused.

Questions

1. When is mud cap drilling appropriate and when should it not be used?
2. How far can drilling continue utilizing mud cap techniques?
3. What if the vugs or fractures plug while drilling using a mud cap?
4. What prevents the drill string from sticking, since the cuttings are not circulated out?

5. Why go to all the trouble of trying to exactly balance the well, especially on trips? If a little heavy mud works, then a lot should work better—right?
6. What modifications to the BOP stack are necessary?
7. What daily fluid volumes are required?
8. What if the well starts flowing when the RCD element has been removed while tripping?
9. Does the situation in question 8 cause formation damage?

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Answers

1. Mud cap drilling is to be used only when a virtually limitless supply of sacrificial drilling fluid is readily available and a highly fractured or vugular formation is being drilled that readily accepts fluid with minimal restriction. If the mud losses can be readily cured with lost circulation material, then mud cap drilling probably is not a good choice.
2. Drilling can continue as long as desired with mud cap drilling. In many cases, it has continued for several thousand feet with no problem.
3. If the vugs or fractures taking fluid plug, then drilling can continue using conventional circulation. It can be easily calculated from the drill-pipe pressure when the injection pressure increases enough to support the ECD of the circulating mud weight required to balance the first fracture. When this happens, the mud weight can be increased and circulated, the flow line opened to the shale shakers, and normal circulation

resumed. If additional fractures are encountered and losses occur again, mud cap drilling can be resumed. By drilling with a pressurized mud cap, switching back and forth as dictated by hole conditions is simple.

4. Pump rates should be maintained at a high enough rate to clean the hole, even though there are no returns at the surface. Modeling can help predict what these rates should be, and since ECD-induced losses are no longer a problem, even higher pump rates than predicted can be used to make sure that hole cleaning is not an issue. The cuttings are actually being removed from the hole, just not returned to surface. In practice, a stuck pipe is very seldom a problem so long as adequate pump rates are maintained.
5. When excessive heavy mud is pumped, for example, to kill the well on a trip, the fluid level falls farther and this increases the difference in balance between the first and last fractures to open. This difference means that, when the well does flow again, and it is only a matter of time until it does, its response also is more sudden and forceful than if it were balanced exactly. By minimally balancing the well, the percentage of mud in the annulus between the first and last fractures is lower and the percentage of formation fluid higher. This also brings the entire well closer to balance, making it more stable, so that it stays balanced longer, and when it does flow again, it does so gradually and with more warning.
6. No modifications are necessary, but a couple of things are suggested. Since quite a bit of pumping is taking place down the kill line at low pressures, it is convenient to either replace the check valve normally present with another manual valve or, better yet, a hydraulically controlled valve, such as an HCR valve. This allows pressure monitoring on both the choke and kill lines. If local regulation or company policy prohibits removing the check valve, it is not necessary, merely convenient. In any case, it is recommended that there be at least two operable valves on the kill line.

7. It is simple to determine the volume of sacrificial fluid needed. For the maximum that could be needed, assume that the drilling pump rate is maintained for an entire 24-hr period. In the example, this is

$$225 \times 60 \times \frac{24}{42} = 7714 \text{ bbl/day}$$

Estimating the annular fluid requirement is somewhat more complex. Gas migration rates ranging from 400 to 5400 ft/hr have been observed, depending on viscosity, difference in density, solubility, and the like. A commonly used rule of thumb has been a migration rate of 1000 ft/hr. If that is the case, then the daily annular fluid requirement while drilling for the example, assuming that 1100 ft of drill collars are used, is

$$1000 \times 24 \times (6.5^2 - 4.75^2)/1029$$

Note that, when using pressurized mud cap methods, the annular injection requirements may be substantially less than this calculation predicts, since annular fluid viscosity may be managed to reduce the migration rate. If the reservoir fluid is oil, migration rates also are much less than those for gas.

8. As in other types of drilling, if the well starts to flow while tripping, that flow should be controlled. Since the element is removed from the RCD only when the bit is near the surface, the foremost consideration is to avoid pipe light conditions. If only one stand or less of BHA is in the hole, the remaining pipe should be immediately pulled and the blind rams closed. If more pipe than can be pulled at once remains in the hole, the shut-in procedure should be slightly different than is often followed. Instead of stabbing a TIW valve or inside BOP, the *preferred first step is to stab and make up the top drive before closing the blowout preventers*. Top drives typically weigh 40,000–50,000 lbs; so using the calculations for pipe light conditions with the BHA in the example, if only four joints of drill pipe are in the hole when the well starts to flow and the top drive is stabbed and made up, the pressure required to be pipe light is at least

$$\frac{40,000 + (4 \times 30 \times 14 \times 0.8227)}{\left(31,416 \times \frac{5.25^2}{4}\right)} = 1911 \text{ psi}$$

By stabbing the top drive first, developing pipe light conditions is extremely unlikely, especially before the pipe rams can be shut. If pressurized mud cap techniques are employed and proper contact with the annular fluid is made, the flow is very slow at first and plenty of time is available to respond without ever coming close to becoming pipe light. If desired, the entire string can be stripped out and in through the RCD, although this decreases seal element life.

9. At first glance, it would appear that the loss of sacrificial fluid and cuttings generated by drilling into the formation would cause substantial damage. No doubt, no matter how a well is drilled, some formation damage occurs. In the types of reservoirs suitable for mud cap drilling, the assumed formation damage is less serious than in other types of reservoirs. Also, remember that there are currently really no good alternatives to drilling these types of formations. It goes without saying that penetrating the entire reservoir section is far preferable and more productive than penetrating only a portion of it. Even if the fractured zones are somewhat damaged by drilling and losing fluid and cuttings into them, that they are open to production when they otherwise would not be means the wells are more productive than if they were not drilled.

The other main point to consider is that the fractures and vugs present in wells drilled using mud cap techniques are quite large and not only less likely to be damaged by fluid and cuttings but, even if damaged, still retain huge flow capacity. Initial production rates historically have not been noticeably impaired by this damage when compared to offsets drilled underbalanced. Reduced connectivity to surrounding microfracture systems has been suspected but difficult to positively identify and quantify.

Finally, the formations for which mud cap drilling is applicable are almost always carbonates, which are not susceptible to the same imbibition and clay swelling fluid damage mechanisms that affect matrix permeability in a sandstone. In short, the production benefits of mud cap drilling far outweigh any formation damage incurred.

CHAPTER EIGHT

Dual-Gradient Drilling

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Roger Stave, AGR Subsea,
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About This Chapter

This chapter is organized a bit differently than other chapters in this book. It is split into four parts. The first part (Sections 8.1 and 8.2) describes why conventional technology is inadequate to address new challenges encountered in the marine drilling industry and how dual-gradient techniques can address these new challenges. The second part (Sections 8.3 and 8.4) describes the AGR dual-gradient operating systems available at the time of this publication. The third part (Section 8.5) describes basic research regarding DG systems. Section 8.6 discusses the theory and challenges of well kicks and well control as they generally affect dual-gradient systems.

8.1 Introduction

Dual-gradient drilling (DGD) refers to offshore drilling operations where the mud returns do not travel through a conventional, large-diameter drilling riser. The returns are either dumped at the seafloor (pump and dump) or returned back to the rig, from the seafloor,

through one or more small-diameter return lines. “Pump and dump” and “riserless muds return” are methods of DGD that can be presently used to drill the top-hole section of offshore wells.

Beyond the surface casing, the present DGD techniques are to return the mud to the rig through small-diameter return lines. A seafloor or mud-lift pump takes returns from the well annulus at the seafloor and pumps it back to the surface. By adjusting the inlet pressure of the seafloor pump to near seawater hydrostatic pressure, a dual-pressure gradient is imposed on the well-bore annulus, much the same way riserless drilling imposes the seawater hydrostatic pressure in the annulus of the well.

As can be seen in Figure 8.1, the seafloor pump reduces the pressure imposed on the shallow portion of the well, while the higher-density mud below the seafloor achieves the required bottom-hole pressure to control the formation pore pressure. The high mud density is imposed on a shorter vertical distance, while above the seafloor, seawater hydrostatic pressure is imposed.

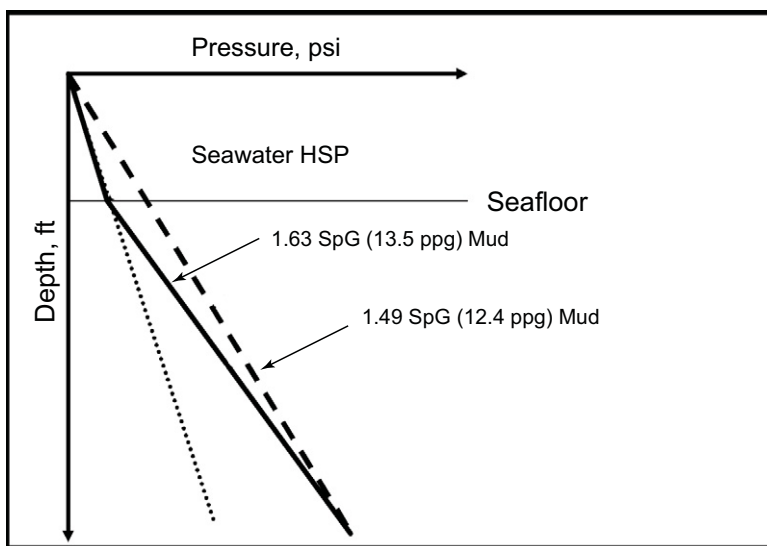


Figure 8.1 The conventional single-gradient versus dual-gradient concept.

8.2 Problems Associated with Conventional Riser Systems in Deep Water

The problems associated with conventional riser drilling in ultra-deep water have been discussed by several authors (Gault, 1996; Choe and Juvkam-Wold, 1997a, 1997b, 1998; Peterman, 1998; Choe, 1999; Schubert, 1999; Schubert, Juvkam-Wold, and Choe, 2006). The deeper the water, the more joints of required marine riser must be loaded onto the vessel and brought to the location. This results in deck space and loading-capacity limitations, especially for smaller or older vessels. An additional barge can be utilized to transport the riser to the location, but this does not account for periodic retrieval of the riser due to storms, emergency disconnect, or pulling of the blowout preventer stack for repairs. Not only is deck space a problem, only a handful of the world's floating rig fleet can support the tremendous deck loads imposed by the extremely long risers required for drilling in ultradeep water.

These extremely long risers require large volumes of drilling fluid just to fill them, as much as 3700 bbl for a 10,000-ft long, 19.5-in. inside diameter riser, costing well over \$400,000 for synthetic-based drilling fluid. Not only is the cost high, but the volume of mud to fill the riser may be much greater than the storage capacity of the rig itself.

In addition to logistical challenges encountered when handling a drilling riser, reaching the geological objectives becomes more difficult as water depths become greater with a conventional mud-filled riser system. Geologic targets tend to be deeper below the mud line in deep waters, resulting in additional casing strings. Not only do the deep targets increase the number of casing strings required, but the effective window between the pore pressure gradient and fracture pressure gradient narrows with increasing water depth. The narrow window also increases the frequency of casing points. With the current marine risers, an operator can quickly run out of usable hole size before the geologic objectives are met.

Figures 8.2 through 8.6 demonstrate the effective narrowing of the pore/fracture gradient window as water depth increases and how the number of casing strings required to reach total depth increases.

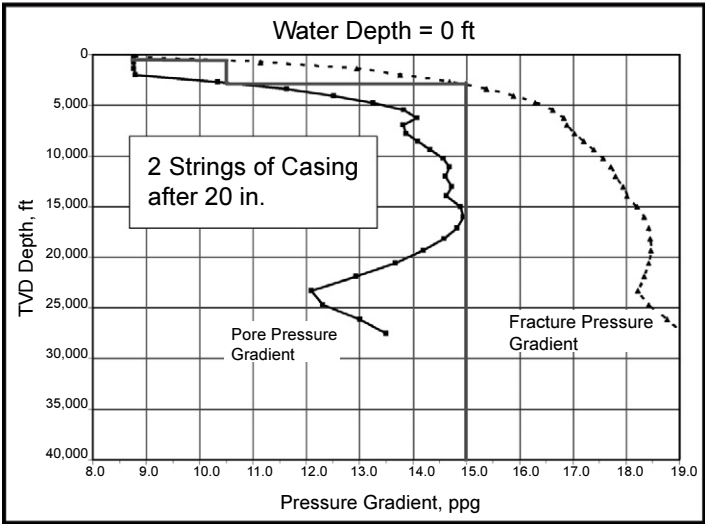


Figure 8.2 Pore pressure and fracture pressure for an abnormally pressured land well with postsurface casing points.

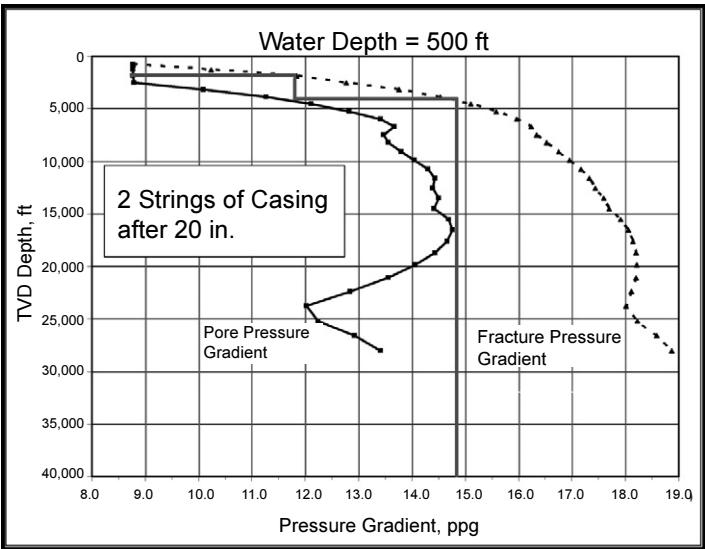


Figure 8.3 Pore pressure, fracture pressure, and casing points for a well in 500-ft water depth.

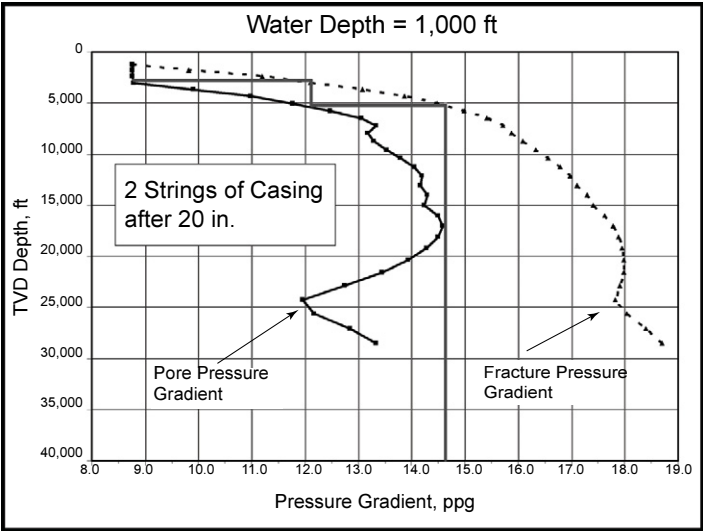


Figure 8.4 Pore pressure, fracture pressure, and casing depth for 1000-ft water depth.

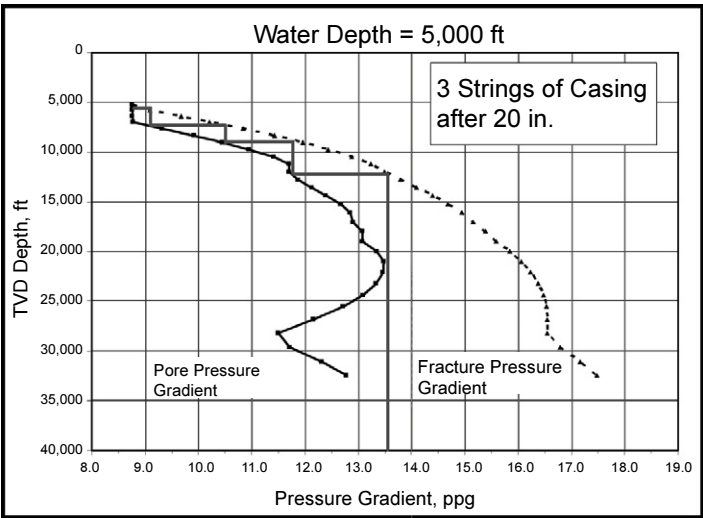


Figure 8.5 Pore pressure, fracture pressure, and casing depth for 5000-ft water depth.

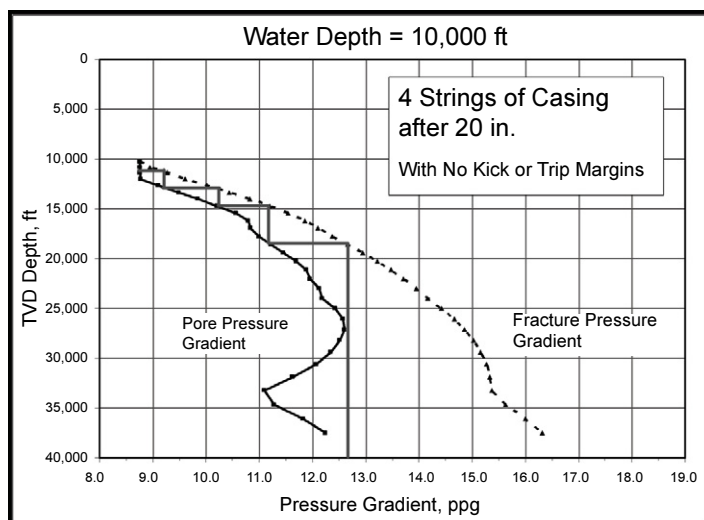


Figure 8.6 Pore pressure, fracture pressure, and casing depth for 10,000-ft water depth.

Figure 8.2 shows the pressure gradients for an abnormally pressured formation drilled from the land or in shallow water. The only difference between Figure 8.2 and Figures 8.3–8.6 is that the pore and fracture pressure are increased by the seawater hydrostatic pressure and the pressure gradients are recalculated with respect to the new water depth.

Figure 8.7 has the same plot as Figure 8.6, with the addition of the pore and fracture gradients for the same well drilled with a dual-gradient system. The difference is created by how the pressure gradients are calculated. Conventional riser drilling calculates all pressure gradients with respect to the rotary kelly bushing, while DGD pressure gradients are calculated with respect to the seafloor. What should be evident from this figure is that DGD widens the pore/fracture gradient window, removing the problems associated with the narrow window usually associated with ultradeepwater drilling. Also note, the DGD pore pressure and fracture pressure at 10,000-ft water depth are the same as the land well in Figure 8.2. This means the same mud densities could be used to drill both wells.

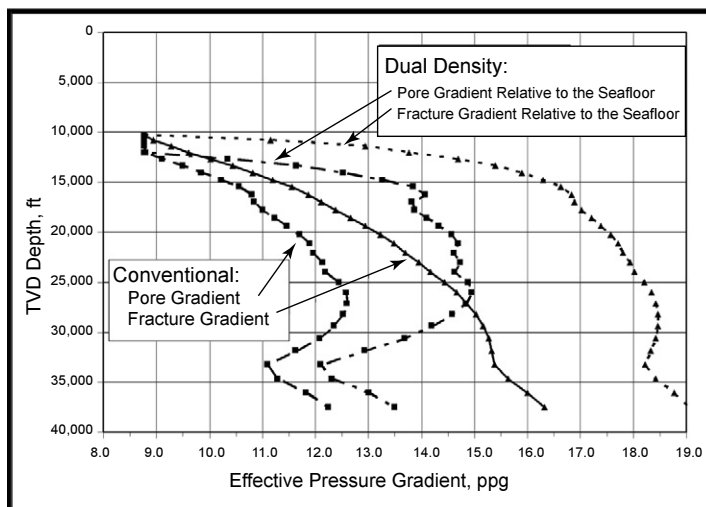


Figure 8.7 Comparison of DGD pore and fracture gradients calculated from the seafloor to conventional ones calculated from the sealevel in 10,000-ft water depth.

The widening of the pore/fracture gradient window allows the operator to reach the total depth with fewer casing strings and a larger final well-bore size. Figure 8.8 compares predicted casing depths for the same pore/fracture gradient window, one using conventional deepwater drilling and one using DGD. As is demonstrated by Figures 8.2–8.8, the typical narrowing of the pore/fracture gradient window as a result of increasing water depth results in necessary additional casing strings to reach total depth. DGD gives the operator a wider window, and fewer casing strings are required to reach the total depth. This is critical, not only from the time and cost standpoints of the additional casing, but also because it allows larger production casing to be run, which prevents the production rate from being choked back by small production tubing. The greater window also allows the operator to plan the well with sufficient trip and kick margins.

Most of the problems associated with the conventional marine riser can be either minimized or eliminated with the dual gradient achieved through the use of the mud-lift principle. The same authors who

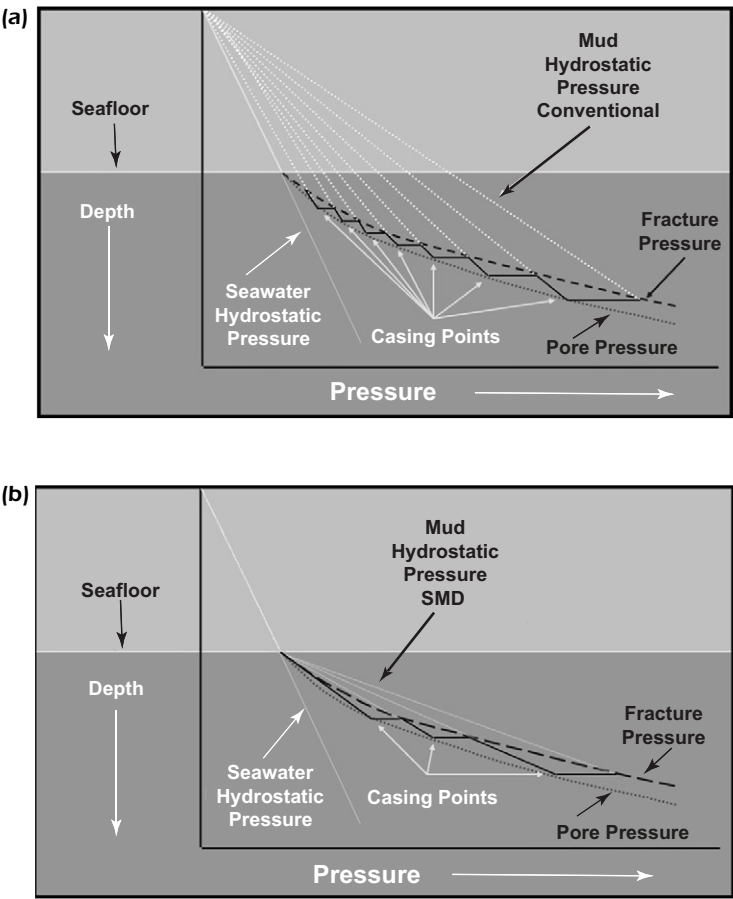


Figure 8.8 Casing points: (a) conventional deep water; (b) dual gradient.

point out the problems associated with conventional riser systems, also discuss advantages of the dual-gradient system (Gault, 1996; Choe and Juvkam-Wold, 1997a, 1997b, 1998; Peterman, 1998; Choe, 1999; Schubert, 1999; Schubert, Juvkam-Wold, and Choe, 2006). Three logistical advantages to using DGD are less deck space required for the small-diameter (6-in. outside diameter) return line, smaller deck loads, and less drilling mud required to drill a well. DGD also allows for smaller second- and third-generation floating rigs to be upgraded to drill in deeper water. This would increase the rig availability for

deepwater drilling. Additionally, the ability to meet geologic objectives with fewer casing strings, allowing a larger, optimized-diameter production tubing, allows the well to produce at high rates, which in turn can make the wells more economically attractive. This can also reduce drilling costs by reducing plateau times while drilling a well.

Although DGD drilling can minimize or eliminate many of the problems associated with conventional riser drilling, there is one significant disadvantage to the implementation of this unconventional system. The technique of DGD is still mostly untried at this time and needs to undergo a considerable amount of research and development.

8.3 AGR Riserless Mud Return System

Much of the research and most of the publications on DGD concern the use of this technology only after the surface casing is set. However, AGR Subsea AS, with its riserless mud return system, is using the technology in the top-hole portion with great success. The advantages of using DGD on the top hole are explained in several publications (Judge and Thethi, 2003; Stave et al., 2005; Elieff, 2006; Elieff et al., 2006).

8.3.1 Introduction

Riserless mud return (RMR™) is a top-hole drilling system that uses a subsea pump to return drilling fluid from the seafloor to the drilling vessel and is the first dual-gradient drilling system commercially available. This system has many advantages over conventional top-hole drilling techniques, including the use of engineered drilling fluids, capacity to drill in environmentally sensitive areas, ability to extend casing setting depths, elimination of intermediate liners, and better well-bore stability.

A computer control system adjusts the speed of the subsea pump based on a pressure set point measured at the wellhead, as can be seen in Figure 8.9. This subsea pump automatically pumps all the returns to the surface and maintains a constant well-bore pressure. Since the pump is automatically controlled, it responds to drilling

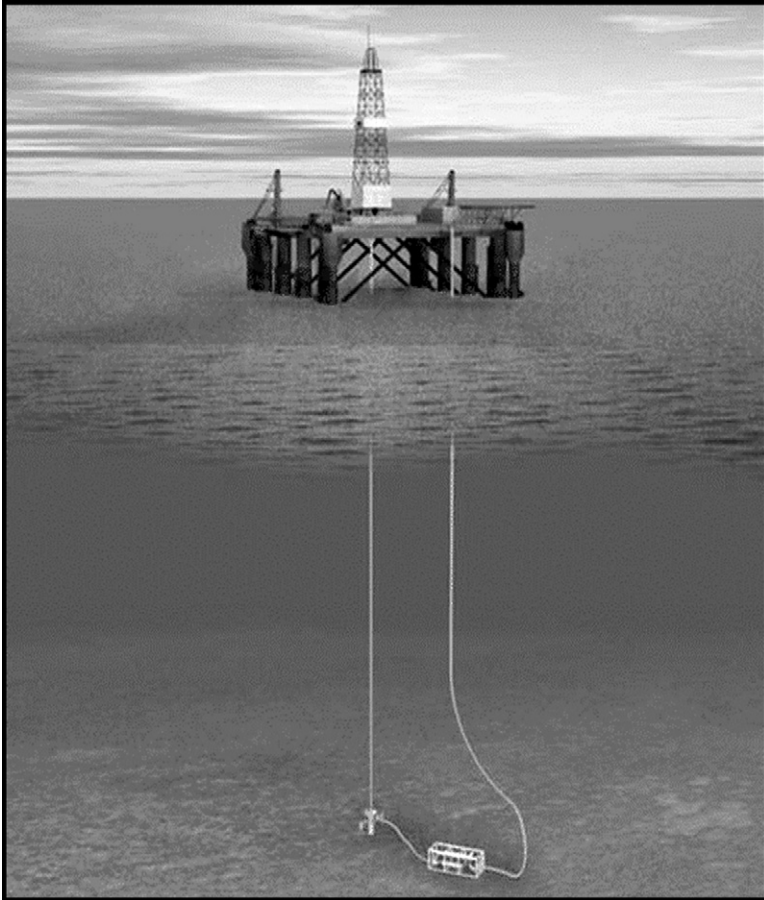


Figure 8.9 The RMR system.

situations without operator intervention. This simplifies drilling while maintaining improved well-bore stability.

8.3.2 Primary Uses

The primary reasons to use RMR are:

1. To allow the use of an engineered mud system with a density higher than seawater and avoid the cost of pumping and dumping returns to the seabed.

2. To introduce volume control and kick detection for the top-hole sections.
3. To avoid pollution in environmentally sensitive areas, where pumping and dumping returns to the seabed may cause damage.

The RMR system is used in areas where the top-hole formations present difficult drilling conditions that either prevent the well from being drilled, severely limit the depth to which the casing can be set, or result in high costs due to the loss of drilling fluid in a pump and dump condition. Additionally, the RMR is used in environmentally sensitive areas, where dumping the drilling fluid is not acceptable because of regulations or harm to the environment. RMR is a closed-loop system, which means zero discharge to the environment. RMR solves these problems by returning all the drilling fluid back to the surface, where it can be reconditioned and reused.

8.3.3 Equipment

The RMR system consists of six main components:

1. Suction control module.
2. Subsea pump.
3. Deployment.
4. Power supply.
5. Control module.
6. Return conduit.

Suction Module

The suction module (SMO) attaches to the wellhead, and different models are provided for different wellhead models. The SMO provides a connection point for the subsea pump, and a pressure transducer is located near the pump connection point. The SMO also provides access to the well for the drill pipe and a mud/seawater interface. The interface is monitored with video cameras mounted on the SMO. Also, the SMO can be run to the wellhead on drill pipe or cables. Figure 8.10 shows an SMO being prepared for launch.



Figure 8.10 The wellhead component of the RMR system.

Subsea Pump

A proprietary disc (friction) pump (Figure 8.11) is used to lift the drilling fluid and cuttings from the seafloor to the drilling vessel. Like the SMO, it is capable of several different configurations and can be set on the seafloor or suspended from the deployment umbilical. The latter deployment can be used to compensate for rig heave by using a service loop in the suction line.

The pump uses a special impeller composed of discs with minimal profile. Pumping is achieved through the friction between the high-

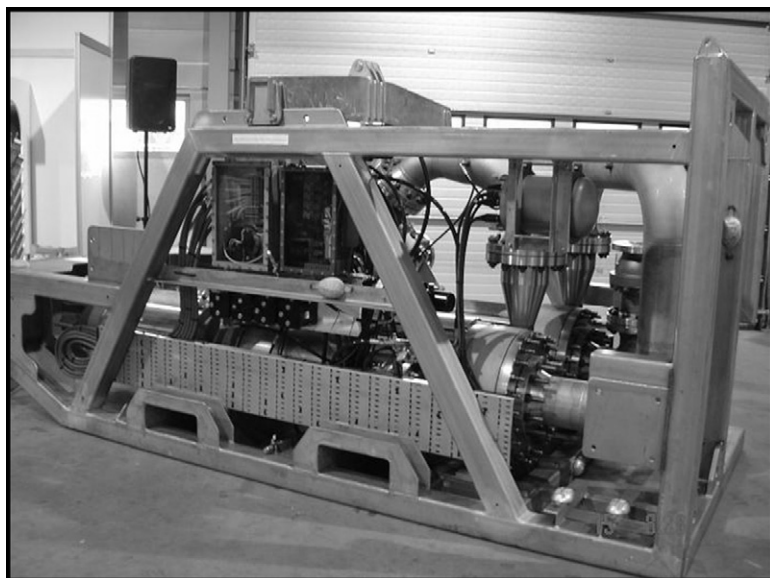


Figure 8.11 RMR two-stage pumping unit.

speed spinning discs and the fluid. This type of pump has excellent wear resistance when pumping abrasive media and can tolerate solids up to 3 in. in diameter in the current design. Additional head can be achieved by running pumps in series. This type of pump has the ability to hold a column of mud at a fixed level in the return line in a quasi-static condition. Returns from the pump are directed to the return line, which can be either special soft hose assembled in sections or a steel riser. The suction line that connects the subsea pump to the SMO is equipped with an ROV-friendly low-pressure flange connection. A control line also deployed by the ROV provides power and completes the data connection from the pump to the SMO.

Deployment

The deployment is a separate unit designed to mount on the edge of the drilling vessel to allow direct access to the sea. The pump is attached to the deployment through the umbilical. Power lines and fiber-optic lines are integral within the deployment line. The power

supply and control module provide power and control to the deployment.

Power Supply

A power supply module conditions and distributes all necessary power to the RMR system. A variable-frequency drive powers the subsea pump and allows precise speed control. The deployment and control module are also powered from this supply.

Control Module

The control module has the necessary hardware and software to control the operations of the RMR system. It has the operator and driller interfaces, so that accurate information is recorded and passed on to monitor the operations of the system. It includes diagnostic information on the pump, so that any problems can be detected and action taken to resolve the problem.

8.3.4 Operation

The RMR system uses a computer to control the speed of the subsea pump, based on a suction-pressure set point that is monitored by the pressure transducer on the SMO. Once the RMR equipment is in place and drilling begins, the system is started by observing the drilling-fluid/seawater interface using the video cameras on the SMO. This interface is easily seen, and once observed, the pressure measured by the transducer on the SMO can be entered as the set point for the suction control pressure. The computer control system adjusts the speed of the pump to keep the suction pressure constant. Any change in this pressure causes the subsea pump to speed up or slow down to compensate. Experience has shown that changes as little as 1 cm in the drilling-fluid/seawater interface causes the pump to change speed. This is the key to the operation of the RMR and is what allows it to compensate for almost any change in the drilling operations.

Well Kicks

When a kick, fluid from the formation, enters the well bore, the RMR system gives an early kick indication, because the pump speeds up to move the additional fluid. Based on the control module set-

tings, this sets off an alarm and alerts the operator. The mechanism that triggers this is very simple. The additional fluid raises the interface between the drilling fluid and the seawater, which causes the suction pressure on the pump to change. The transducer measures this change and the computer adjusts the pump speed to return the pressure to the set-point value. Once the fluid influx is detected, the mud weight may be increased to increase the bottom-hole pressure and prevent further kicks from entering the well bore.

Connections and Trips

The RMR pump remains running during connections. Once the rig pumps are stopped, the fluid in the drill pipe U-tubes due to the imbalance of density between seawater and drilling fluid. As the fluid stops U-tubing, the computer control slows the pump to idle, where it is just supporting the fluid in the return line. Once the connection is made and the rig pumps restarted, the RMR pump speeds up and continues as before, pumping the fluid to the surface.

An alternative is to use a drill-string valve (DSV) with a spring strong enough to support the column of drilling fluid in the drill pipe. In this case, once the rig pumps are stopped, the RMR pump slows and simply supports the column of mud in the return line.

When tripping into the hole, the RMR pump is in idle mode until the suction module on the annulus begins to displace mud. Then, the pump increases speed to remove the displaced volume of mud.

When tripping out of the hole, mud is pumped into the well to replace the volume of the drill pipe. The computer control keeps the suction pressure at the same set point, and therefore, the bottom-hole pressure remains constant as well.

Surge and Swab Pressures

The ability of the disc (friction) pump to quickly change speed compensates for surge and swab, keeping the bottom-hole pressures constant.

Shallow Gas

Shallow gas and drilled gas are allowed to escape the well from the open top in the SMO. The cameras mounted on the SMO can be

used to qualitatively monitor the amount of gas escaping the well, as it can be seen as it bubbles out of the drilling fluid. Large gas influxes result in the pump speed increasing to compensate for the increased flow from the well. Studies have shown that the gas is detected and the pump can be shut off before the gas reaches the pump and return conduit. Shallow-water flows have the same effect, but both these situations have less frequency, because engineered drilling fluids can be employed to prevent or control them.

Pump Surges

During operations the rig pumps should be started and stopped at moderate, uniform, and reasonable ramp rates to allow the RMR control system time to adjust the speed of the pump, which compensates for the changes. Ramping up or down, the rates are not as critical as sudden starts and stops.

8.3.5 Critical Issues

1. A heavy load of gumbo can be discharged from the SMO to the seafloor, even though the disc pump can handle most reasonable gumbo concentrations.
2. The use of heavier muds with the RMR system should significantly reduce the possibility of taking a kick. However, should a major kick occur, the well cannot be shut in, and the kick is automatically discharged to the sea.
3. High currents or excessive vessel movements can tangle the RMR return line with the drill string or cause a crash between the pump and drill sting.
4. The RMR system must have sufficient power from the rig to operate the pump, electronics, and deployment.
5. Depending on the required mud weight and mud volume, the pump must be appropriately matched in power to support rig operations. In some cases, this may require a multistage pump.

8.3.6 Summary

The RMR is a true dual-gradient drilling system that can solve many challenges typically encountered when drilling the top-hole

section of a subsea well. In addition, the RMR provides the only current means of drilling in environmentally sensitive areas without causing excessive pollution.

8.4 AGR Dual-Gradient System

8.4.1 Introduction

The AGR dual-gradient system is a drilling system for use with a riser, which uses subsea pumps to return drilling fluid from near the seafloor to the drilling vessel, as shown in Figure 8.12. Using the sub-sea pump to return the drilling fluid allows the drilling riser to be filled with a blanket fluid that is lighter in density than the drilling fluid. This has many advantages over conventional drilling techniques, including the use of heavier and more expensive engineered

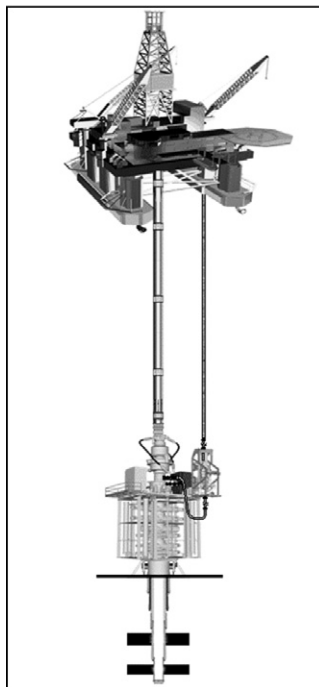


Figure 8.12 The dual-gradient system.

drilling fluids, the ability to extend casing setting depths (eliminate intermediate casings), improved well-bore stability, reduced formation damage, and better well control.

A computer controls the speed of the subsea pump based on suction pressure measured at the wellhead. Changing the set point for the suction pressure allows a variable head of drilling fluid in the riser, while still pumping all the returns to the surface. Since the pump is automatically controlled, it responds to changes in drilling parameters without operator intervention, to keep a constant bottom-hole pressure, simplifying drilling and maintaining improved well-bore integrity.

8.4.2 Primary Uses

The main advantages of using this system are:

1. To allow dual-gradient density drilling with a riser, which permits the use of engineered mud systems with greater density than typically used in conventional drilling techniques.
2. To improve control of bottom-hole pressures and equivalent circulating density, which prevents damage to critical producing formations.
3. To extend casing depths beyond those typically possible with conventional drilling systems.
4. To provide a technically competent method of maneuvering in the narrow formation-pore/fracture gradient window.

This system is used in deepwater wells to avoid excessive numbers of casing strings and ultimately allow for the largest possible production tubing to be installed to permit the economic retrieval of resources.

8.4.3 Equipment

The system consists of seven major components:

1. BOP stack suction-line attachment point.
2. Subsea pump.
3. Return conduit.

4. Deployment.
5. Blanket fluid circulating system.
6. Power supply.
7. Control module.

BOP Stack Suction-Line Attachment Point

The pump attaches below the upper annular preventer on the lower marine-riser package (LMRP), as can be seen in Figure 8.13. The attachment point can be integrated in the upper annular preventer or on a short spool below the preventer. A pressure transducer located at this connection point is used to control the operation of the pump. Figure 8.13 shows the pump with the suction line attached to the LMRP.

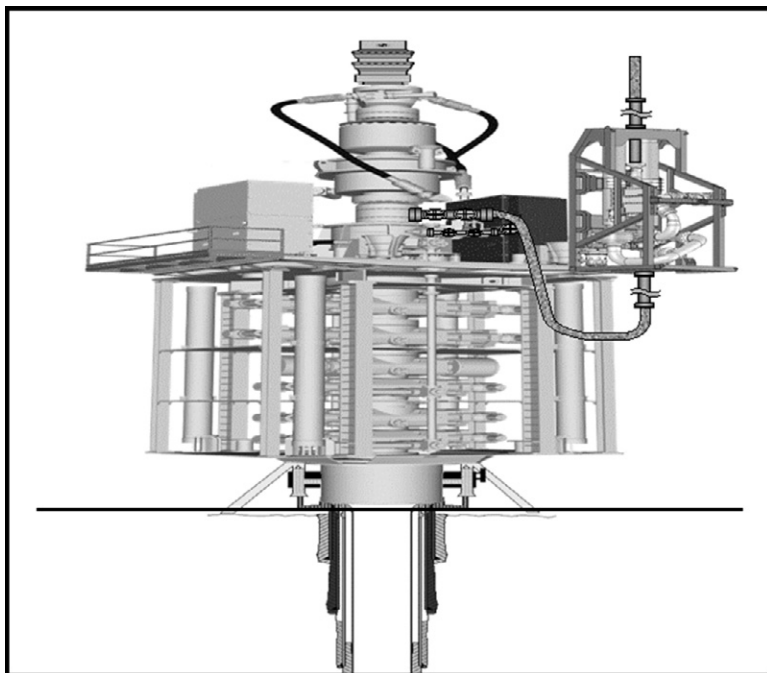


Figure 8.13 The subsea system.

Subsea Pump

A proprietary friction pump is used to lift the drilling fluid and cuttings from the seafloor to the drilling vessel. The pump uses a special impeller, comprising discs with minimal profiles. Pumping is achieved through friction between the high-speed spinning discs and the drilling fluid. This type of pump has excellent wear resistance when pumping abrasive media and can tolerate solids in the fluid without clogging. The current design can pass solids up to 3 in. in diameter. Additional head is achieved by running pumps in series, and this type of pump has the ability to hold a column of mud at a fixed level in the return conduit in a quasi-static condition. Fluids from the pump are directed to the return conduit, which can be either a separate return “riser” or a line on the existing drilling riser. The suction line that connects the subsea pump to the LMRP is equipped with an ROV-friendly flange connection. A control line, also deployed by the ROV, provides power and completes the data connection from the pump to the pressure sensor.

Deployment

The pump is either deployed separately on an independent return “riser” or the pump is attached to the bottom joint of drilling riser just above the LMRP and deployed with the riser. Figure 8.14 shows a pump attached to the bottom joint of the drilling riser.

Power Supply

A power supply module conditions and distributes all required power to the RMR system, and a variable-frequency drive controller powers the subsea pump and allows precise speed control. The deployment and control module are also powered from this power supply.

Control Module

The control module has the necessary hardware and software to control the operations of the system. It has the operator and driller interfaces that allow accurate information to be recorded and passed on to personnel monitoring the operation of the system. It includes diagnostic information on the pump, which allows for any



Figure 8.14 The pump deployed some distance above the BOP stack.

problems or errors to be identified and appropriate corrective actions to be taken.

8.4.4 Operation

The system uses a computer to control the speed of the subsea pump, based on a suction-pressure set point monitored by the pressure transducer at the attachment point between the pump and LMRP. Once the equipment is in place and drilling begins, the system is started by setting the suction control pressure. This set point is calculated to provide the desired bottom-hole pressure. The bottom-hole pressure is determined from the column of blanket fluid and the location, within the riser, of the interface between the drilling fluid and

the blanket fluid. The computer control system adjusts the speed of the pump to keep the suction pressure constant, and any change in this pressure causes the subsea pump to speed up or slow down as compensation. Experience has shown that changes as little as 1 in. in the drilling-fluid/blanket-fluid interface cause the pump to change speed. This is the key to the operation of the system, and this feature is what allows the system to compensate for almost any change in drilling parameters.

Well Kicks

When a kick enters the well bore, the system gives a very early indication as the pump speeds up to pump the additional fluid. This also sets off an alarm for the operator. A simple transducer detects that additional fluid is causing the interface between the drilling fluid and the blanket fluid to rise, thus changing the suction pressure. The transducer measures this change, and the computer adjusts the pump speed to return the pressure to the set-point value. Once fluid influx is detected, the mud weight can be increased to increase the bottom-hole pressure, or the suction-pressure set point can be increased to allow the interface between the drilling fluid and the blanket fluid to rise. Both methods have the same effect: The bottom-hole pressure increases.

Connections and Trips

The pump remains running during connections. Once the rig pumps are stopped, the fluid in the drill pipe U-tubes because of the imbalance between the weight of blanket fluid and drilling fluid. As the fluid stops U-tubing, the computer control slows the pump to idle, where it is only supporting the fluid in the return line. Once the connection is made and the rig pumps are restarted, the pump speeds up and continues as before, pumping the fluid to the surface.

An alternative to this method is to use a drill-string valve with a spring strong enough to support the column of drilling fluid in the drill pipe (Gonzalez, 1998; Gonzalez and Smits, 2001; Oskarsen, 2001). In this case, once the rig pumps are stopped, the pump slows and only supports the column of mud in the return line. After the con-

nection is made and the mud pumps are restarted, the pump automatically speeds up and pumps the drilling fluid to the surface, as before.

When tripping in the hole, the pump is in idle mode until the stack-attachment pressure sensor shows displaced mud, then the pump increases speed to remove the displaced volume of mud. When tripping out of the hole, mud is pumped in to replace the volume of the drill pipe as it is removed from the hole. The computer control keeps the suction pressure at the same set point, and therefore, the bottom-hole pressure also remains at the same fixed value.

Surge and Swab Pressures

The ability of the disc pump to quickly change speed compensates for surge and swab, keeping the bottom-hole pressures constant.

Pump Surges

During operations, the rig pumps should be started and stopped at moderate, uniform, and reasonable ramp rates to allow the RMR control system time to adjust the speed of the pump to compensate for the changes. Pump ramp rates are not as critical as sudden starts and stops.

8.4.5 Critical Issues

1. High currents or excessive vessel movements can tangle the return “riser” with the drilling riser or cause a crash between the pump and drilling riser.
2. The system must have sufficient power from the rig to operate the pump, electronics, and deployment.
3. Depending on the required mud weight and mud volume, the pump must be matched in power to support rig operations. This may require a multistage pump.

8.4.6 Summary

The system is a true dual-gradient drilling system that can solve many challenges typically encountered when drilling in deep water.

It allows for effective and efficient control of the bottom-hole pressure and ECD, thus allowing longer casing runs, reducing the number of casing strings required to complete the well.

8.5 Subsea Mud-Lift Drilling System (Joint Industry Project)

8.5.1 SMD Equipment

As is the case in many new technologies, dual-gradient drilling requires additional equipment not found in conventional deepwater drilling operations (Eggemeyer et al., 2001; Gonzalez, 1998, 2000; Gonzalez and Smits, 2001; Schumacher et al., 2001; K. L. Smith et al., 2001). Figure 8.15 shows the equipment in the circulating system for the subsea mud-lift drilling (SMD) dual-gradient package. The rig's mud pumps displace mud down the drill string, through the bit, and back up the annulus to the seafloor. A subsea rotating diverter (similar to a rotating control device) diverts the mud flow from the annulus to a cuttings processor, which crushes large cut-

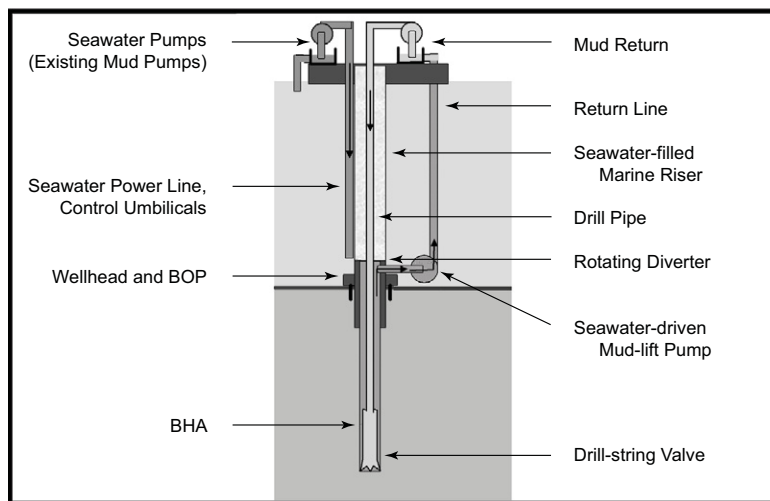


Figure 8.15 The subsea mud-lift drilling dual-gradient system.

tings into a size small enough to pass through the seafloor pump and up the return lines without clogging. After the mud and cuttings pass through the cuttings processor, the seafloor pump displaces the returns up the return line and back to the rig. The cuttings processor developed for the SMD joint industry project (JIP) might not be utilized on all DGD operations, and this determination would be up to the operator.

The reduction in annular pressure by the seafloor pumps results in an active U-tube of the mud from the drill string into the annulus. There are two ways to manage this U-tube effect. Either the rig crew must wait to close the well in until the U-tube ceases, every time the rig pumps are stopped, or a valve, such as a DSV, to arrest the U-tube must be placed in the drill string. This valve opens with circulation and closes when circulation ceases.

The SMD JIP designed and built positive-displacement diaphragm pumps to be placed on the seafloor. These pumps were powered by hydraulic pressure from a seawater pump located on the deck of the vessel. Seawater is pumped down a power line to the seafloor pump. The Shell (Gonzalez, 2000) and Transocean/Baker Hughes Deep Vision (Sjoberg, 2000) projects were other dual-gradient projects conducted at the same time as the SMD JIP. The major differences among the three projects were the pumps. A full discussion of these pumps can be found in Oluwadairo (2007).

8.5.2 The U-Tube Phenomenon with DGD

A major factor in the success of DGD is the active U-tube that is always present (Zhang, 2000; Johansen, 2000; Vera, 2002). To better understand how the U-tube is managed, it is best to start with the very basics. Figure 8.16 shows a conventional deepwater well (riser, drill string, and annulus) depicted as a U-tube, or manometer. For conventional drilling, under static conditions with uniform mud weight throughout the well bore, the hydrostatic head in the drill string and annulus are equal. Therefore, the U-tube is balanced. There are exceptions, however, such as when the mud density is increased, during cementing operations, or when the annulus becomes loaded with cuttings or gas.

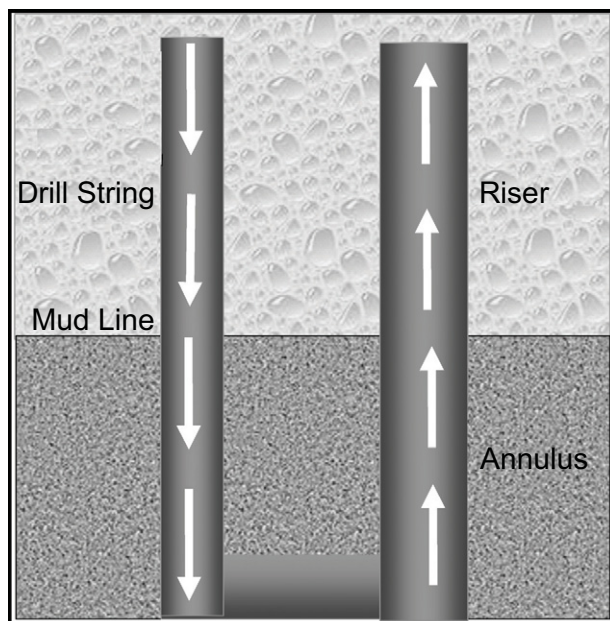


Figure 8.16 The conventional deepwater well depicted as a U-tube.

Figure 8.17 depicts a dual-gradient well with a floating drilling vessel, drill string, well, and return lines on the left side of the figure. The right side of the figure depicts the same well as a U-tube with the mud-line pumps located at the seafloor, pumping mud returns up the return line. The reduction of the annulus pressure at the seafloor to near seawater hydrostatic pressure is represented in the right side of Figure 8.17, which is the cause of the DGD U-tube.

Figure 8.18 shows a diagram and pressure profile of the DGD well under static conditions after the U-tube has stabilized. As can be seen, the fluid level in the drill string has dropped to a level where the hydrostatic head in the drill string is equal to the combined hydrostatic head of the seawater column and the mud column in the annulus. The graph shows equal pressure profiles inside the drill string and annulus below the seafloor. However, the annulus has a pressure increase at the seafloor, maintained by the seafloor pump and the mud pressure gradient in the return line.

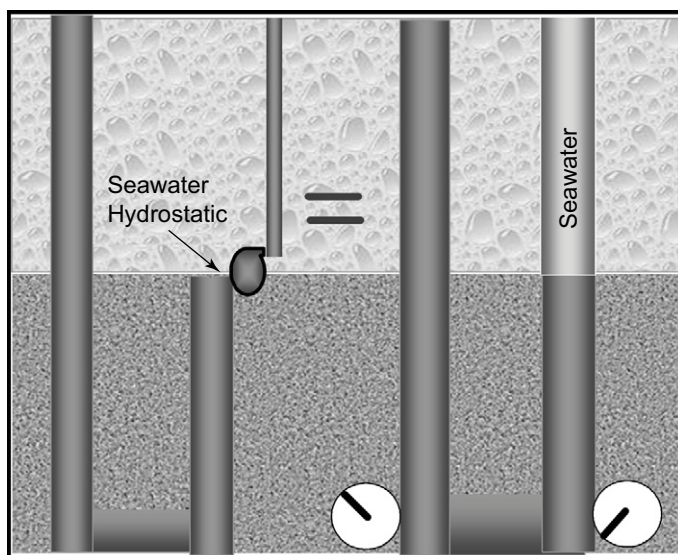


Figure 8.17 The dual-gradient well depicted as a U-tube.

The U-tube effect occurs in a DGD well when the pump is shut down, because the pressure at the inlet to the seafloor pump is maintained near seawater hydrostatic. The final mud level depends on two factors: the relative densities of the fluids (mud and seawater) and the water depth. Below the mud line, the pressures are balanced inside and outside the drill string. Above the mud line, the height of the mud inside the drill string is, in effect, balanced against a column of seawater.

The time required for the U-tube to stabilize depends on the water depth, mud density, mud viscosity, inside diameter of the drill pipe, bit nozzle sizes, and well depth. Zhang and Johansen performed a parametric study of the U-tube (Zhang, 2000; Johansen, 2000). Figure 8.19 is a summary of their findings. The middle column is the base case, while the right column shows the ranges studied.

The graph portion of Figure 8.19 shows the simulated U-tube rate over time for the base case, where the circulation rate is 500

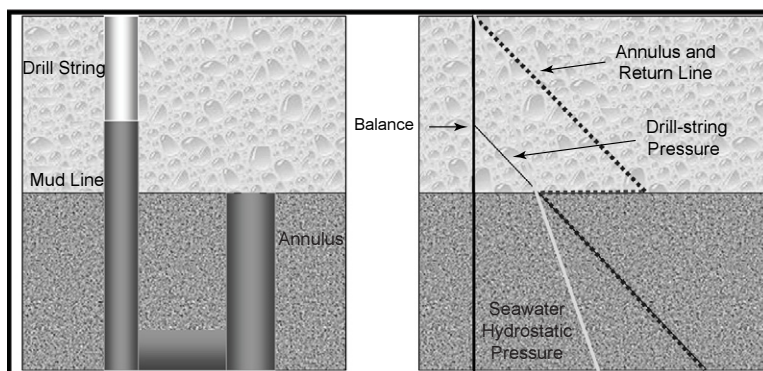


Figure 8.18 The dual-gradient well after a U-tube (left) and the resulting pressure profile (right).

gal/min. When circulation stops, the mud return rate, equal to the U-tube rate, drops to the freefall rate of approximately 400 gal/min. As the fluid level drops, the U-tube rate decreases proportionately. The “hump” in the curve at 10 min is the transition from turbulent flow to laminar flow, as calculated by the software, and equilibrium is reached in 23 min.

Six factors affect the U-tube, but water depth and mud density are the two main driving forces behind the U-tube effect. As both increase, the U-tube rate increases and the final fluid level in the drill pipe decreases. Therefore, the time to reach equilibrium in the drill pipe increases. The other four factors affect only the U-tube rate and the time to equilibrium. An increase in mud viscosity decreases the rate and increases the time to equilibrium. An increase in the inside diameter of the drill string results in an increase in the U-tube rate by reducing the friction pressure. It might be expected that the time to reach equilibrium would increase because of greater volume of mud to drain, but simulations show that this is not necessarily the case. The bit nozzle size, as well as other restrictions in the drill string, affects the U-tube rate and time to equilibrium. As the nozzles increase, the restriction to flow reduces and the U-tube rate increases. Therefore, the time to reach the equilibrium level decreases. The depth below the mud line is the final factor

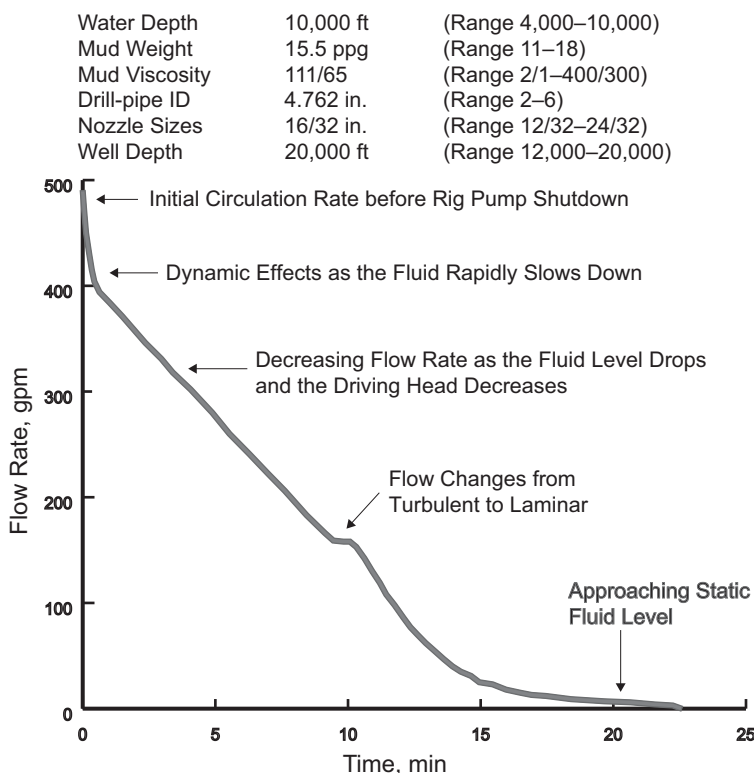


Figure 8.19 A typical U-tube rate of a dual-gradient well over time.

affecting the U-tube rate. As the well depth increases, the U-tube rate decreases because of increased friction pressure and the time to reach equilibrium increases.

The U-tube effect results in an increase in the surface pit level. The potential problem is to determine if the pit gain and continued flow (U-tube) after circulation is stopped are caused by the U-tube only or the U-tube in addition to well flow from a kick. The way to tell the difference is in trend analysis. Modeling the U-tube behavior, plus recording the U-tube trend, during connections can provide “normal” U-tube behavior. If the U-tube rate starts to increase and the calculated and measured U-tube volume increases between subsequent connections, or anytime circulation is stopped, a kick is

indicated. A kick during the U-tube effect also is indicated by the increased time for the U-tube to reach equilibrium. In fact, if a kick is occurring, apparent equilibrium will not be reached. The well simply continues to flow.

The effect of the U-tube can be mitigated with the use of a DSV (Gonzalez, 1998; Oskarsen, 2001; Gonzalez and Smits, 2001). In the DGD JIPs, a valve of this type was designed to open with positive rig pump pressure above a preset amount. When circulation is stopped, the spring-loaded valve closes, stopping the U-tube effect.

This makes operations appear to be very conventional. The valves were designed so that the spring closing force can be adjusted at the surface. The spring force is set based on the water hydrostatic pressure and the anticipated mud density for each specific hole section. This way, the opening pressure of the valve always is greater than the differential pressure between the mud hydrostatic and seawater hydrostatic. Figure 8.20 shows the valve in the open and closed positions.

With the DSV in place, the static pressure profile is as seen in Figure 8.21. Compared to Figure 8.18, there is a pressure differential across the arrestor valve, which shifts the drill-string pressure profile to the right, where it overlays the pressure profile in the return line.

Circulating conditions result in a positive rig pump pressure at all rates with the arrestor. However, with no valve, at circulation rates below the natural U-tube rate, the drill string is not full and no rig pump pressure is recorded.

8.6 Dual-Gradient Well Control

The industry has expressed concern that DGD well control is so complex it will be more difficult to implement and, therefore, make it less safe than conventional deepwater well control. This is simply not true. It is different; but with the controls built into the DGD equipment, in many ways, DGD well control is better than conventional well control (Choe and Juvkam-Wold, 1997a, 1997b, 1998; Choe, 1999; Schubert, 1999, Choe, Schubert, and Juvkam-Wold, 2007; Elieff, 2006; Elieff et al., 2006; Schubert et al., 2006).

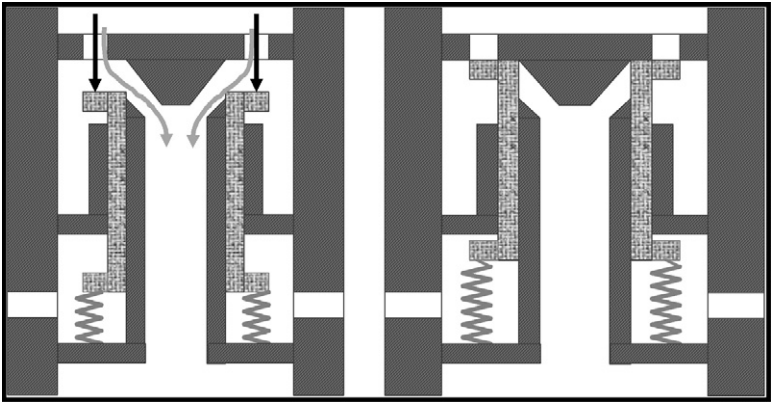


Figure 8.20 The U-tube arrestor valve in the open position (left) and closed position (right).

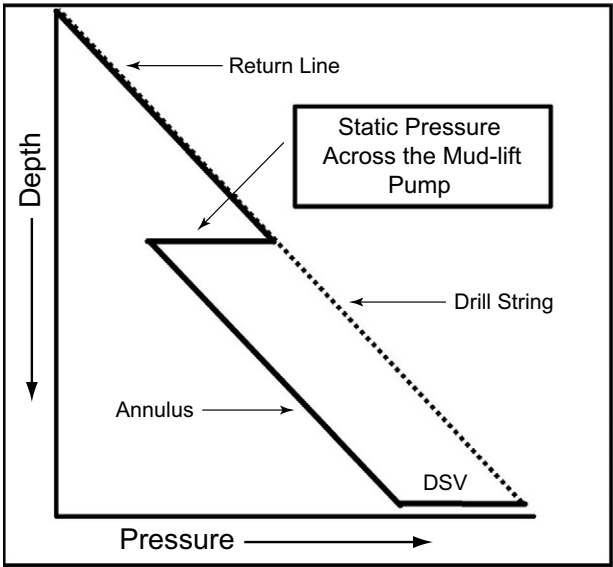


Figure 8.21 Static pressure profile of a dual-gradient well with a DSV installed.

Two aspects of DGD that make well control safer compared to conventional drilling are the widening of the pore/fracture gradient window and the riser margin. This riser margin means drilling can be conducted with larger trip and kick margins, thereby increasing well-control safety factors.

8.6.1 Recording Prekick Information

DGD well control starts with prekick measurements. This information must be measured and recorded as with conventional well control:

- First is the kill-rate pressure (KRP). This is the circulating pressure at a predetermined kill rate. The KRP is no different than in a conventional system.
- When in an active U-tube (no DSV), the kill rate must be at least equal to the U-tube rate. This is to ensure that the drill string is full of mud and a positive pressure is measured on the standpipe.
- In addition to the KRP, the inlet and outlet pressures on the subsea pump should be recorded at the kill rate.
- Annular friction needs to be either calculated or measured with down-hole pressure tools.
- Finally, with a drill string arrestor valve, the opening pressure must be measured. This is done with the same regularity as measuring KRP in conventional drilling. Simply measure the pressure required to open the valve. This is similar to cracking open a drill-pipe float to measure shut-in drill-pipe pressure in conventional operations.

8.6.2 Kick Detection

With the controls built into the DGD systems, many of the standard kick detection tools are enhanced. The basic kick indicators are:

- Pit gain.
- Increase in return rate.
- Drilling break.
- Decrease in standpipe pressure.

- Increase in surface pump speed.
- Increase in torque, drag, and fill.

All these kick indicators are applicable to DGD; however, some are enhanced. For example, the seafloor pump is used as a positive-displacement meter and is much more accurate than a “Flo-Show.” When a kick occurs, the seafloor pump speeds up to maintain a constant inlet pressure. Pressure gauges are located on the inlet and outlet of the seafloor pump. When the seafloor pump speeds up, the frictional pressure in the return line increases and can be detected by the seafloor pump outlet pressure gauge. If the seafloor pump is set to operate at a constant rate, the inlet pressure will increase when a kick occurs.

The relatively small volume in the return line compared to the marine riser allows for decreased bottoms-up time. Cuttings and gas units come up quicker and pore pressure indicators are detected earlier.

These are kick indicators; however, to verify that a kick actually occurred, the crew always checks to see if the well flows with the pumps off. Assuming that a DSV is in place, once the drill string is positioned with a tool joint above the rotary, the pumps are shut off, the DSV closes, and flow from the drill string stops. Figure 8.22 shows a negative flow check (no flow, meaning no kick). The rig pump rate, seafloor pump rate, and influx rate are all zero on shut-down of the pumps. This shows that a kick has not occurred, even though some of the kick indicators may have been present.

Figure 8.23 shows what a kick looks like during a flow check. Note that the rig pump rate goes to zero, while the seafloor pump rate increases right along with the influx rate. This is due to the seafloor pump set to operate at a constant inlet pressure near seawater hydrostatic. To maintain this inlet pressure, the seafloor pump must continue to run while the well flows. This is a very good, and sensitive, kick indicator. This can be enhanced further with additional technology developed for MPD such as the micro-flux system, which can detect very small flow rates.

Figures 8.22 and 8.23 refer to flow check with a DSV. Figure 8.23 is representative of a kick. Once a kick is verified, full well shut-in follows, as in conventional drilling techniques. If there is no U-tube

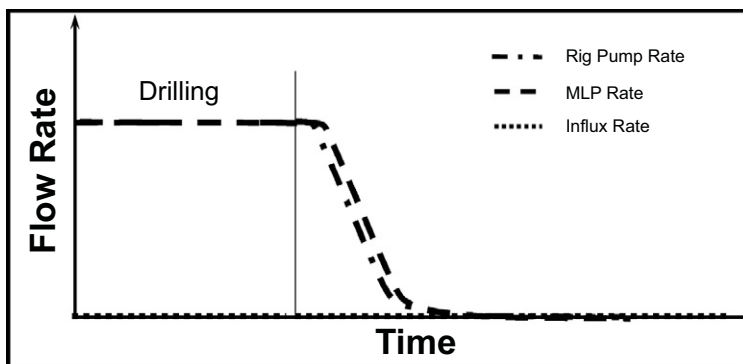


Figure 8.22 A negative flow check (no kick)—all flows go to zero.

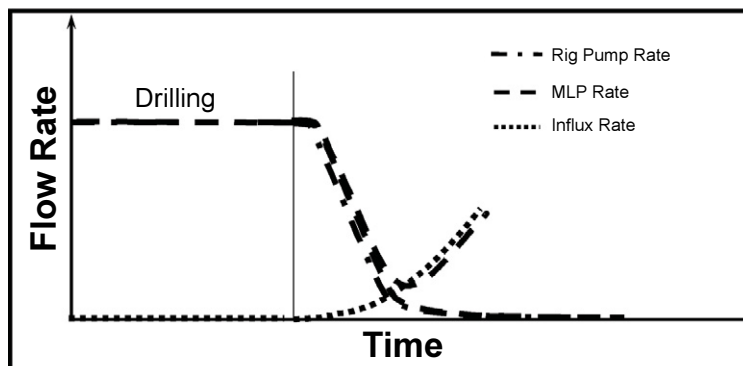


Figure 8.23 A positive flow check. Rig pumps shut down and seafloor pumps increase in rate in response to the increase in influx rate.

arrestor, the seafloor pump continues to pump as the U-tube takes place. How does the crew distinguish between a normal U-tube and a kick? Again, this requires trend analysis. If the seafloor pump does not slow down as a straight U-tube would but continues to run, a kick can be verified.

8.6.3 Dynamic Shut-in of the DGD System

The dynamic shut-in was developed to stop an influx without completely shutting in the well. This method is applicable with and

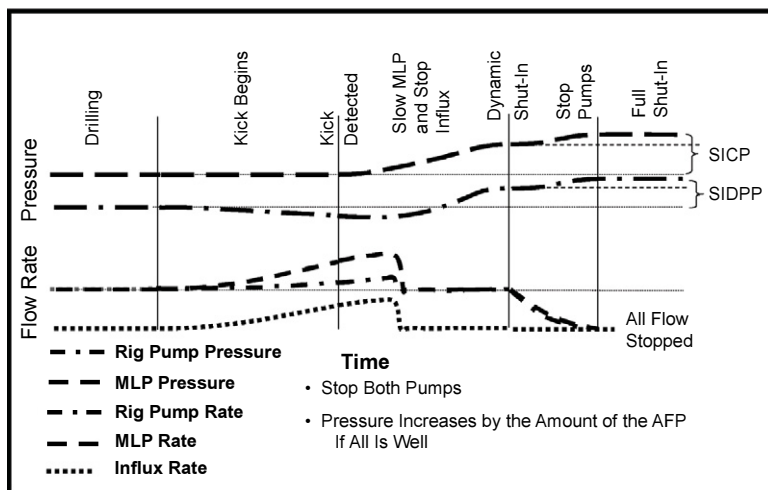


Figure 8.24 Flow rates and pressures during kick detection, dynamic shut-in, and full shut-in of a DGD well.

without a DSV and is recommended if no U-tube arrestor is in use. Figure 8.24 plots the rig pump rate and pressure, seafloor pump rate and pressure, and the influx rate prior to a kick, during detection, during dynamic shut-in, and after full shut-in. While drilling, all rates and pressures are constant.

The seafloor pump is set to operate on a constant inlet pressure near seawater hydrostatic. As the kick begins, the influx rate begins to increase. The seafloor pump speeds up to maintain a constant inlet pressure. The rig pump rate may increase slightly, and the standpipe pressure decreases. Once the kick is detected, the seafloor pump is set to operate at a constant rate equal to the prekick rate, and the rig pump rate is adjusted to the prekick rate. This is what is referred to as the *dynamic shut-in*.

With both pumps running at prekick rates, the inlet pressure on the seafloor pump begins to increase as the influx continues and the standpipe pressure also increases. The seafloor pump inlet pressure increases until the sum of the inlet pressure, annular hydrostatic pressure, and annular frictional pressure (this is the bottom-hole pressure) equals the formation pressure. At this point, the influx stops.

Since the drill string is full of mud, the increase in stabilized postkick standpipe pressure over the prekick standpipe pressure is referred to as the *dynamic shut-in drill-pipe pressure*. Now the crew is ready for a full shut-in.

On full shut-in, the rig pump and the seafloor pump are shut down to zero flow. The standpipe pressure and the seafloor inlet pressure increase over the dynamic shut-in pressures by an amount equal to the annular friction pressure. To verify this, measure the shut-in drill-pipe pressure; the standpipe pressure can be bled to zero. This can be done safely, since the DSV acts like a typical drill-pipe float and holds a pressure differential from below the valve as well as supporting the hydrostatic head of the mud in the drill string. To measure the static shut-in drill-pipe pressure, the crew slowly applies pressure to the inside of the drill pipe until the DSV opens. The shut-in drill-pipe pressure is then equal to the postkick opening pressure minus the pre-kick opening pressure previously measured. This should be equal to the dynamic shut-in pressure plus the annular frictional pressure.

8.6.4 Kick Circulation

To circulate the kick from the well, it is recommended to use the driller's method. Circulate at the kill rate and keep the drill-pipe pressure constant at shut-in drill-pipe pressure plus kill-rate pressure. This is done by adjusting the seafloor pump rate, as the seafloor pump acts like a choke.

Once gas enters the return line, it is possible for the seafloor pump outlet pressure to become lower than the inlet pressure. It is important that returns at the surface be taken through the choke manifold and a fully opened choke. If the outlet pressure begins to drop and approaches the value of the inlet pressure, adjust the surface choke to maintain the outlet pressure at some value greater than the inlet pressure.

The pressure reversal can occur when gas enters the return line and becomes tall due to the ratio of the annular area compared to the return line area. This is similar to what occurs when gas enters the choke line in conventional floating drilling operations. The gas begins to expand rapidly when it nears the surface in the return line, and this further decreases the seafloor pump outlet pressure.

Placing the pumps at the seafloor provides some additional advantages over conventional riser drilling. The choke line friction pressure, which can be the cause of lost circulation during a kill operation, is never imposed upstream of the seafloor pump. In addition, since DGD is mostly applicable to ultradeep water, gas expands very little from the bottom of the hole to the seafloor, resulting in little change in the inlet pressure during a kill operation.

Once all the gas is removed from the well bore, the well is completely shut in, and kill mud is mixed and circulated from the well bore following a pressure-decline schedule. On the second circulation, the seafloor pump is set to operate at constant inlet pressure equal to the shut-in pressure after the kick removal step. Maintain this constant inlet pressure while bringing up the rig pumps to the kill rate and until the kill mud is circulated to the bit. At this point, the circulating drill-pipe pressure should have decreased to final circulating pressure. Maintain this final circulating pressure until the kill mud has filled the entire well bore. When the entire well bore is full of kill mud, shut in the well and perform a flow check. If there is no flow, the well is dead.

Since the mud density is calculated with reference to the seafloor instead of the rig floor, the calculation for kill mud density is slightly different than conventional drilling and is calculated as

$$\text{KWM} = [\text{SIDPP} \div 0.052 \div (\text{TVD} - \text{WD})] + \text{OMW} \quad (8.1)$$

where

KWM = kill mud density

SIDPP = shut-in drill-pipe pressure

TVD = total vertical depth of the well

WD = water depth

OMW = original mud density

0.052 = units constant (English system)

8.7 Additional Comments

Section 8.6 presents a fundamental description of dual-gradient drilling to provide the reader with a basic understanding of the concept.

As in all drilling technologies discussed in this book, there is much more to the actual implementation of the technology than can be covered in the space allowed.

Other dual-gradient drilling systems have been studied that utilized seafloor pumps. These include Baker Hughes Deep Vision (Sjoberg, 2000) and a project conducted by Shell (Gonzalez, 2000). These two projects were conducted at the same time as the SMD JIP. The major differences were with the types of pumps and cuttings processing systems used.

In addition to seafloor pumps, dual gradients can be accomplished by annular injection, one of which is accomplished by injecting base fluid in the riser at a predetermined volumetric rate to achieve the desired density in the riser (Okafor, 2007). Fluid can be injected through the boost line. When this lower-density fluid is circulated to the surface, the base fluid is separated from the mud stream with centrifuges and both mud and base fluid are recycled.

The second annular injection method was studied by Maurer Engineering (Maurer, 2000; Vera, 2002). This project was based on the injection of hollow glass spheres at the base of the riser. Again, the injection volume is calculated to provide the desired riser density. Separation of the spheres at the surface was planned so that the mud and the spheres could be recycled.

The third annular injection method studied was gas injection. Louisiana State University performed this study, and it is very similar to gas lift in producing wells. The air is to be injected at the base of the riser, and the mud/gas separation equipment are used to separate the air from the mud stream when circulated to the surface. The correct injection volume is calculated to achieve the desired mixture density in the riser.

8.8 Examples

Example 8.1 DGD Equivalent Mud Density

Water depth = 6000 ft.

Total vertical depth = 21,000 ft (15,000 ft below the mud line).

Seawater density = 8.6 ppG.

Desired bottom-hole pressure = 13,650 psi.

Desired seafloor annulus pressure = 2683 psi (seawater hydrostatic pressure).

Calculate the mud density for both conventional riser drilling and dual-gradient drilling.

Solution to Example 8.1

For conventional riser drilling, the desired bottom-hole pressure is simply divided by the water depth and conversion factors (in field units this is 0.052):

$$\rho_{\text{MDGD}} = \frac{13,650}{0.052 \times 21,000} = 12.5 \text{ ppG}$$

To calculate the dual-gradient mud density to provide the same bottom-hole pressure, the engineer assumes that the seafloor pump maintains the annulus pressure at the seafloor equal to the seawater pressure of 2683 psi. The remaining 10,967 psi (13,650 – 2683) must come from the mud in the annulus. The equivalent DGD mud density is then calculated by

$$\rho_{\text{MDGD}} = \frac{p_{\text{BHP}} - p_{\text{SW}}}{0.052(D_{\text{TVD}} - D_{\text{SW}})} \quad (8.2)$$

where

ρ_{MDGD} = equivalent DGD mud density

p_{BHP} = bottom-hole pressure

p_{SW} = seawater pressure at the seafloor

D_{TVD} = total vertical depth of the well

D_{WD} = water depth

Putting numbers into the equation, we have

$$\rho_{\text{MDGD}} = \frac{13,650 - 2683}{0.052(21,000 - 6000)} = 14.06 \text{ ppG} \approx 14.1 \text{ ppG}$$

Example 8.2 U-Tube Distance and Volume

Assuming the information in Example 8.1, calculate the distance the mud will fall in the drill pipe and the volume of the U-tube at equilibrium.

Solution to Example 8.2

The U-tube distance is calculated by calculating the height of the mud column inside the drill string that results in an equal hydrostatic pressure with the seawater hydrostatic pressure at the seafloor.

The seawater hydrostatic pressure is 2683 psi. Divide this by 0.052 and the mud density of 14.1 ppg results in a mud height of 3660 ft of mud. This leaves 2340 ft of air (6000 – 3660) in the drill string.

The U-tube volume is simply the internal capacity of this 2340 ft of drill pipe.

Example 8.3 DSV Set Point

Calculate the “set point” pressure for a DSV, assuming 14.1-ppg mud and a safety factor for the DSV of 1.0 ppg.

Solution to Example 8.3

Calculate the difference in hydrostatic pressure between the set point of 15.1 ppg (14.1 + 1.0) and the seawater at the seafloor:

$$\text{DSV set point} = (15.1 - 8.6) \times 0.052 \times 6000 = 2028 \text{ psi}$$

The DSV would be set to open with a positive opening pressure of 2028 psi. This would support the hydrostatic pressure of the mud in the drill string in excess of the hydrostatic pressure of the seawater, up to 15.1-ppg mud.

How much surface drill-pipe pressure would be required to open the DSV? Subtract the current mud weight (14.1) from the set point (15.1) and multiply by 0.052 and water depth:

$$(15.1 - 14.1) \times 0.052 \times 6000 = 245 \text{ psi}$$

As the mud density increases, the surface pressure to open the DSV decreases.

Questions

1. List the major problems associated with ultradeepwater drilling.
2. List general advantages of dual-gradient drilling over conventional riser drilling.
3. What are some advantages of applying DGD technology for the top-hole portion of the well?
4. Discuss the differences between the riserless mud return system and the controlled mud pressure system.
5. Given a prekick circulation pressure of 2000 psi, postkick circulation pressure (dynamic shut-in employed) of 2300 psi, and annular friction of 150 psi, what shut-in drill-pipe pressure should be used to calculate kill mud?
6. For the previous question, assume that TVD is 15,000 ft, water depth is 7500 ft, and the original mud density is 12.6 ppg. Calculate kill mud density.
7. For a water depth of 8000 ft, seawater density of 8.6 ppg, and mud density of 13.3 ppg, how far will the mud U-tube on complete shut-in? Assume no DSV.
8. For a well with TVD of 18,000 ft, water depth of 8000 ft, seawater density of 8.6 ppg, and mud weight for conventional riser drilling of 14.5 ppg, what mud density for DGD would be required to provide the same bottom-hole pressure assuming that the inlet pressure on the seafloor pump is maintained at seawater hydrostatic pressure?

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Answers

1. The major problems associated with ultra-deepwater drilling include:
 - a. Greater length of riser and resultant deck loads and deck space limitations.
 - b. Large volumes of mud just to fill the riser.
 - c. Large weight of the riser and riser mud must be supported by the tensioners.
 - d. Geologic objectives tend to be deeper below mud line as water depth increases.
 - e. Deeper targets require additional casing strings.
 - f. Deeper water narrows the effective window between pore pressure gradient and fracture pressure gradient.
2. The general advantages of dual-gradient drilling over conventional riser drilling include:
 - a. DGD can minimize or eliminate most of the problems associated with ultra-deepwater drilling.
 - b. Smaller drilling vessels can operate in deeper water.
 - c. TD can be reached with a larger casing size, and higher production rates can be expected from larger production tubing.
3. Some advantages of applying DGD technology for the top-hole portion of the well include:
 - a. Shallow gas, shallow water flows, and other shallow BML problems can be controlled with DGD installed prior to surface casing.

- b. The surface casing can be set deeper.
 - c. An engineered mud, or complex mud, can be used in the top part of the well since it is not dumped on the seafloor, resulting in a better gauge hole and increased probability of a successful cement job.
4. The difference between a riserless (RMR) and controlled-pressure mud system is
 - a. The RMR system does not utilize a “typical” marine riser. The drill string above the seafloor is exposed to the open sea.
 - b. The RMR system has the return pump located at the seafloor, whereas the controlled-pressure system can place the return pump at any location on the marine riser between the seafloor and the surface. The controlled-pressure system allows the riser mud level to be adjusted to control the bottom-hole pressure.
5. The RMR system has the return pump located at the seafloor, whereas the controlled-pressure system can place the return pump at any location on the marine riser between the seafloor and the surface. The controlled-pressure system allows the riser mud level to be adjusted to control the bottom-hole pressure.
6. $(2300 - 2000) + 150 = 450$ psi.

$$\text{KWM} = [450 \div 0.052 \div (15,000 - 7500)] + 12.6$$

$$= 13.75 \approx 13.8 \text{ ppg.}$$
7.
 - a. Seawater HSP = $0.052 \times 8.6 \times 8000 = 3578$ psi.
 - b. $3578 / 0.052 / 13.3 = 5174$ ft of mud in the drill string after the U-tube effect.
 - c. $8000 - 5174 = 2826$ ft. The mud falls 2826 ft.
8.
 - a. BHP = $0.052 \times 14.5 \times 28,000 = 21,112$ psi.
 - b. Seawater pressure = $0.052 \times 8.6 \times 8000 = 3576$ psi.
 - c.
$$\rho_{\text{MDGD}} = \frac{21,112 - 3576}{0.052(28,000 - 8000)} = 16.86 \text{ ppg} \approx 16.9 \text{ ppg}$$

CHAPTER NINE

Equipment Common to MPD Operations

Bill Rehm, Drilling Consultant, and
Jim Hughes, SunRock Energy

About This Chapter

Within the chapters defining the various MPD techniques are descriptions or notations of special equipment for that particular operation. This chapter details the special equipment common to some or all MPD operations. The main interest in this chapter is in the operational effect of the equipment, methods of operation, and equipment details.

Not included is the standard rig equipment, which includes the BOP stack, surface drill-pipe valves, and the special reporting systems that are part of modern rig instrumentation. This chapter contains discussions of equipment, including:

- Rotating control devices.
- Drilling chokes.
- Drill-pipe nonreturn valves, also known as *float valves* or *check valves*.
- Annular isolation valve or down-hole isolation valve.
- ECD down-hole pump.

- Coriolis meter (as a flowmeter).
- Disc pump (as a subsea pump).

9.1 Rotating Control Devices and Rotating Annular Preventers

The rotating control device is common to all MPD techniques because of the requirement that the annulus be packed off at the surface while drilling, making connections, and tripping. While an annular preventer or a pipe ram can do this as a temporary measure, the industry has come to depend on a rotating annular preventer or rotating control device to limit rotational wear while drilling. There are now special versions of the RCD for use with air drilling, geothermal drilling, riser diverters, and stripping casing, as well as sealing around drill pipe.

The rotating control device has a long history as a commercial rental tool, going back to at least the 1930s. The rotating head shown in Shaffer's 1936 catalog is not unlike modern rotating control devices. The primary difference is, in today's MPD operations, the RCD is designed to hold pressure instead of functioning primarily as a diverter for air and gaseated mud operations.

Modern rotating control devices and rotating annular preventers typically operate at pressures up to 5000-psi static and 2500-psi rotating. When rotating, the equipment is normally derated 50% from the static specification to reduce the heat generated in the bearing packs from high-speed rotation under the maximum load. Almost all the high-pressure rotating systems use circulating oil systems to lubricate the bearing and transfer the heat generated by pressured rotation (Figure 9.1).

Two basic systems are in use, the passive rotating control device and the active rotating annular preventer. Although a number of vendors provide low-pressure rotating devices for air and gas drilling, this discussion centers on the tools of the limited number of manufacturers who provide more than 90% of the rotating devices used for MPD operations.

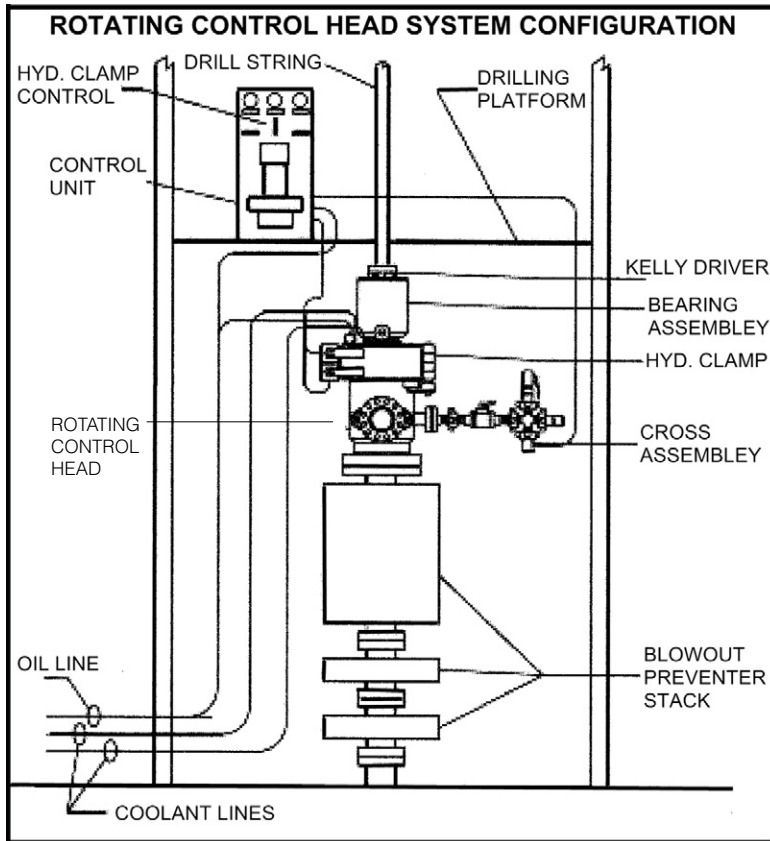


Figure 9.1 Rotating control device system configuration. (Courtesy of Weatherford International Ltd.)

9.1.1 Rotating Control Devices (Passive Systems)

The RCD (Figure 9.2) is a rotating packer that uses an annular seal element or “stripper rubber,” which is $\frac{1}{2}$ -in. to $\frac{3}{8}$ -in. (12.7–22.2 mm) diameter undersize to the drill pipe and is force fit onto the pipe. This forms a seal in zero-pressure conditions. The element is exposed to the well-bore pressure and further sealing is done by the force of annular pressure (well pressure actuation). The buildup of annular pressure against the element exerts a direct sealing pressure

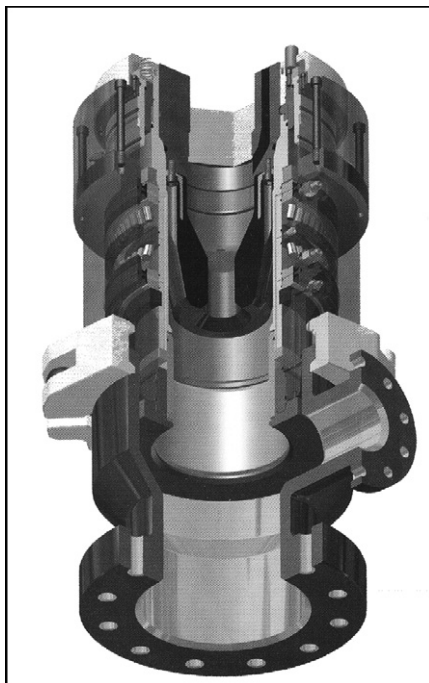


Figure 9.2 Rotating control device. (Courtesy of Smith Services.)

on a per-unit-area basis against the stripper rubber. This is described as a passive activation system.

The annular seal element is forced onto a joint of drill pipe using a special pointed sub to ease the force fit. The annular seal or stripper element is bolted to a carrier set into a bowl containing the bearing system and locked into place by a quick-connect collar. The annular seal element rotates with the pipe and is locked and sealed into the bearing assembly. The bearing pack is lubricated and cooled by a circulating hydraulic oil system.

No action needs be taken by the driller during drilling or stripping operations. The seal rubber responds to annulus pressure. When stripping is no longer required, the rotating seal assembly is released from the bearing pack, and the drill-pipe stand holding the assembly is set aside. When stripping in the hole, the seal element is

lubricated by keeping the bowl on top of the rotating element full of water (or oil).

The Weatherford high-pressure RCD uses dual elements (Figure 9.3). The upper element is a backup against seal leak from wear in the lower element. The lower element takes the pressure differential, does most of the sealing, and has about 60% of the wear. The dual stripper rubbers are far enough apart that, when a tool joint is passed, one rubber is always sealed against the drill pipe and prevents leakage of a gas from the well bore.

The failure mode for the passive RCD in most cases is a leak in the seal around the pipe or drill collars at low pressure. As the packers or strippers wear, they reach the point where they do not seal tight at low pressures. While a leak may show up on a pressure test, leaking normally is seen on the drill floor during a trip or a connection under pressure.

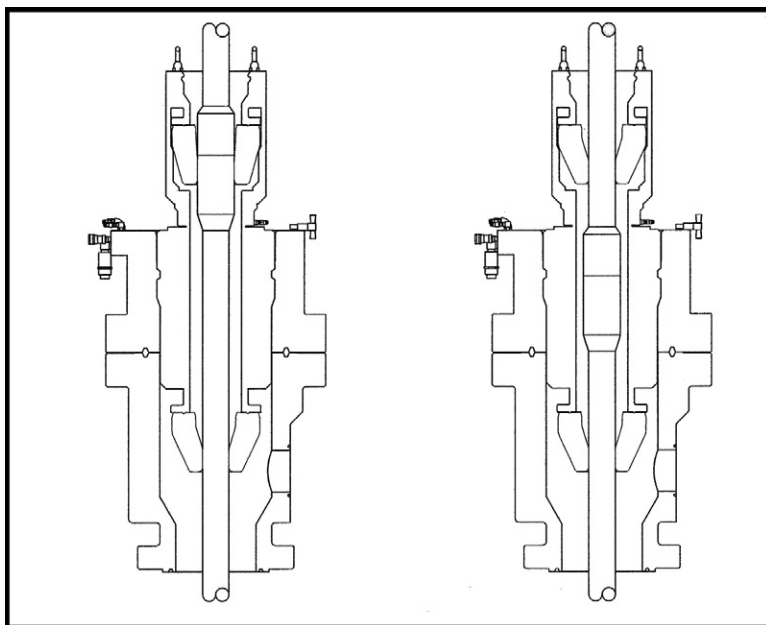


Figure 9.3 Dual stripper units in a high-pressure RCD. (Courtesy of Weatherford International Ltd.)

9.1.2 Rotating Annular Preventors (Active Systems)

The rotating annular preventer is a hydraulically actuated annular packer. The most classic example of this is the Varco Shaffer pressure-control-while-drilling (PCWD™) rotating annular preventer (Figure 9.4). While not accepted in all legal jurisdictions as an annular blowout preventer, it is basically a Shaffer spherical annular preventer mounted on a bearing pack. It is not well pressure actuated but actuated by a hydraulic ram that forces the packer element up against the spherical head, where it packs off against the pipe. Dual hydraulic systems are used. The basic system operates the closing and opening of the preventer and a second system is used to cool and lubricate the bearing pack. The PCWD is larger than the equivalent-size Shaffer spherical annular preventer and better suited to large rigs with adequate clearance between the rotary table and the wellhead.

The PCWD packer is an annular preventer, opened when pressurized drilling or tripping is not required. Packer change-out is

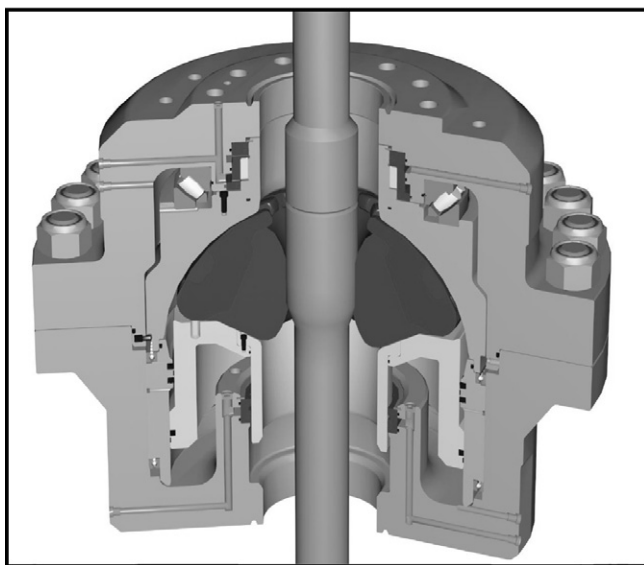


Figure 9.4 Varco Shaffer PCWD™. (Courtesy of National Oil Well Varco Shaffer.)

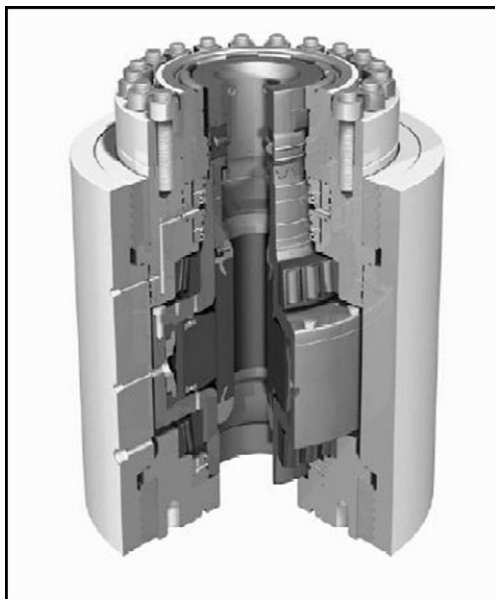


Figure 9.5 Section of the RBOP™. (Courtesy of Weatherford International Ltd.)

infrequent and similar to changing the conventional spherical annular preventer. The system is highly automated, and no action is required from the driller except to close or open the packer. Packer pressure is controlled automatically or can be manually controlled from the control panel.

Other active rotating systems include the original RBOP™ (rotating blowout preventer), which was developed for use in the Austin Chalk fields in the 1990s. The RBOP uses a pressurized diaphragm to squeeze a packer element against the pipe. It is smaller than the PCWD but significantly larger than the equivalent passive systems (Figure 9.5).

9.1.3 Comments on the Use of Active or Passive Systems

The passive rotating control device is the most common system in use. Excluding the very large number of low-pressure units used on

air drilling rigs, high-pressure RCDs make up more than 90% of the rotating control devices in MPD operations. The active hydraulic system rotating packer or rotating BOP is a newer idea, more complex, and generally a larger piece of equipment that requires more free height above the BOP stack to install.

All the high-pressure systems have rig floor gauges, alarms, and controls. They all have a surface hydraulic unit to circulate oil for cooling, and in the case of active systems, a separate system for closure. All the hydraulic units draw electric power from the rig. The hydraulic cooling and operating systems are set remote from the drill floor, with hydraulic lines run under the floor to the unit. In almost all cases, active intervention when well-bore pressures increase or decrease is not necessary.

Holdup or Snubbing Force

Common to all RCD and rotating annular preventer systems (and all BOPs) is that they have a snubbing force, “holdup weight.” The grip of the packer or stripper around the drill pipe, reduces the reading of string weight and so the bottom-hole bit weight is higher than recorded on the surface weight indicators. The reduction on the surface weight indicator can be in the range of 2–5 tons. While this is not normally a problem, it can cause difficulty when very light bit or milling weights are required.

Packer Life

Problems that lead to a short packer or element life include:

1. Improper-size stripper rubber for the drill pipe in use (passive units).
2. Rig is not centered over the hole.
3. Bent Kelly.
4. Sharp edges on the Kelly.
5. Rough, hard banding.
6. Inside diameter (ID) grooves in high-strength pipe.
7. Tong marks on the tool joints or pipe.

8. Stripping at high speed.
9. Improper compound for the packer for oil mud or extreme temperatures.
10. Storing packer units in the sun or in the electrical generator room.

9.1.4 Rotating Control Devices on Risers

Rotating Diverter Device

The rotating element on top of the diverter (Figure 9.6) was developed as a way to deenergize pressured sand stringers in the top part of the hole. It allows the pipe to be moved in the diverter during a gas flow and to drill through the stringers instead of leaving the drill pipe in a static position. This operation requires that the low-pressure riser slip joint be locked closed and the seals pressurized. This is not properly an MPD procedure, but it leads logically to the next discussion on the riser cap.

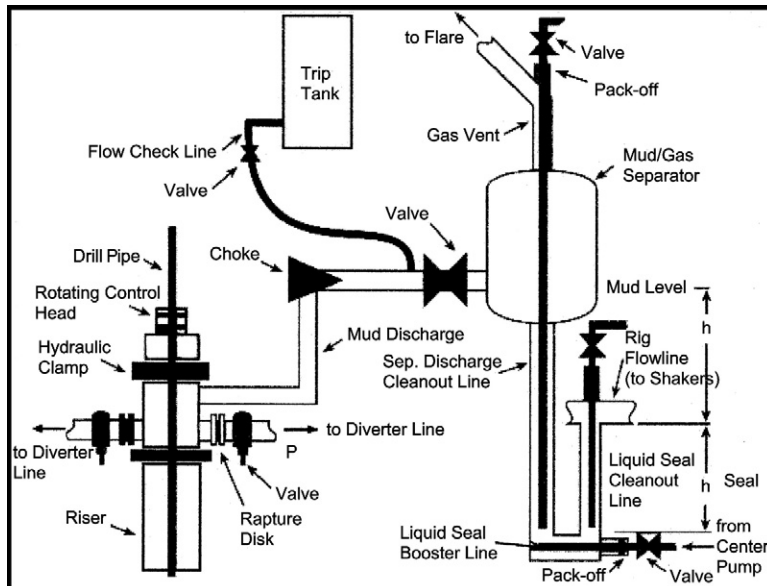


Figure 9.6 Rotating element on a riser. (Courtesy of Weatherford International Ltd.)

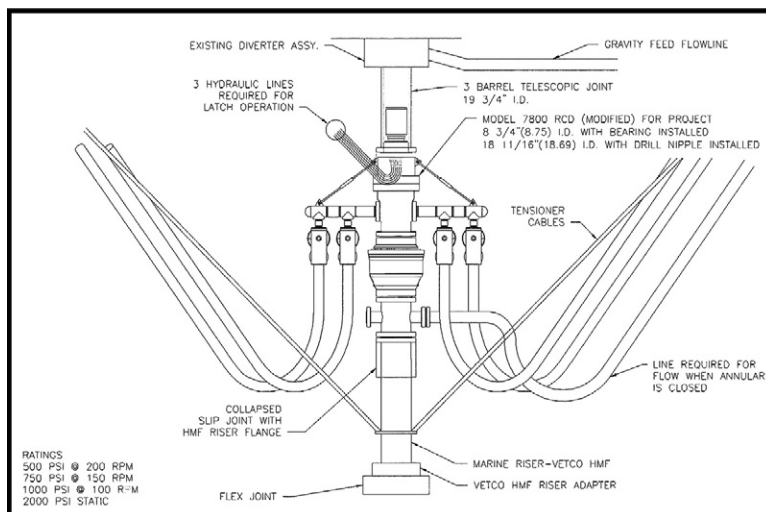


Figure 9.7 RiserCap™ in RCD docking station configuration. (Courtesy of Weatherford International Ltd.)

Riser Cap

The riser cap is a modification of the RCD that can be used for a pressurized mud cap as well as an MPD operation where low pressures are involved. It also allows drilling ahead with a control system that protects the rig and returns oil mud and other such fluids to the mud system. When the slip joint is collapsed and locked, a typical 21¼-in. lower riser has a burst of 500 psi (3 500 kPa). Modification needs to be made to flow and control lines to allow for vessel heave, as noted in Figure 9.7.

9.2 Chokes

The chokes used in MPD operations are generally separate from the well-control chokes. Since the MPD choke system is under constant use, it is considered prudent to have a separate, dedicated system for well control, even though the equipment is similar.

Choke closure elements used with MPD can be fitted into three categories: choke gates, sliding plates, and shuttles.

All the rental chokes have operating panels with drill-pipe and annular pressure gauges, choke operating controls, and a power source for choke operation. The chokes are normally H₂S rated with equipment used for MPD normally set for 10,000-psi maximum operating pressure.

Several companies manufacture remotely operated drilling chokes. The greatest numbers of remotely operated chokes used for MPD are from the two service companies whose equipment is described in the following subsections.

9.2.1 Power Choke

The Power Choke SC models use a cylinder-type choke gate that moves forward to choke against a seat (Figure 9.8). The trim is pressure balanced to allow smooth operation. When closed, the choke gate sets against the seat to form a leak-tight seal.

Choke operation is by an air-operated hydraulic pump. Normal operation is a hydraulic motor that operates a worm gear, although an electric motor is available. The hydraulic motor is rated for 1200–3000 starts and stops per hour to allow continuous precise choke operation. A manual override is on all worm gear drives.

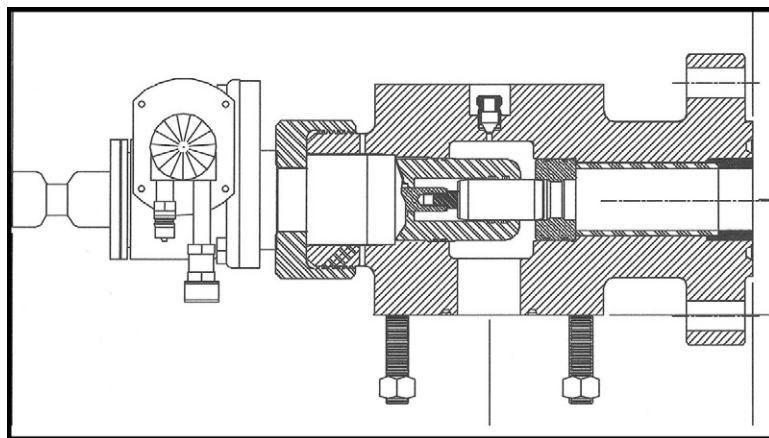


Figure 9.8 Power choke section. (Courtesy of Power Choke.)

The control panel contains the pump stroke counters, hydraulic pump, annular and drill-pipe pressure gauges, control handle, choke position indicator, and pump-speed controller, which controls the opening and closing speed. Chokes are available in 5000-, 10,000-, 15,000-, and 20,000-psi operating pressure models. Drilling chokes for MPD operations are available in 2-in. and 3-in. sizes.

Operation is with a handle for “open” and “close.” The operator controls the choke movement. Unless moved, the choke remains in a fixed position. During MPD operations, the choke maintains a fixed “orifice” unless changed by the operator. Opening and shutting during pump changes are controlled by the choke operator.

Failure is extremely rare and generally relates to the inability to seal tightly on a pressure test. The normal *operating* failure is because of damage to the air or hydraulic system. Because of the worm drive operating system, the choke operating failure mode is always in the last fixed position.

The Power Choke has been extensively used in MPD operations. A computer control system that automatically maintains the proper back pressure based on feedback to a proprietary software system is used by Secure Drilling (Chapter 4) for control during MPD operations.

9.2.2 Swaco Super Choke

The Swaco Super Choke has two 1¼-in.-thick lapped tungsten-carbide plates with half-moon openings. The front plate is fixed and the rear plate rotates against it to fully open when the openings in the plates are aligned and closed when they are out of phase. Well pressure behind the rotating plate and the lapped seal on the plates allow the choke to close and seal tightly (Figure 9.9). The half-moon openings, when in phase, have an area slightly less than 2 in.².

The choke movement is by an air-operated hydraulic pump. Normal operation is a set of hydraulic rams turning the choke plate through a rack and pinion system. Manual pump operation is available if the air supply fails. The choke can also be operated manually by lever.

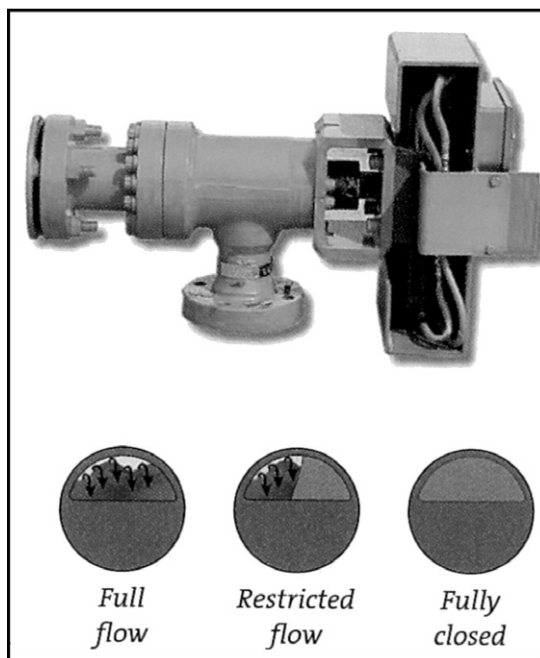


Figure 9.9 MH SWACO 10K Super Choke and choke plates. (Used with permission—MH L.L.C.)

The control panel contains the pump stroke counters, hydraulic pump, annular and drill-pipe pressure gauges, control handle, choke position indicator, and a needle valve that controls the opening and closing speed. Chokes are available in 10,000-, 15,000-, and 20,000-psi operating pressures. All chokes are rated as 2-in. chokes.

Operation is with a handle for opening and closing. The operator controls the choke movement. Unless moved, the choke remains in a fixed position. During MPD operations, the choke maintains a fixed “orifice,” unless changed by the operator. Opening and shutting during pump changes is controlled by the choke operator.

Failure is extremely rare and generally relates to the inability to seal tightly on a pressure test. The normal operating failure is because of damage to the air or hydraulic system. Because of the

rack and pinion operating system, choke operating failure mode is always in the last fixed position.

9.2.3 Swaco Auto Super Choke

The Auto Choke is suited to MPD operations because it holds the annular pressure constant. The shuttle closes bubble tight on a metal-to-Teflon seal (Figure 9.10).

The Auto Choke is a completely different choke from the Super Choke. The Auto Choke has a tungsten carbide sliding shuttle in a sleeve directly operated by hydraulic pressure. Pressure set at the console works against the operating area on the shuttle, which is balanced by the well pressure. The casing pressure transmitter is a piston shuttle providing direct pressure to the control panel sensor. The response of the choke to pressure changes is rapid.

Choke movement is directly controlled by the hydraulic balance between the well-bore pressure and the hydraulic pressure setting. Normal operation is with an air-operated hydraulic pump. Alternate operation is with a manual hydraulic pump.

The control panel contains the set-point indicator, set-point control, pump stroke counters, hydraulic pump, and annular and drill-pipe pressure gauges. This choke is available in 10,000-psi operating pressure and is rated as a 3-in. choke.

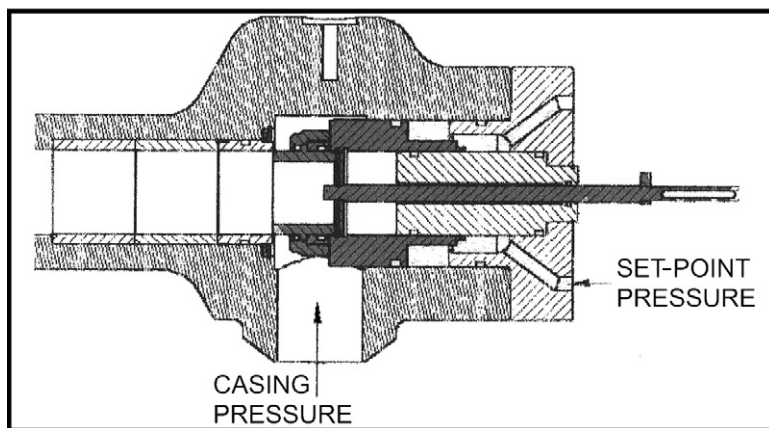


Figure 9.10 Auto Super Choke. (Used with permission—M-I L.L.C.)

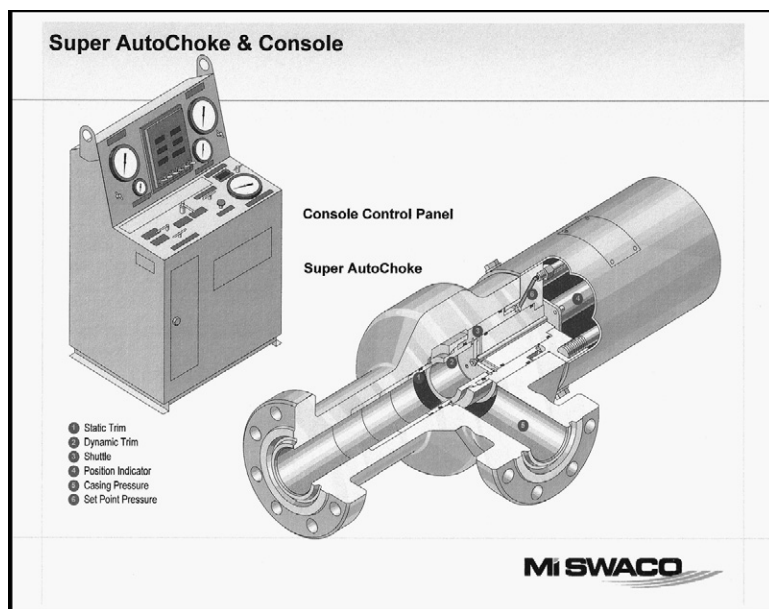


Figure 9.11 Super Auto Choke and console. (Used with permission—MH L.L.C.)

The Auto Choke normally is set in the auto mode, which maintains the casing pressure at a preset value. No further action is required by the operator as long as the preset casing pressure is not to be changed. The Auto Choke can also be operated in a manual mode with the operator controlling the casing pressure (Figure 9.11).

Failure is rare, with most problems relating to seal tightness on a pressure test. In case of low air pressure, the hydraulic pump can be operated manually. If the hydraulic control lines are cut, the choke goes to the open position.

9.3 Drill-Pipe Nonreturn Valves

The drill-pipe nonreturn valve (NRV) is essential to any MPD operation. MPD operations often require annulus back pressure. Looking at the U-tube principle so commonly discussed in well-control activities, it is evident that any positive unbalance in the annulus

forces drilling fluid back up the drill pipe. The drilling fluid may carry cuttings that plug the motor or MWD or, in the worst case, blow out the drill pipe.

The nonreturn valve, or one-way valve in the drill pipe, was originally called a *float*. That term is still in use in older literature and some of the equipment descriptions in catalogs. Within the last several years, the term *nonreturn valve*, or NRV, has replaced *float* as a primary descriptor of the drill-pipe one-way valve.

9.3.1 Basic Piston-Type Float

The primary line of defense against backflow problems has been the type-G Baker float, also called a *piston float*. The piston NRV has a simple piston driven closed by a spring that looks a bit like an engine valve stem. Drilling fluid pressure forces the valve open against the spring when circulating; and when the pump is turned off, the spring and any well-bore pressure force the valve closed. This type of NRV has proven very reliable and rugged. Failures of this valve have been rare and generally the result of no maintenance or very high-volume pumping of an abrasive fluid. The valve is housed in a special sub above the bit, and it is common and prudent for critical wells to use dual NRVs.

The primary two problems with the type-G float are that it blocks the drill pipe for wire line and the use of the float blocks back pressure or shut-in drill-pipe pressure from a well kick. As long as the NRV is located just above the bit, it limits the need to pass a wire line. The shut-in pressure problem is overcome by slowly increasing the pump pressure until it levels out, indicating that the valve is open and the pressure is the equivalent of shut-in pressure.

9.3.2 Hydrostatic Control Valve

The hydrostatic control valve (HCV) is a subsea version of the bit float valve used in dual-gradient drilling (Figure 9.12). It is used to hold up a column of drilling fluid in the drill pipe to avoid the U-tube effect when the pump is turned off. This would be the equivalent

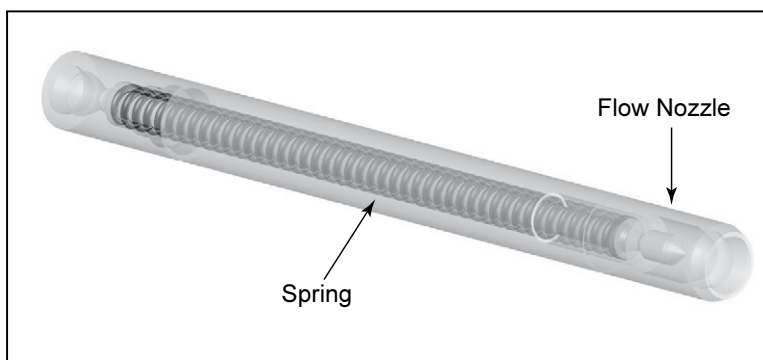


Figure 9.12 HCV valve. (Courtesy of Smith et al., 1999.)

pressure of a full column of mud in the riser minus the pressure of an equivalent column of seawater, regardless of the depth of the hole. The HCV does not restrict the use of an NRV at the bit to prevent backflow and plugging. The HCV is a longer tool than the type-G float, to accommodate the spring calibrated to hold the piston closed against the equivalent pressure of a full column of drilling fluid in the riser. See Chapter 8, Section 8.5.2, for further discussion and a different design of the tool.

9.3.3 Inside BOP (Pump-Down Check Valve)

The inside BOP is an older tool, from the generation of the piston float. The inside BOP is designed as a pump-down tool seated in a sub above the bottom-hole assembly and acting as a check valve against upward flow. The original use of the inside BOP was during a period when there were objections to running an NRV at the bit because of the chance of increasing lost circulation. It is now used as a backup to the bit float.

The inside BOP requires a sub in the drill string and inside clearance to run. The sub often, or normally, is run above the collars or bottom-hole assembly. Once run, it is not retrievable and blocks the drill string above the collars (Figure 9.13).

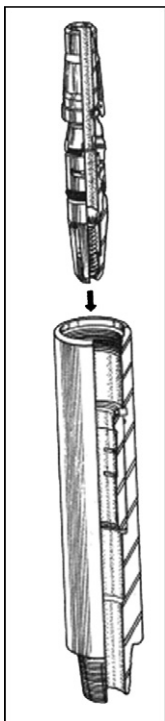


Figure 9.13 Inside BOP (NRV). (Courtesy of Rehm, 2002.)

9.3.4 Retrievable NRV or Check Valve (Weatherford)

The retrievable NRV is an improvement over the older inside BOP, since it can be pulled without making a pipe trip to the surface. There are two versions:

1. The wire-line retrievable dart valve is a reliable system that sets in a sub but does not allow access below it (Figure 9.14).
2. The retrievable check valve is a flapper-type NRV. The valve leaves an opening for balls or wire-line passage through the valve.

9.4 Down-Hole Annular Valves

9.4.1 Casing Isolation Valve

A significant problem in MPD is maintaining control of bottom-hole pressure on a trip. The basis of the MPD system is that it is

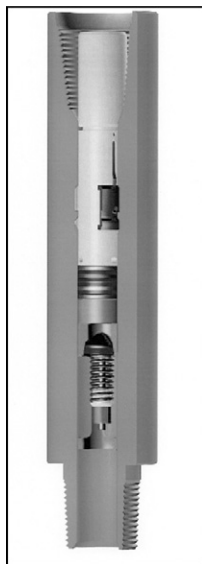


Figure 9.14 Retrievable NRV. (Courtesy of Weatherford International Ltd.)

closely balanced between flow into the well bore and lost circulation. The ECD as a result of pumping versus being static and pulling pipe versus running pipe goes through critical pressure changes. This makes it difficult to control bottom-hole pressure during trips. Trips can be managed by the use of a casing isolation valve (CIV), stripping, snubbing, or killing the well. All of these solutions pose technical or cost and NPT problems.

Advantages

The CIV offers the most positive solution to the MPD problem of trips. With a casing isolation valve, the pipe is stripped up into the casing until the bit is above the valve. The casing isolation valve is then closed, trapping any pressure below it, which allows the trip to continue in a normal mode without stripping or killing the well.

The well bore below the CIV comes to equilibrium with the reservoir pressure. So, in a high-pressure well, to limit pressure buildup below the valve caused by gas migration, the valve needs to be set as deep as practical. This also has the advantage of limiting stripping distance up to the valve level.

Constraints

The CIV requires a size larger casing to allow space for the valve element to retract and clear the bit. There are also reasonable differential pressure limits, typically in the range of 4000 psi. Extreme-bent housings ($> 3\text{--}4^\circ$) with stabilizers, used in directional drilling, may damage the face of the valve.

9.4.2 Drilling Down-Hole Deployment Valve

The drilling down-hole deployment valve (DDVTM; Weatherford) is a casing isolation valve run as an integral part of casing that is to be set above the formation of interest. The design profile of the tool allows for installation in standard casing programs: The outside diameter (OD) is such that the DDV tool can be installed inside consecutive standard casing strings, and the ID allows for full bore passage. The tool is operated from the surface by an umbilical containing two hydraulic control lines, which are run external to the casing, exiting the casing hanger through a penetrating well-head, or by using a flanged side port. With the DDV tool installed and the casing landed, the equipment on the surface is a small footprint hydraulic control unit.

The valve mechanism itself is a curved, saddle-type flapper, which lands on a matched metal seat to provide the seal. The curved flapper in the open position fits flat against the outer casing string. The tool is run into the well as part of the casing, with the flapper in the locked open position. It is protected during the run-in and drilling by a seal mandrel equipped with a debris barrier (Figure 9.15). This allows the casing to be cemented in place conventionally with the flapper fully protected. With the flapper in the open position, the well operator has full bore access for operations such as cement cleanout, drilling, running a liner, perforating, and well completion.

When making a trip out of the hole, the pipe is stripped out until the bit is just above the DDV valve. Then, the flapper on the DDV valve is closed by the application of pressure to the “close” control line. Pressure from the control line moves the seal mandrel upward, allowing the flapper to move into the closed position. This isolates the upper part of the hole from pressure below. The upper annular pressure is bled off, and the pipe tripped normally.

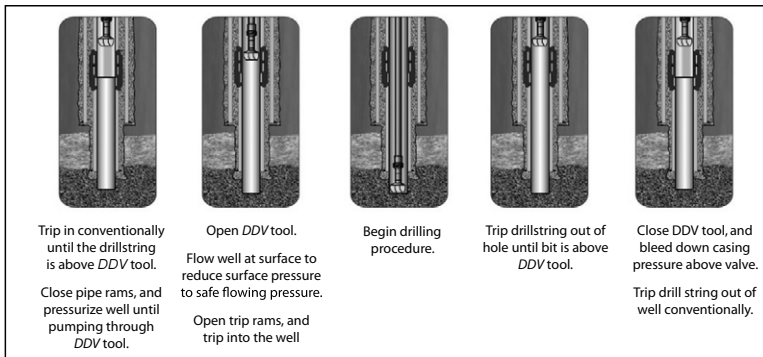


Figure 9.15 DDV trip sequence. (Courtesy of Weatherford International Ltd.)

Going back in the hole, the pipe or tubing is run in to just above the valve. The rams are closed and the upper well bore is pressured up to equal to the annulus below the DDV valve and fluid pumps through the valve. At this point, hydraulic pressure is applied to the “open” line, driving down the protective seal mandrel and opening the valve. It is important to note that the tool is not pressure equalized, but the DDV tool is a power-open, power-closed device. The pressure must be equalized before opening.

Advantages

- The well pressure is isolated below the DDV tool once it is closed. Since there is no pressure at the surface, conventional tripping is feasible.
- The well remains in an underbalanced or balanced condition while tripping.
- Tripping time is significantly less than with any other pressurized or flowing well-bore system.
- No mud density changes are required.
- Minimal footprint and surface equipment are used while drilling.
- It allows for deployment through the BOP stack of long complex assemblies.

- The DDV can be run on a tieback liner and removed at the end of drilling and completion.

Limits

- The DDV should not be used on a long-term basis (for production). It contains elastomeric seals that can deteriorate over time when exposed to well effluent.
- The hole size or previous casing needs to be a size larger.
- Pressure limits on the tool must be considered.
- The umbilical cord must be protected during cementing, which may limit pipe reciprocation.

Three Case Histories

By the end of 2007, more than 200 runs with the down-hole deployment tool had been made:

- An offshore gas field development in Indonesia was planned for a total of five wells; however, the use of MPD techniques in tandem with a DDV led to the first two wells having capacities in excess of the planned production handling facilities.
- A well in Papua, New Guinea, experienced severe fluid losses, resulting in recommendations for abandonment. The use of MPD techniques combined with a DDV resulted in regaining control of the well and drilling the productive formation in just four days and the subsequent completion of major new discovery.
- The use of a 7-in. DDV tool, set at 8718 ft in an Omani well, enabled underbalanced perforating of a 600-ft interval, using tubing-conveyed guns, and subsequent safe retrieval of the guns under pressure. A gas-lift installation was then completed in an underbalanced condition, using the facility provided by the DDV tool.

9.4.3 Quick Trip Valve

The quick trip valve (QTV™), Halliburton's version of the casing isolation valve, is run as an integral part of a standard casing string. The valve does not require a larger casing string but, in the open position,

restricts the ID of the casing string (Figure 9.16). The operation of the QTV is totally mechanical, and it can be run at any depth.

To open the valve, the upper annulus is pressured up to the same pressure as below the QTV. A slight overpressure cracks open the valve and acts on the surface like the beginning of a leak-off test. The drill bit acts as the running tool. Pushing through the flapper, it opens the valve. Carried on the gauge shoulder of the drill bit is the engaging sleeve. As the bit passes through the valve, a detent pulls the engaging sleeve off the bit and the ring locks the flapper open. The engaging ring also acts as a debris shield and seals the flapper against the wall of the casing sub.

To close the valve, the bit is pulled through the engaging sleeve, which catches on the shoulder on the bit gauge and is pulled free. As the bit clears the valve flapper, it closes and seals the lower well bore.

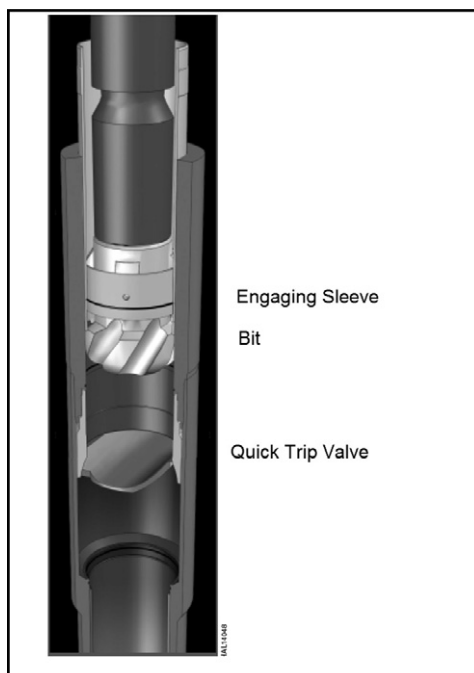


Figure 9.16 Quick trip valve.

Advantages

- The valve is totally mechanical and can be run at any depth.
- The well pressure below a closed QTV tool is isolated from the surface.
- The well remains in an underbalanced or balanced condition while tripping.
- Tripping time is significantly less than with any other pressurized or flowing well-bore system.
- No mud density changes are required.
- No surface equipment is required.
- Long assemblies can be run into the hole through the BOP stack with no danger from well pressures.
- It can be left in the hole at the end of drilling and completion.

Limits

- There is an internal restriction in the casing.
- Pressure limits on the tool must be considered.

9.5 ECD Reduction Tool

The ECD reduction tool (ECD RT™; Weatherford) is a turbine pump down-hole tool that produces a dual gradient in the annulus when the mud pump is operating. As such, it is properly both an ECD reduction tool and a dual-gradient system tool. The concepts of dual gradients and how they reduce annular and bottom-hole pressure are discussed in Chapter 8. Dual-gradient drilling in the case of this tool is accomplished by “boosting” an upper section of the annulus mud column.

9.5.1 Unique Considerations

The ECD tool works in the opposite direction from the “impressed-annulus-pressure” systems. The ECD tool reduces the pressure in the annulus instead of impressing a pressure. The result of this is that a slightly heavier mud density could be used with this tool than

with the impressed-pressure techniques. This results in being able to navigate through narrow drilling windows by widening the down-hole pressure margins.

Dual-gradient operations have an ongoing problem with the U-tube effect. When the mud pump is turned off, the system wants to U-tube to equilibrium. While utilizing the dual-gradient concept, the ECD RT tool does not cause a U-tube effect, because the static mud density is similar in both the drill pipe and annulus.

Several early references indicated a 450-psi (3100 kPa) reduction in annular pressure at 600-gpm (2300 Lpm) flow rate.

The ECD RT was designed and developed jointly by BP and Weatherford to provide a low-cost, easy to install and use, tool for ECD reduction.

9.5.2 Advantages

- It requires no drill rig modification or surface footprint. It can be added to the drill string on a short trip.
- No on-site operator is required.
- It can reduce spikes in equivalent mud-weight values associated with making connections. The result is a more constant well-bore pressure profile, whether drilling ahead (pumps on/circulating) or making a connection (pump off/not circulating).
- In extended-reach wells, it could reduce the ECD problem between the toe and the heel of the well by boosting the drilling fluid in the long reach section.
- It does not affect mud-pulse MWD signals.
- The tool is open to wire-line operations.

9.5.3 Challenges

- The most significant challenge is when running or pulling the tool. The turbine pump section in the annulus limits the annular area over a short section (Figure 9.17). Pipe movement creates an increased pressure-surge proportional to the rate of pipe movement.

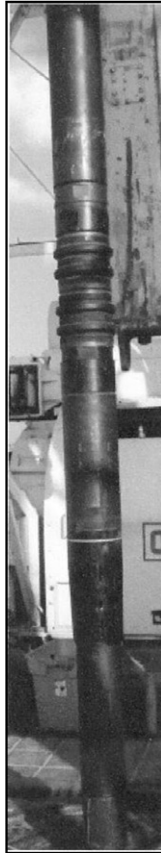


Figure 9.17 ECD tool. (Courtesy of Weatherford International Ltd.)

- The annulus restriction passes normal cuttings, but heavy gumbo could cause a problem.
- The internal drill-pipe turbine motor uses energy and so increases pump pressure.

9.5.4 Description

The ECD RT tool consists of three sections (Figure 9.18):

1. At the top is a turbine motor, which draws pressure energy from circulating fluid and converts it into mechanical power.

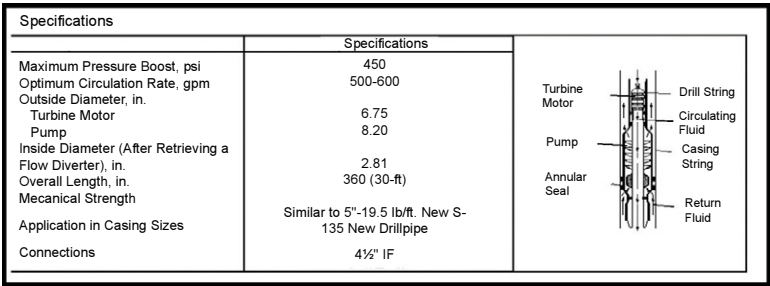


Figure 9.18 ECD tool data. (Courtesy of Weatherford International Ltd.)

Circulating fluid enters the turbine motor at the top and comes back into the drill string after driving the turbine motor.

2. In the middle is a multistage, mixed-flow pump driven by the turbine motor. It pumps return fluid up in the annulus.
3. The lower section consists of bearings and seals. The turbine motor is matched to pump duty so there is no need for a gear-box. Two seals on the outside of the pump seal it against the casing ID, which forces all the return fluid to pass through the pump.

9.6 Coriolis Flowmeter

The flowmeter is an important part of flow measurement in some MPD operations. Since the Coriolis meter is new to drilling operations, the following description is included as part of the general background for surface equipment.

The flowmeter discussed in Chapter 4 is the Emerson Micromotion Coriolis Meter. The Coriolis meter depends on a flowing mass deflecting a tube. Typically this is shown as a U-tube (Figure 9.19), and this is the configuration shown in Chapter 4. The Coriolis meter is a very accurate method of measuring drilling fluids since they contain drill cuttings that tend to interfere with other types of flowmeters. The meter measures and calculates:

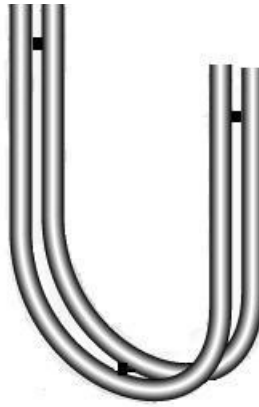


Figure 9.19 The basis of the Coriolis meter is twin parallel tubes.
(Courtesy of Yokogawa.)

- Mass flow.
- Volumetric flow.
- Density.
- Temperature.

Following is a simple general description of how the system works. For a more precise description and the mathematical concepts, see the references under Coriolis Meter.

1. Dual parallel flow tubes, U-tubes, are oscillated in opposition to each other at their natural frequency by a magnet and coil.
2. Magnet and coil assemblies are mounted on the inlet and outlet side of the parallel flow tubes with the magnets on one tube and the coils on the other.
3. The vibration of the tubes (see Figure 9.19) causes the coil output to be a sine wave that represents the motion of one tube relative to the other.
4. When there is no flow, the sine waves from the input and output coils coincide.

5. The coriolis effect from a mass flow through the inlet side of the tubes resists the vibration. The coriolis effect from the mass flow through the outlet side of the tubes adds to the vibration.
6. The phase difference between the signal from the input and output sides is used to calculate mass flow.
7. Frequency change from the natural frequency indicates density change. Increasing mass decreases frequency.
8. Volume flow is mass flow divided by density.
9. Direct temperature measurement is used to correct for temperature changes.

9.7 Disc Pump (Friction Pump)

The disc pump (Figure 9.20), referred to in RMR dual-gradient operations, Sections 8.3.3 and 8.4.3, is also variously called a *friction pump*

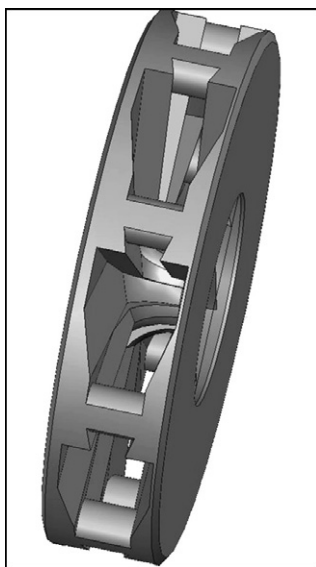


Figure 9.20 Disc pump. (Courtesy of AGR Subsea AS.)

or more generally a *subsea pump*. However, the term *subsea pump* covers a number of pumps. As noted in Section 8.5.1, other subsea pumps have been proposed for other dual-gradient operations.

The disc pump, as originally designed, has a number of parallel plates, some thousandths of an inch apart. When spinning, the friction of the fluid between the plates causes a pumping action. The close proximity of the plates limits the pumping action to low-viscosity fluids. In the 1970s and 1980s, it was found that the frictional concept was still effective when the plates were up to 20 in. (500 mm) apart. The disc pump, so configured, is more efficient than a centrifugal pump, especially with high-viscosity fluids.

Further work developed a high-head disc pump that handles fluids with entrained solids and gas. This high-head pump, further modified, is the basis for the AGR subsea pump. It pumps mud and cuttings as well as gas-cut mud. It, furthermore, holds a column of fluid at a fixed height. The AGR system is run with a frequency-controlled motor to give torque at any speed.

Questions

1. What is the most common failure mode in passive RCD systems? When is it most commonly found?
2. What is the main difference between RCD passive systems and the active systems?
3. What problems may lead to a short packer or element life in a RCD?
4. What are the benefits of annular valves (DDV or QTV)?
5. The hydraulic control valve version of the NRV is used in dual-gradient operations. What is the purpose of the hydraulic control valve?
6. In MPD operations, is it important that the choke close is sealed, or is it adequate that the choke work only as a throttling valve?

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Coriolis Meter

General information available at www.flowmeterdirectory.com/flowmeter_artc/flowmeter_artc_02020102.html, and www.yokogawa.com/fld/FLOW/rota/fld-rotamass-01en.htm.

Disc Pump

Information available at www.Discflo.com.

Answers

1. The failure mode in most cases is a leak. As the packers or strippers wear, they reach the point where they do not seal tightly on a low-pressure test.
2. In passive systems, the element is exposed to the well-bore pressure and further sealing is done by the force of annular pressure (well pressure actuation). Buildup of annular pressure against the element exerts a direct sealing pressure on a per-unit area basis against the stripper rubber. In active systems, instead of well pressure actuation, the actuation is an external hydraulic force against the packer.
3. The rig is not centered over the hole; bent Kelly; sharp edges on the Kelly; rough, hard banding; ID grooves in high-strength pipe; tong marks on the tool joints or pipe; stripping at high speed; improper compound for the packer for oil mud or extreme temperatures; storing packer units in the sun or in the electrical generator room.

4. The down-hole annular valve offers a positive solution to the problem of annular pressure on trips. Above the valve on a trip, the valve can be closed, sealing off the down-hole pressure. The trip can then continue without stripping and with no danger of a “pipe light” incident.
5. First, the U-tube principle that any positive unbalance in the annulus will force drilling fluid back up the drill pipe, and second, the drilling fluid may carry cuttings that will plug the motor or MWD, or in a worst case, blow out the drill pipe.
6. In MPD operations the choke is generally used as a shutoff valve as well as a throttling valve. During connections (and trips) the choke is closed to “trap” or control the pressure in the annulus. If a circulating pump was used to help control annular pressure, then it might be reasonable that a choke would not have to close tight. In general, choke closure is an important part of MPD operations. The other side is that a valve upstream of the choke could be used for closure on connections and trips.

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CHAPTER TEN

MPD Candidate Selection

Sagar Nauduri, Texas A&M University, and
George Medley, Signa Engineering

About This Chapter

The planning process varies among companies and organizations, and it is unlikely that one group's process would suit another organization. There are, however, common concepts and some common traps in candidate selection for a managed pressure operation. In this chapter, the authors lay out a logical approach to the planning process, with comments about common errors that occur with too narrow a vision. As noted, this is not an all-inclusive planning process but rather a commentary on the methodology.

10.1 Introduction

Managed pressure drilling is one of the latest drilling technologies increasingly used to drill wells that cannot be drilled using conventional drilling techniques because of factors like deeper target depths, reservoir depletion, and narrow pore pressure (P_p) and fracture pressure (P_f) windows.

MPD is the name for a collection of old, modified, and new technologies, referred to as *variations* or *methods* of MPD, each of which

can achieve a definite *purpose*, solve a particular *drilling problem*, or meet a specific *project constraint*. For example, MPD can be applied for purposes such as eliminating a casing string or not damaging a particular section of hole, solving problems like drilling through narrow P_p and P_f windows or lost circulation zones, and meeting the constraints of quality, time, or safety. In general, it might be said that MPD helps the operator achieve the original well design.

With growing drilling problems and increasingly complicated drilling undertakings, many projects seem to be potential applications or candidates for MPD. Although MPD fits many of these scenarios, not all of these projects require MPD. Some projects might simply need changes in the casing design, better hydraulic analysis or modifications to the mud rheology, or additional or better-rated equipment. A preliminary screening process, looking at these alternatives, can help in deciding the feasibility or redundancy of MPD for the considered project.

Hence, before deciding to use MPD for the given project, it is ideal to go through a preliminary screening or candidate selection process. This chapter describes the key aspects of MPD candidate selection and feasibility determination. The chapter is not exhaustive, and the candidate selection process is unique for each project.

10.2 Candidate Selection and Feasibility Study

The MPD candidate selection process and feasibility study are very similar screening processes that finally determine the utility of MPD for a given project. In candidate selection, the well profiles that fit the application of MPD are determined from a group of well profiles; and those that cannot be drilled using MPD or do not need MPD are discarded. Here, MPD is the focus of analysis.

In an MPD feasibility study, MPD is generally one of many options considered or evaluated for the project. The project and its objective have higher precedence than the type of process to be selected. MPD is selected or discarded at the end of study. The reservoirs, wells, or the field are the focus of analysis here.

10.3 What Is MPD Candidate Selection?

In brief, the MPD candidate selection process is a preliminary screening process that picks potential (or candidate) wells that require MPD. It ultimately decides if MPD is suitable or required to meet the project's objectives.

The MPD candidate selection process is a process that understands or establishes the purpose of the project, procures and investigates the required data by performing hydraulic analysis, identifies a suitable MPD variation, suggests all the methods to achieve it, determines the viability of each method or its alternatives, and optionally looks at the required equipment, their availability, and the procedures involved in executing the MPD.

10.4 Steps Involved in Candidate Selection

The steps involved in either candidate selection or a feasibility study can be divided into the following main categories:

- Defining, identifying, and establishing the purpose.
- Procuring information.
- Performing a hydraulic analysis.
- Selecting the method.
- Determining the viability of MPD using a preliminary economic case (optional).
- Recommending equipment (optional).
- Performing a hazard and operability analysis and hazard identification (optional).

10.4.1 Purpose of the Study

As with any study or project, it is important to establish the rationale behind the study. This helps establish the constraints or key driving factors for the screening process and thus aids in defining its objectives. Hence, this should be the first step in the screening process.

Project constraints like quality, time (schedule), money, and availability of resources, such as MPD equipment and expertise, are important aspects that can determine the direction of the study. “Qualitative” constraints may include minimal formation invasion, eliminating a casing string, or zero drilling-related problems and incidents. Drilling a well before a deadline to retain legal rights; abide within health, safety, and environment (HSE) regulations; or meet company targets and policies are a few “time” constraints. A ceiling limit on available funds or fixed budgets for the project are examples of “economic” constraints.

Availability of MPD equipment, expertise, drilling platforms or drilling rigs, and other MPD resources can become very crucial and determine the direction of the project.

10.4.2 Procurement of Information

Procurement of information is perhaps the most important aspect of the entire process. Without adequate information, the outcome of the process is brought into question. Each item of missing information introduces additional error into the analysis, because each missing item of information represents another assumption that must be made.

Essential Parameters

While more information is generally better, too much information can lead to confusion and result in a candidate selection process that is cumbersome and ineffective. However, every candidate analysis requires a minimum amount of information to yield a reasonable assessment. Essential data parameters include:

- Pressure regimes:
 - P_p and P_f .
 - Formation stability (FS) limits.
 - Desired operating or working limits (if different than P_p , P_f , and FS).
- Type of drilling problems or issues to be overcome.
- Drill-string and bottom-hole assembly details:

- Available alternative drill pipe on the rig or with the drilling contractor.
- Detailed BHA design.
- Mud design and properties: Type of mud and its rheological properties.
- Well-bore geometry:
 - Casing design details, especially details of the innermost casing.
 - Bore-hole diameters exposed to the drilling process in the interval in question.
 - Directional targets, constraints, or plans.

Pressure Regimes

The P_p , P_f , and FS data define the pressure window or operation envelope for the project. This information is required for the hydraulic analysis and to determine the utility of MPD for the project. The P_p , P_f , FS, formation leak-off, safety considerations, and requirements of regulatory agencies might sometimes leave a very tiny pressure window for operation. The safety factors considered for the examples provided at the end of the chapter are 100 psi on both P_p and P_f . Holding a 0.5-ppg (0.06 gm/cm³) safety margin is generally considered a safe rule of thumb for conventional operations. Without knowing the pressure to be managed, managing the pressure is nearly impossible.

Drilling Problems

Knowing the type of drilling problem helps in better designing the mud rheology and understanding pressure regimes. This information also helps in identifying the places to watch during the hydraulic simulations, in identifying the required variation, and in equipment selection. Properly identified drilling problems may generate a solution during the analysis that is ultimately easier and less expensive to implement than MPD.

Drill-String and BHA Details

Drill-string and BHA design determine the annular clearance available and thus the annular frictional forces. This information is an

important part of the hydraulic calculations. The BHA might cause a considerable pressure drop in narrow-hole sections and thus affect the bottom-hole pressure and the surface pressure ratings and requirements.

Drill-string and BHA descriptions also assist in evaluating pump and other injection requirements. If a drilling rig or drilling contractor is selected prior to the analysis, the equipment in inventory is easy to come by. More commonly, the MPD analysis is conducted prior to rig selection, and one outcome of the analysis may be an optimized drill-string and BHA design. Regardless of whether an input to or an outcome of the analysis, the drilling tool specification has a greater effect on the hydraulics than is often assumed.

Drilling Fluid Design and Properties

The type of drilling fluid and its rheological properties are key inputs for the hydraulic simulations. These inputs affect the yield point (YP), viscosity (μ), plastic viscosity (PV), flow behavior index (n), and consistency index (K) of the mud and in turn affect the BHP, annular pressure at any point along the well bore, and determine the requirements of additional back pressure at the surface.

When gathering details on mud properties, raw measurement data are preferred over the data commonly reported. Normally, the available data might be that found on a typical mud report, described as YP and PV. Because of the nature of the friction pressure generated when mud is circulated through the well bore, an accurate value for YP is very important.

Unfortunately, because of the nature of the field calculations of mud properties, an accurate value for YP from mud reports is often not likely. Actual Fann viscometer readings are preferred. In the case of compressible mud systems, including synthetic-based mud, Fann data covering a wide range of temperature and pressure conditions are even better for the hydraulic analysis.

Well-Bore Geometry

The design, dimension, depth, and properties of the casing exposed to the potential MPD operation are important information for the

hydraulic simulations. This information helps understanding of the geometry of the cased hole. The burst and collapse ratings could provide the maximum allowable operating pressure inside the casing, which is another important factor for the hydraulic design.

Likewise, the diameter of any open-hole sections exposed to the circulating fluid is important. The open-hole diameter data should include information on washouts or likely washouts, especially because such data are known to be a consideration while drilling.

Directional details are also important, most notably with regard to differences in true vertical depth (TVD) and measured depth (MD). A surprisingly common error in MPD analysis is the simplifying assumption that this effect is not important. However, circulating friction is highly dependent on MD, while annular back pressure and hydrostatic head are dependent on TVD alone.

Auxiliary and Optional MPD Parameters

While not essential, the parameters describing the additional elements of the potential operation help in improving the MPD program design and suggesting required changes and contingencies beforehand. Optional desirable parameters include:

- Offset well data, which help in estimating the drilling time required, predicting possible drilling problems, estimating the number of casing strings required, and predicting the potential pressure variations such as high- or low-pressure zones.
- Rig information, which includes rig type, power capacity, space, and layout. This information is useful for design and executing of an MPD project:
 - The available rig space and equipment layout determine the room for additional MPD equipment and their positions and connections with the rest of the drilling equipment. Limited space can prevent use of specific MPD equipment or downsize them, which sometimes results in less flexibility in MPD execution and operation. In few cases, a different variation or method might be required to meet the given situation.

- Rig mud pits and their capacity help determine the number of muds that can be used in the design. Small rigs might not provide the multiple mud changes required for some MPD options.
- Available power ratings, mud pumps capacities, and available auxiliary pump capacities are other aspects that affect the MPD execution procedure and, hence, the selection of the MPD methods and variations.
- Complete casing design details for the well or location, which helps in looking at the possibility of eliminating a casing string(s) using MPD and verifying the design integrity of pre-existing casing or casing designed for the section before the considered interval for MPD.

10.4.3 Hydraulic Analysis

Hydraulic analysis is done to determine the frictional pressure drops, the changes in the equivalent circulating density, and the required mud weight to drill the given interval. The results determine whether MPD can be used to stay within the pressure limits and meet the drilling objectives of the project. Computer models and software are available in the industry to perform the hydraulic calculations and analysis. Software incorporating the temperature and the mud compressibility effects give more accurate results.

The preliminary hydraulic analysis typically consumes a lot of time. Most of these simulations are based on many unknown parameters and assumptions. Initially, the operation ranges of the different parameters, like BHP, annular pressure, ECD, and surface pressure, are determined for different mud properties, back pressures, and depths. These results are compared to the available window of operation and constraints. Based on this information, the mud-supplying companies can be approached. A mud that meets the project's requirements is chosen. The properties of the selected mud are then fine-tuned to obtain the most beneficial scenario of operation.

The important parameters to observe during these simulations are

1. The ECD with and without cuttings.

2. The back-pressure requirements while drilling, making connections, and trips.
3. Hole cleaning.
4. The proximity of the annular-pressure profile to the P_p and P_f profiles during drilling, tripping, and while making connections.

10.4.4 Method Selection

Many MPD variations are available in the drilling industry. Each variation fits a specific scenario and solves the problems associated with that scenario, making selection of the appropriate MPD variation quite apparent. These variations can be achieved using one or more methods, which involve use of different operating procedures or equipment. However, selection of an MPD method ultimately depends on

- The hydraulic analysis.
- The condition and constraints of the rig, equipment, operator, and regulatory agency.
- The feasibility of the option.
- Availability of equipment.
- Availability of appropriate personnel.

For a preliminary analysis, like a candidate selection or feasibility study, it is recommended to list all the possible methods and compare their pros and cons, unless definite constraints precipitate a singular choice. Sometimes, the method selection is done at a later stage, after the decision of using MPD has been made; and this stage has greater details about MPD planning and execution.

Variations and Methods of MPD

The most commonly accepted descriptions of MPD variation include:

- Constant bottom-hole pressure variation: continuous-circulation system method or application of surface back-pressure (SBP) method.
- Pressurized mud cap.

- Dual-gradient variation: subsea mud-lift drilling (SMD) or injection of lightweight mud or glass beads.
- Low-riser return system (LRRS).
- Closed system (HSE).

Description and Application of Variations and Methods

The methods of the MPD variations use different equipment or procedures to attain the same solution. The methods provide flexibility and choice to an operator if MPD is opted. Some situations where these methods are useful are mentioned here.

The CBHP variation can be attained by two methods, using a CCS or SBP method. The SBP method helps in maintaining the same BHP under static and dynamic conditions, reducing the pressure side of the operations window by the value of annular friction at that depth. This method requires relatively higher-pressure-rated equipment. However, at places where the equipment cannot stand large imposed pressures or the riser used is not high-pressure rated, the CCS method is chosen. In the CCS method, as the drilling fluid is always under circulation, no additional back pressure is required at the surface. Hence, higher-pressure-rated equipment generally are not required for this method of CBHP. The SBP method is observed to be relatively less time consuming. The common application of CBHP is for narrow P_p and P_f windows.

Note that the well-bore pressure can be held constant at only one depth in the well bore with the SBP CBHP variation. This is because the circulating friction component of ECD is always most pronounced at the bit and has less impact near the surface. Friction varies along the well bore. The annular back pressure imposed at the surface has an effect that is exaggerated near the surface and less pronounced at greater depths. The imposed pressure is the same all along the vertical depth of the well bore. Replacing annular friction (variable along the well bore) with annular back pressure (consistent along the well bore) causes the pressure to remain constant at only one depth.

The PMC variation is used in formations having massive lost circulation (LC) problems. These formations may have huge vugs, cavi-

ties, or zones with very low pressure and high conductivity that become LC zones when hydrostatic pressure is exerted on them. A sacrificial fluid (SFL) is injected down the drill string while drilling with a heavy mud cap maintained in the annulus. The annulus remains static with either no pressure at the choke or a preset pressure maintained. Sometimes, to prevent gas migration, drilling fluid is injected down the annulus. The SFL is generally an inexpensive fluid readily available in huge quantities, like seawater in offshore locations.

The SFL pumped through the drill string and out the bit carries the cuttings into these LC zones. The reservoir pressure in the LC zone keeps the mud cap in the annulus from flowing down. The mud cap fluid is selected to balance the reservoir pressure in the LC zone or be slightly underbalanced to that reservoir pressure to maintain a small pressure at the annulus.

The dual-gradient variation of MPD works in places with narrow P_p and P_f windows and where HP zones are close to normally pressured zones or LP zones and vice versa. The gradient of the mud is changed after it crosses a certain depth. This is achieved by injecting a lighter-weight fluid like lower-density mud or gas and by injecting a lighter-weight material like low-density glass spheres into the mud circulating stream.

An alternative way of achieving a similar result is by using a submerged pump placed on the seafloor. This method is called *subsea mud-lift drilling*. The subsea pump on the mud line adds energy, effectively changing the gradient at that depth, as shown in an example at the end of the chapter. A relatively higher-density mud is used to drill the well. The rig pump pumps the mud through the bit, annulus, and up to the point the mud reaches the seafloor. The subsea pump then pumps the mud from that point to the surface. Varying the gradient in the suggested manner helps in staying within the window without the requirement of additional pressure or back pressure at the surface.

LRRS is a similar variation that works well when drilling very low-pressure reservoirs. It can be considered a type of dual-gradient drilling. The height of the mud in the annulus is lower than the Kelly bushing height. This lower height is maintained by a subsea

pump placed at a predetermined depth below the rig. The pump takes returns from the riser and pumps them back to the surface through a different flow line, adding energy to the return fluids, similar to SMD.

HSE is an MPD variation that provides a closed system to meet health, safety, and environmental regulations. A common application is to drill a zone with high amounts of H_2S concentration. The closed system reduces the risk of leaks and exposure to H_2S and makes the treatment of mud easier.

Table 10.1 is a summary of the variations, methods, and possible places of application.

10.4.5 Viability of the Option

The available mud type or weight range, budget for the operation, the quality and purpose of the well, the availability of alternative options, and economic constraints are typical parameters that determine the feasibility of MPD for the given well. Even if the candidate appears to be suited to MPD (and vice versa), often one of the other parameters mentioned here precludes application of the technique.

Table 10.1 The Variations, Methods, and Possible Places of Application

Variation	Method	Application
PMC	PMC	Narrow pressure window: Low-pressure equipment at the annulus side and high pressure OK at the drill-pipe side
	PMC	Narrow pressure window: High pressure OK at annulus and drill pipe
PMC	PMC	Zones with severe lost circulation
DGD	SMD	Low-pressure and high-pressure zones: Zone not too deep for the subsea pump
	Low-weight mud	Low-pressure and high-pressure zones: Enough rig space for two muds and separation
LRRS	LRRS	Low-pressure zones
HSE	HSE	Special needs requiring a closed system

The single most important driver in MPD is the pressure to be managed. This is affected most by the available type and density of drilling fluid. Especially in isolated regions of the world, the required fluid density may not be present or likely to be generated. Usually, this constraint comes into play with regard to highly depleted reservoirs, where a single-phase liquid system (mud, water, or oil) is simply incapable of imposing a low enough pressure to prevent lost circulation. In other instances, the problem may be that no water source having appropriate density is readily available or there are no viable means of generating the appropriate rheology to impose the required pressure on the formation while circulating.

The most obvious hindrance to the application of MPD is often the cost of MPD equipment, material, and expertise. These costs vary with time, location, availability of resources, and project requirements. A preliminary economic case gives a rough estimate of the expenses involved. However, a detailed economic case must be analyzed at a later stage of the project, as close to implementation as possible.

10.4.6 Equipment

Equipment determination, selection, and recommendation is an optional part of the feasibility study. Gathering this information is recommended, as there is a lead time for all equipment, which could become a big hurdle in MPD execution in the later stages. However, given enough lead time, all required equipment can be procured with little hassle. Specific equipment to contain or manage pressure at different levels is required for MPD, along with the conventional drilling equipment available on the rig. This MPD equipment can be classified into two parts, essential equipment and optional equipment. The essential equipment includes the rotating control device, MPD choke, and pressure monitoring software. The optional equipment includes the back-pressure pump (CBHP variation), pressure-while-drilling tool (which improves the application of pressure), CCS (depending on the application), and drill-string floats (highly recommended).

10.4.7 HAZOP and HAZID (Optional)

A proper planning and execution strategy is also an essential part of successful MPD. Proper HAZOP and HAZID plans, suitable contingency plans, equipment evaluation and pressure testing, and training of the rig crew and other staff members in MPD procedures are also essential during MPD planning and execution.

During the candidate analysis phase, the HAZID may consist of a simple list of anticipated problems to be encountered during MPD operations. The identification process helps in determining requirements and limitations of many of the other parameters mentioned earlier.

A more detailed HAZOP plan can include the preliminary required procedures to avert or mitigate the hazards identified at this stage. This contingency planning may reveal additional aspects of the operation that can bring into question the viability or applicability of

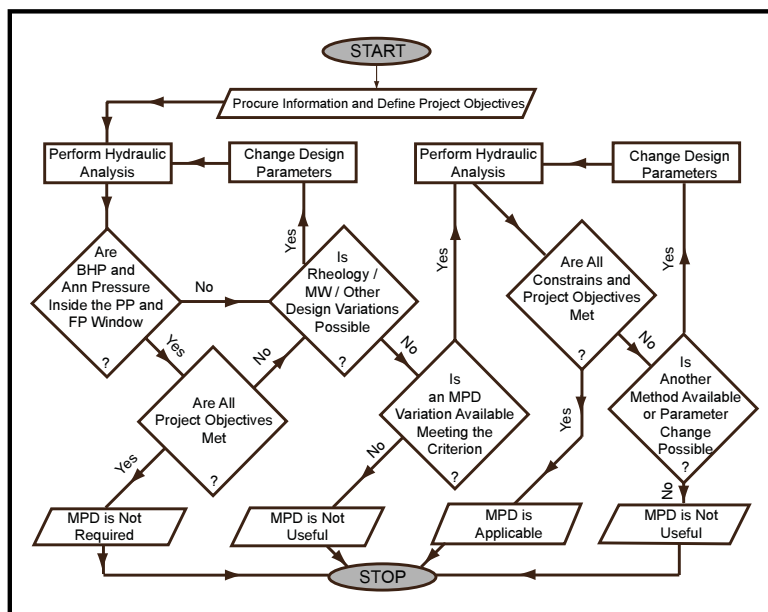


Figure 10.1 Summary of the MPD candidate selection process.

MPD for a particular well. For instance, a certain required procedure identified may result in an equipment requirement that cannot be met for the given well. If an alternative cannot be found, MPD may be eliminated as an option. On the other hand, certain contingency procedures may result in elimination of a particular equipment requirement, improving the applicability or feasibility of MPD.

Figure 10.1 is a flow diagram summarizing the candidate selection process.

10.5 Examples

All the data used in the example problems are fictitious and used purely to demonstrate the utility of a few MPD variations. All the hydraulic simulations shown in this section are courtesy of SIGNA engineering. The simulations are done using the company's ERDS software, which considers both the temperature and the mud compressibility effects while calculating the static and dynamic circulating pressures.

Both examples considered in this section are vertical holes. Hence, the TVD is the same as the MD. The safety margins considered on both P_p and P_f are 100 psi (700 kPa). It is assumed that the previous casing is run from the surface.

10.5.1 CBHP

An example for the CBHP variation is shown in Table 10.2. Dynamically, the well is inside the pressure window when circulating an 8.9-ppg mud at 500 gpm. However, under static conditions, a 350-psi back pressure is required at the surface to stay inside the window. The depth where the table is split into cased- and open-hole sections is the casing shoe depth. The solution part of the table shows both static and dynamic pressures in both the cased-hole and open-hole sections of the well.

Figures 10.2 and 10.3 show the static and dynamic pressures against depth. It can be seen that the annular pressure line moves to the right by the application of back pressure. The annular pressure

Table 10.2 Pressure Window and the Solution Using a CBHP Variation

TVD (ft)	Pressure Window (psi)			Solution (psi)		
	Pore Pressure	$P_p + SF$	$P_f - SF$	Fracture Pressure	Static Pressure	Dynamic Pressure
Closed Hole						
0	0	100	-100	0	350	0
2000	883	983	1234	1334	1275	1019
4000	1385	1485	2660	2760	2200	2036
6000	2143	2243	3815	3915	3124	3050
8000	3940	4040	4494	4594	4049	4065
Open Hole						
8000	3940	4040	4494	4594	4049	4065
8200	3956	4056	4558	4658	4141	4167
8400	3971	4071	4622	4722	4234	4268
8500	3979	4079	4654	4754	4280	4319
8700	3981	4081	4732	4832	4373	4421
8900	3983	4083	4810	4910	4465	4522
9000	3984	4084	4849	4949	4511	4573
9200	4011	4111	4919	5019	4604	4675
9400	4038	4138	4989	5089	4696	4776
9500	4051	4151	5024	5124	4743	4827
9700	4100	4200	5110	5210	4835	4929
9900	4149	4249	5196	5296	4927	5030
9992	4172	4272	5235	5335	4970	5077
10,000	4174	4274	5239	5339	4974	5081

SF = safety factor.

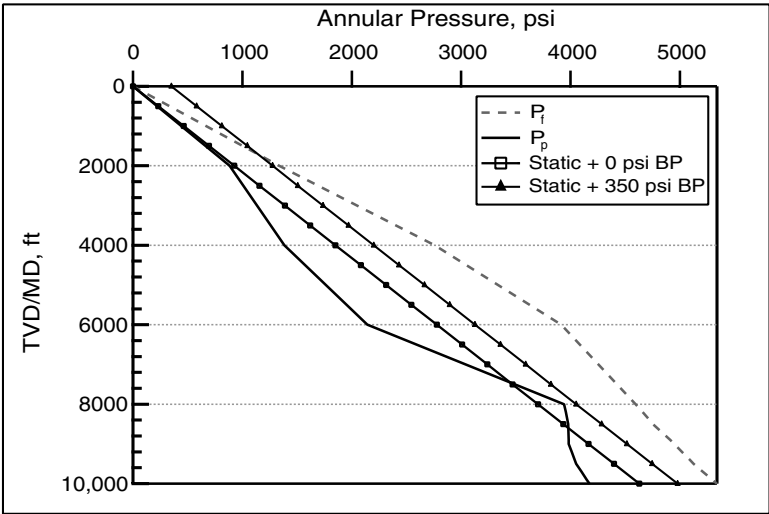


Figure 10.2 Static-pressure scenario using 8.9-ppg mud.

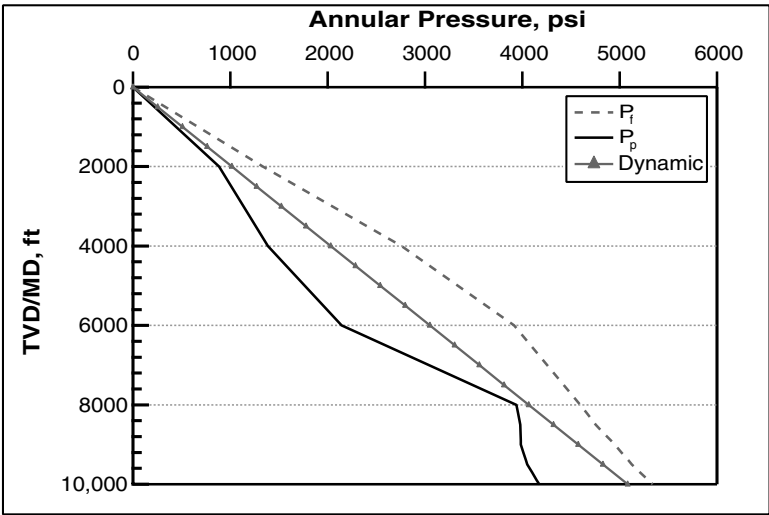


Figure 10.3 Dynamic-pressure scenario using 8.9-ppg mud.

when circulating 8.9-ppg mud at a 500-gpm rate is shown in the dynamic pressure plot (Figure 10.3).

Note that using a mud weight within the pressure window under static conditions fractures the formation when circulation starts in the open hole, ≈ 9200 -ft TVD. Hence, the conventional technique is not effective. Also, note that the annular pressure profile under dynamic conditions using MPD is still away from fracture gradient.

10.5.2 Dual-Gradient SMD

The following example demonstrates the SMD method of the dual-gradient MPD variation, which has a major utility in deepwater and ultradeepwater wells. It can be observed that both the static and dynamic pressure gradient lines are limited by the P_f at the top of the open-hole section and the P_p at the bottom, as opposed to the preceding example, in which P_p limits the window at the top and P_f limits it at the bottom. The mud line is assumed to be at a depth of 4000-ft TVD. The hole is cased to a depth of 16,000-ft TVD from surface by the previous casing. The target depth is at 20,000-ft TVD.

The pressure window shown in Figure 10.4 indicates that a mud weight of 11.4 ppg is sufficient to drill the required window with the help of dual-gradient MPD variation. To drill the same depth window using the conventional technique, two mud weights, 8.5 ppg and 9.0 ppg, are required; and the hole has to be cased at some depth between 17,000 and 17,600 ft. The path that has to be followed using the conventional drilling technique has been indicated with the help of arrows. A safety margin of 100 psi is held on both P_p and P_f , as mentioned earlier. The open-hole section is from 16,000- to 20,000-ft TVD.

Table 10.3 shows the annular pressure data under static and dynamic conditions for the given hole section. The pressures for all three mud weights are indicated. The mud circulation rate used for these simulations is 250 gpm.

In Figure 10.5, the complete pressure regime is shown. The sub-sea mud pump placed at 4000 ft adds energy enough to lift returns to the surface.

So, the given section can be drilled using a single mud weight of 11.4 ppg (1.37 spg) by maintaining a 475-psi (3275 kPa) back pres-

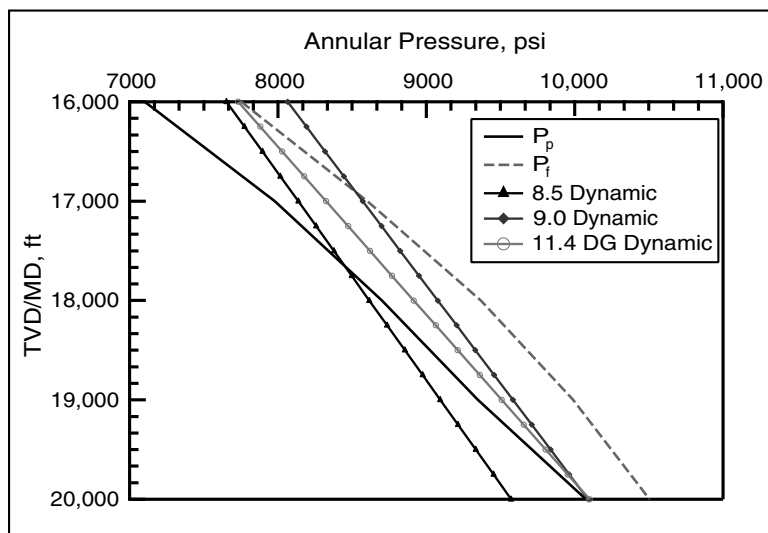


Figure 10.4 Dynamic pressure in the dual-gradient variation, zoomed section view.

sure at the mud-lift pump's suction. The annular dynamic pressure when circulating 8.5- and 9.0-ppg (1.02–1.08 spg) mud is also shown in the plot. Note that the required pressures at the suction and delivery of the pump change with the pipe internal diameter, friction factor, and water depth.

Figures 10.6 and 10.7 show the hydrostatic pressures in the annulus. The open-hole section is enlarged and shown in Figure 10.6. Note that this section can be drilled using conventional methods only by casing the open hole somewhere between 17,000 and 17,600 ft. So, when drilling the upper section with 8.5-ppg mud, a back pressure of 675 psi is required at the surface; and while drilling the lower section with 9.0-ppg mud, an 800-psi back pressure is required. The complete plot of the annular pressure in static condition is shown in Figure 10.7. The subsea mud pump placed at 4000 ft adds energy enough to lift returns to the surface. Note that S stands for static and D stands for dynamic in the figures.

Table 10.3 Annular Pressure Data under Static and Dynamic Conditions

Pressure Window			8.5 ppg (psi)		9.0 ppg (psi)		Solution: 11.4 ppg (psi)	
TVD (ft)	$P_p + SF$	$P_f - SF$	Static Pressure	Dynamic Pressure	Static Pressure	Dynamic Pressure	Static Pressure	Dynamic Pressure
Sea								
0	100	-100	675	0	800	0	0	0
4000	100	-100	2441	1899	2670	2003	2407	2369
Cased Hole								
4000	100	-100	2441	1899	2670	2003	475	625
8000	1936	3025	4208	3799	4541	4006	2882	2994
12,000	3708	5127	5974	5718	6411	6028	5288	5363
14,000	5859	6779	6857	6684	7346	7045	6494	6548
16,000	7102	7753	7741	7653	8281	8065	7700	7732
Open Hole								
16,000	7102	7753	7741	7653	8281	8065	7700	7732
17,000	7978	8603	8182	8138	8749	8576	8303	8324
18,000	8702	9368	8624	8616	9216	9080	8907	8917
19,000	9347	9989	9065	9095	9684	9585	9511	9509
20,000	10,075	10,505	9507	9575	10,151	10,090	10,115	10,101

SF = safety factor.

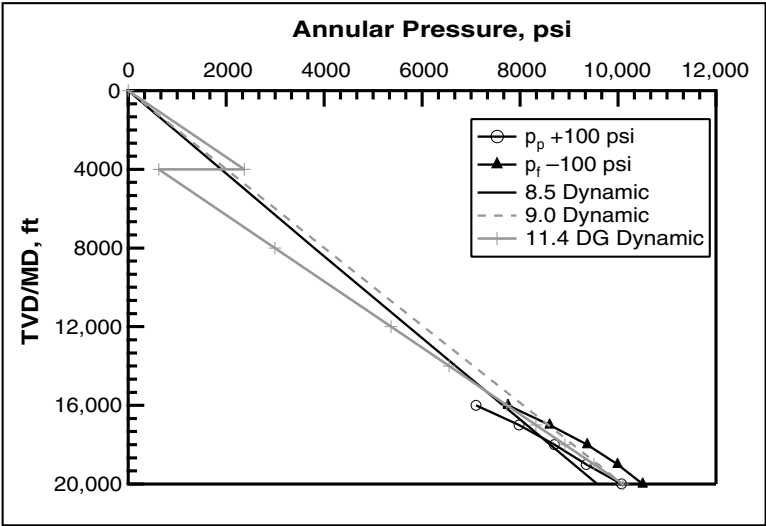


Figure 10.5 Dynamic pressure in dual-gradient variation, full-section view.

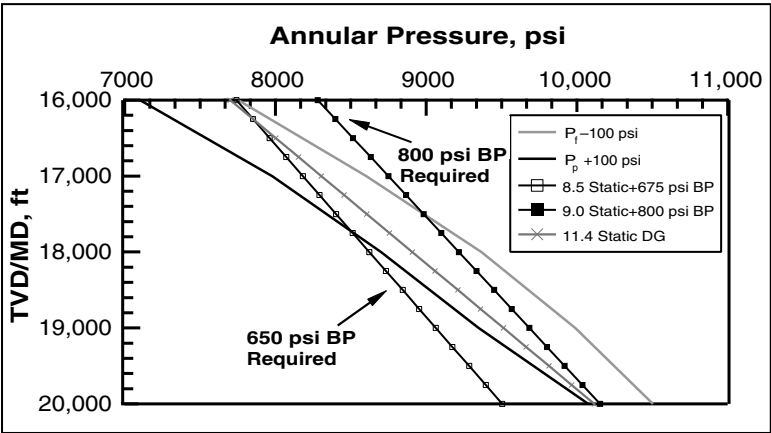


Figure 10.6 Hydrostatic-pressure plot showing just the open-hole section.

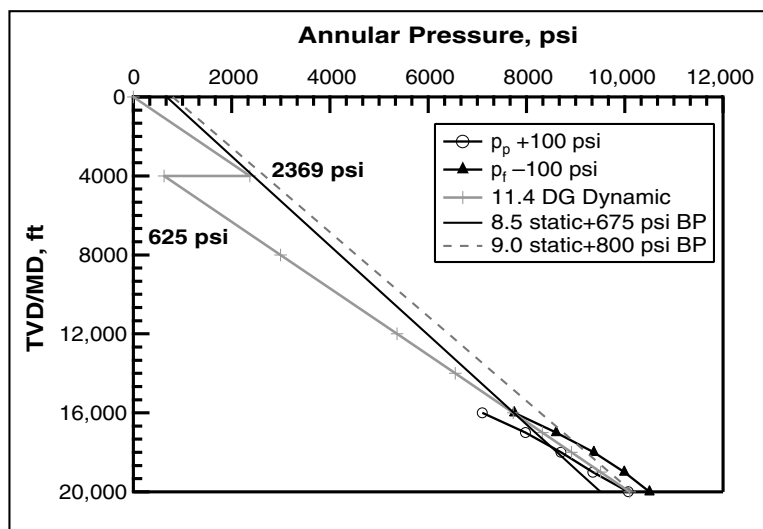


Figure 10.7 The complete plot of the annular pressure under the static condition.

Questions

1. What steps are involved in both candidate selection or feasibility study?
2. Every candidate analysis requires a minimum amount of information to yield a reasonable assessment. List the essential data parameters.
3. List the essential equipment for the successful implementation of MPD.
4. What optional equipment may be required for successful MPD operations?
5. Define and briefly describe HAZID.
6. Define and briefly describe HAZOP.

Answers

1. The steps involved are
 - Defining, identifying, and establishing the purpose.
 - Procuring information.
 - Performing a hydraulic analysis.
 - Selecting the method.
 - Determining the viability of MPD using a preliminary economic case (optional).
 - Recommending equipment (optional),
 - Performing HAZOP and HAZID (optional).
2. The minimum amount of information to yield a reasonable assessment include:
 - Pressure regimes: P_p and P_f , formation stability limits, and desired operating or working limits (if different from P_p , P_f , and FS).
 - Type of drilling problems or drilling issues to be overcome.
 - Drill-string and bottom-hole assembly details: Available alternative drill pipe on the rig or with the drilling contractor and detailed BHA design.
 - Mud design and properties: Type of mud and its rheological properties.
 - Well-bore geometry: Casing design details, especially details of the innermost casing, bore-hole diameters exposed to the drilling process for the interval in question, and directional targets, constraints, or plans.
3. The essential equipment are the
 - Rotating control device.
 - MPD choke.
 - Pressure monitoring software.
4. The optional equipment are the
 - Back-pressure pump, CBHP variation.
 - PWD tool (improves the application of pressure).

- CCS (depending on the application).
 - Drill-string floats (highly recommended).
5. HAZID, short for hazard identification, may consist of a simple list of anticipated problems to be encountered during MPD operations. The identification process helps in determining requirements and limitations of many of the other parameters mentioned earlier.
 6. HAZOP is short for hazard and operability. A more detailed HAZOP plan can include preliminary required procedures to avert or mitigate the hazards identified at this stage. This contingency plan may reveal additional aspects of the operation that can bring into question the viability or applicability of MPD for a particular well. For instance, a required procedure identified may result in an equipment requirement that cannot be met for the given well. If an alternative cannot be found, MPD may be eliminated as an option. On the other hand, certain contingency procedures may result in elimination of a particular equipment requirement, improving the applicability or feasibility of MPD.

APPENDIX A

Rock Mechanics

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A.1 Stress and Strain (Elastic and Nonelastic Deformation)

Flow-back, well ballooning, and leak-off tests are a function of rock elasticity and deformation. The flow-back from a well, normally called *well-bore ballooning*, is a major cause of nonproductive time during drilling operations, especially in the marine environment; so, it is important to understand some of the basics of this problem.

When the applied load to the rock is removed and the rock returns to its original physical state with no permanent damage, the rock is considered to behave in an elastic manner. The behavior can be defined based on a linear characterization of the loading curve in the load/displacement relationship. Elastic rock properties are categorized as static and dynamic. Static elastic parameters, which may also be known as *quasi-static parameters*, are usually obtained from the laboratory tests. Dynamic elastic parameters, on the other hand, are determined from the measurement of wave velocity in the rock. In an ideal elastic rock, the static and the dynamic parameters are the same.

For the static condition, the slope between the load intensity and normal strain is defined as the elastic modulus, also referred as *Young's modulus of the material*. Young's modulus simply relates the axial strain to axial stress for isotropic, linearly elastic materials. The static Young's modulus is proportional to the stiffness of the rock; and the higher the Young's modulus, the harder it is to deform the rock under uniaxial loading. The expression for Young's modulus is given by

$$E = \frac{\sigma}{\varepsilon} = 2G(1 + \nu) \quad (\text{A.1})$$

where

E = static Young's modulus

σ = normal stress

ε = strain

ν = Poisson's ratio

G = shear modulus

Experiments have shown, for a given isotropic material, the change in length per unit length of line elements in the perpendicular or transverse direction is a fixed fraction of the normal strain in the loaded direction. Hence, for a given material, the ratio of latitudinal to longitudinal strain is a constant, Poisson's ratio. Poisson's ratio is an elastic constant that is a measure of the compressibility of material perpendicular to applied stress. In static measurements, Poisson's ratio relates the axial strain to transversal normal strain as

$$\nu = - \frac{\varepsilon_{\text{tr}}}{\varepsilon_a} \quad (\text{A.2})$$

where

ε_{tr} = transverse strain

ε_a = axial strain

ν = Poisson's ratio

Generally, the value of the Poisson's ratio ranges between 0 and 0.5.

Two other useful moduli are the shear modulus, G , and the bulk modulus, K . The shear modulus arises from linear elasticity and is not easy to measure. Hence, the shear modulus is generally computed from Young's modulus (E) and Poisson's ratio (ν). The bulk modulus is the ratio of hydrostatic pressure to the volumetric strain it produces. The value of K is related to E and ν through

$$K = \frac{E}{3(1 - 2\nu)} \quad (\text{A.3})$$

The bulk modulus can be measured in the laboratory by measuring the volume change during a hydrostatic compression. The reciprocal of K is known as the *compressibility*. The compressibility of the rock is a major factor in poroelastic calculations.

Using the rock's dynamic properties, measured by logging techniques, some important rock mechanical constants can be determined. Using the compressional and shear wave velocities through the rock, Poisson's ratio can be given by

$$\nu = \frac{(V_c^2 - 2V_s^2)}{2(V_c^2 - V_s^2)} \quad (\text{A.4})$$

where

V_c = compressional wave velocity

V_s = shear wave velocity

Using the density log data, Young's modulus is obtained as

$$E = \rho v^2 \left[\frac{(3V_c^2 - 4V_s^2)}{(V_c^2 - V_s^2)} \right] \quad (\text{A.5})$$

Also, the shear modulus and the bulk modulus can be calculated as

$$G = \rho V_s^2 \quad (\text{A.6})$$

$$K = \rho \left[V_c^2 - \frac{4V_s^2}{3} \right] \quad (\text{A.7})$$

A.2 Horizontal and Vertical Rock Stress

Generally, in a simple rock fracturing model, it is assumed that the material is in a confined linear-elastic state with respect to vertical overburden load (Figure A.1). In isotropic materials, the magnitude of the axial strain and the transverse strain are the same. Hence, the horizontal strain can be used to generalize both axial and transverse strain:

$$\epsilon_H = \epsilon_a = \epsilon_{tr} \quad (A.8)$$

where

ϵ_H = horizontal strain

ϵ_a = axial strain

ϵ_{tr} = transverse strain

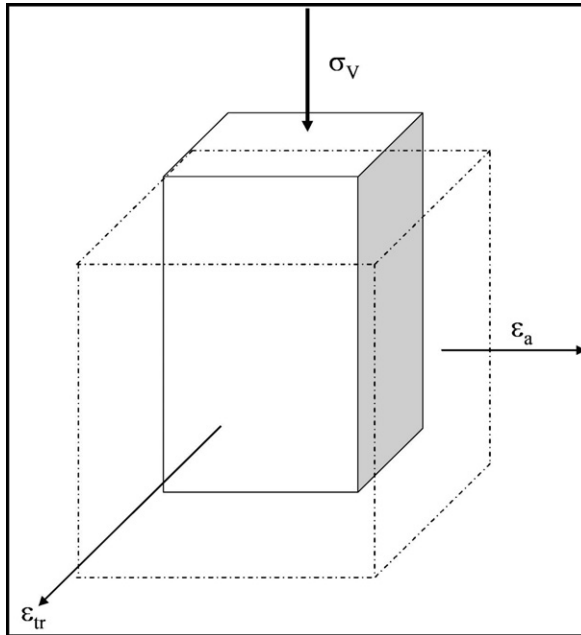


Figure A.1 Transverse reaction strain for a confined linear-elastic material.

Considering that, for a confined linear-elastic and isotropic material, the horizontal stress is a function of Poisson's ratio and vertical stress, the relationship between the overburden and horizontal stresses can be further expressed as

$$\sigma_H = \left(\frac{\nu}{1-\nu} \right) (\sigma_{ob} - P_p) + P_p \quad (\text{A.9})$$

where

σ_H = horizontal stress

ν = Poisson's ratio

P_p = pore pressure

σ_{ob} = overburden stress

Equation A.9 shows that, when Poisson's ratio is equal to or less than 0.5, the horizontal stresses always are less than or equal to the overburden stress. This is considered to be a basis of prediction of the theoretical fractured plane and its perpendicular nature to the minimum principal stress.

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APPENDIX B

Rheology

B.1 Introduction

Rheology is the study of the deformation and flow of matter. The flow characteristics of fluids depend highly on the rheology. Most drilling fluids are dispersions or emulsions with a complex rheology. Rheology is concerned mainly with the relationship of shear stress and shear rate.

Making certain measurements on a fluid leads to describing the fluid's flow behavior under a variety of temperatures, pressures, and shear rates. Evaluation of drilling fluids' rheological properties is considered a key factor in addressing the challenges associated with cuttings transport, erosion, fluids treatment, and hydraulics calculations.

B.2 Shear Stress and Shear Rate

In a flowing fluid, a force existing in the fluid that opposes the flow is known as the *shear stress*. The *shear stress* can also be defined as a force per unit area between two layers of fluids sliding by each other. The shear is more likely to occur between two layers of fluid than between the fluid's outer layer and the pipe's wall. This is why the fluid in contact with the pipe's wall does not flow. Accordingly, the force per unit area required to sustain a constant rate of fluid movement, the shear stress, is defined as

$$\tau = \frac{F}{A} \quad (\text{B.1})$$

where

τ = shear stress

F = force

A = area in contact with the fluid subjected to the force

When one layer of fluid passes over an adjacent layer, the rate of change of velocity is termed the *shear rate*. The shear rate, the velocity gradient measured across the length of a fluid's flow channel, is expressed as

$$\gamma = \frac{V_A - V_B}{h} \quad (\text{B.2})$$

where

γ = shear rate

V_A = velocity at layer A

V_B = velocity at layer B

h = distance between the layers A and B

The pressure loss in a circulating system, the pump pressure, and the flow rate of a circulating system, the pump rate, can be linked to the shear stress and the shear rate, respectively. The shear rate of a flowing fluid is associated with the average velocity of the fluid in the flow channel and the dimension of passage (wetted diameter). Hence, a fluid flowing in small geometries, such as inside the tubing, has a higher shear rate than a fluid flowing in large geometries, such as casing or riser annuli. In general, for a fluid, the relationship between the shear rate and the shear stress determines how that fluid flows.

B.3 Newtonian Model

When the viscosity of a fluid, at constant temperature and pressure, does not depend on the shear rate, the fluid is classified as a Newtonian fluid. In other words, the plot of shear stress versus shear rate of a Newtonian fluid (Figure B.1) yields to a straight line that passes through the origin of the plot coordinates. The slope of this

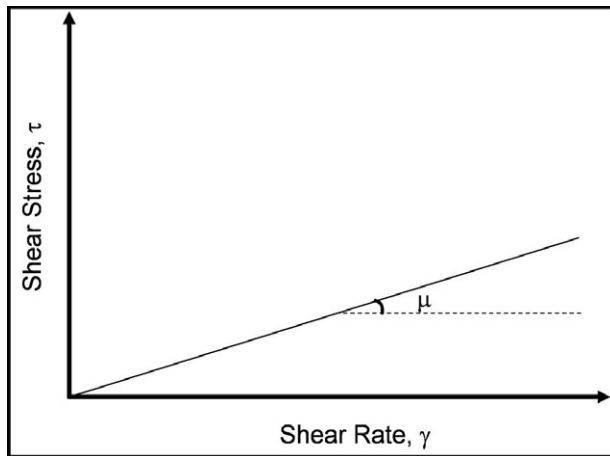


Figure B.1 Plot of shear stress versus shear rate of a Newtonian fluid.

straight line is called the *Newtonian viscosity of the fluid*. The correlation describing a Newtonian fluid can be expressed as

$$\tau = \mu \times \gamma \quad (\text{B.3})$$

The Newtonian behavior of the fluids can be classified as the simplest flow behavior of the fluids. Many of the base fluids, such as water, oils, and synthetics, behave as Newtonian fluids.

B.4 Non-Newtonian Model

In non-Newtonian fluids, unlike the Newtonian fluids, there is no direct proportionality between the shear stress and shear rate. The viscosity of such fluids depends on the shear rate; and at different shear rates, because of different shear stress/shear rate ratios, the viscosity is not a constant value. This means that a non-Newtonian fluid has no single or constant viscosity that describes the fluid behavior at different shear rates (Figure B.2).

Many fluids are too complex to be characterized by a single value for their viscosity. Hence, to describe the viscosity of a non-Newtonian

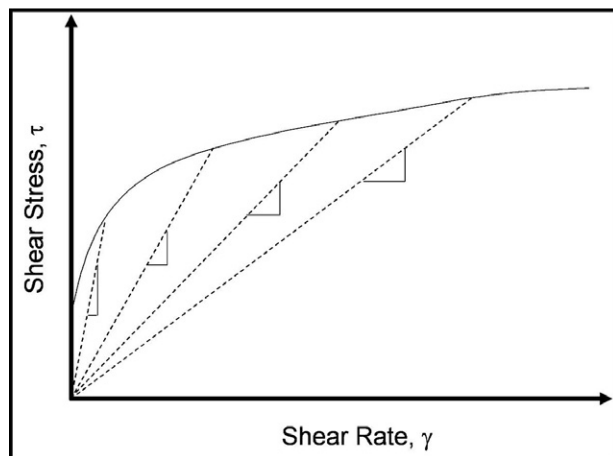


Figure B.2 Plot of shear stress versus shear rate of a non-Newtonian fluid.

fluid at a particular shear rate, apparent viscosity and effective viscosity are defined. Apparent viscosity is one-half the 600-rpm reading. Effective viscosity is defined as the shear stress/shear rate ratio of a fluid at a particular shear rate.

When the viscosity decreases with increasing the shear rate, the fluid behavior is categorized as shear thinning. These types of the fluids are also known as *pseudoplastic fluids*. Most of the non-Newtonian fluids exhibit such a behavior. However, in a few cases, the effective viscosity increases with the shear rate. Such behavior is generally described as shear thickening, and these types of fluids are categorized as dilatant fluids.

So far, it is assumed that, at a given shear rate, as long as the shear rate is kept constant, the corresponding shear stress remains constant. However, in many cases, the shear stress and hence the viscosity either increases or decreases with time. If the viscosity of a non-Newtonian fluid increases with time after the shear rate is increased to a new constant value, the fluid is known as *thixotropic*. The opposite type of fluids are called *antithixotropic* or *rheopectic fluids*.

B.4.1 Bingham Plastic Model

The Bingham plastic model is known to be the first two-parameter model used most often to describe the flow characteristics of drill-

ing fluids. The Bingham plastic model assumes a linear relationship between the shear stress and the shear rate (Figure B.3). This model describes a fluid behavior in which there is no flow until the applied shear stress exceeds a certain minimum value. The finite shear stress required to initiate the flow is called the *yield point*. When the yield point is reached, changes in the shear stress are proportional to changes in the shear rate. The constant of proportionality in which fluid exhibits a constant viscosity with an increasing shear rate is called the *plastic viscosity*. The Bingham plastic model can be expressed as

$$\tau = \mu_p \gamma + \tau_y \quad (\text{B.4})$$

where

μ_p = plastic viscosity

τ_y = yield point

The plastic viscosity and the yield point can be read either from the associated graphs or calculated by correlations. For typical oil-field viscometers like the Fann viscometer, the following correlation is used:

$$\mu_p = R_{600} - R_{300} \quad (\text{B.5})$$

$$\tau_y = R_{300} - \mu_p \quad (\text{B.6})$$

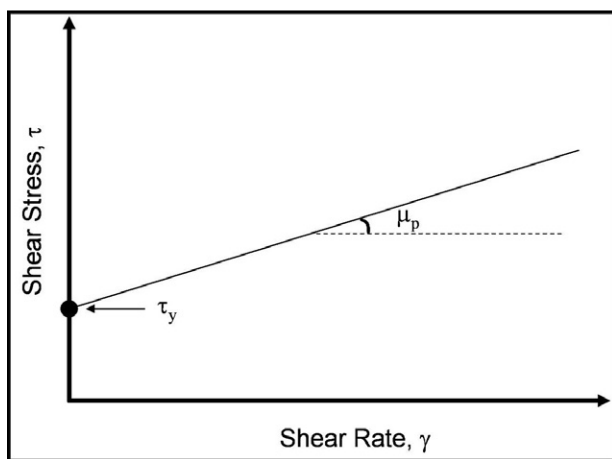


Figure B.3 Plot of shear stress versus shear rate of a Bingham plastic fluid.

where

R_{600} = viscometer reading at 600 rpm

R_{300} = viscometer reading at 300 rpm

Note that the behavior of the drilling fluids at very low shear rates cannot be accurately predicted by this model. Therefore, pressure loss calculations are not very accurate when the Bingham plastic model is used. However, this model is very useful for monitoring and treating, because it separates out the effect of solids, plastic viscosity, electrochemical contamination, and the yield point.

B.4.2 Power Law Model

Like the Bingham plastic model, the power law model is a two-parameter model for fluid characterization. The power law model attempts to address the flaws of the Bingham plastic model at low shear rates. The power law model assumes a nonlinear relationship between the shear stress and the shear rate. Mathematically, the power law model describes fluid behavior in which the shear stress increases as a function of the shear rate raised to a power of a constant value (Figure B.4). The power law model is then defined as

$$\tau = K \times \gamma^n \quad (\text{B.7})$$

where

K = consistency index, $\text{lb s}^n/100 \text{ ft}^2$

n = flow behavior index

The power law parameters can be estimated as

$$K = \frac{5.11R_{300}}{511^n} \quad \text{or} \quad K = \frac{5.11R_{600}}{1022^n} \quad (\text{B.8})$$

$$n = 3.32 \log \left(\frac{R_{600}}{R_{300}} \right) \quad (\text{B.9})$$

The *consistency index* is defined as the viscosity at a shear rate of 1/sec, and it is also related to the viscosity at low shear rates. Increasing the consistency index could improve the fluid's hole-cleaning potential.

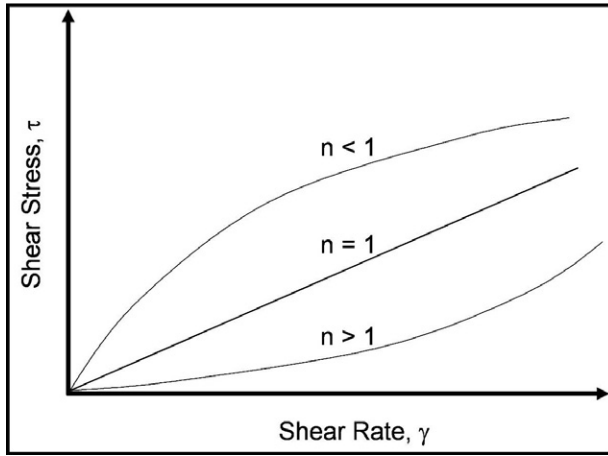


Figure B.4 Plot of shear stress versus shear rate of a power law model.

The flow behavior index characterizes a fluid's degree of non-Newtonian behavior over a given shear rate range. Depending on the deviation of the flow behavior index from unity, three types of fluid behavior could exist:

1. $n < 1$: non-Newtonian pseudoplastic fluids (shear thinning).
2. $n = 1$: Newtonian fluids.
3. $n > 1$: non-Newtonian dilatant fluids (shear thickening).

Taking logarithm of both sides of the basic power law equation yields

$$\log(\tau) = \log(K) + n \log(\gamma) \quad (\text{B.10})$$

Based on Eq. B.10, the logarithmic plot of the shear stress versus the shear rate (Figure B.5) forms a straight line in which the slope of the line is the flow behavior index and the consistency index is the intercept. Note that, for power law fluids similar to Newtonian fluids, the plot of shear stress versus shear rate passes through the origin.

Although the power law model is more accurate in low shear rate conditions, it is not yet reliable at high shear rates.

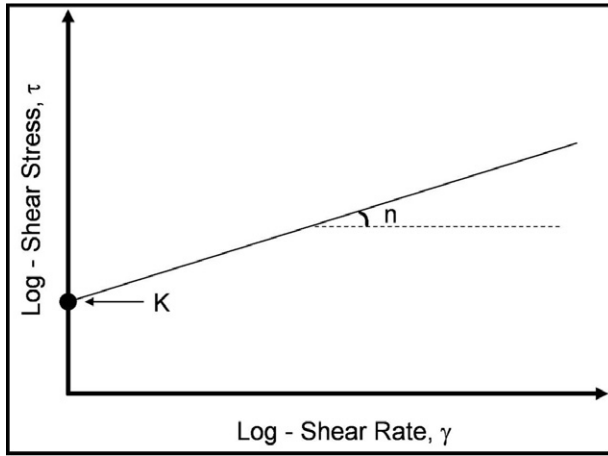


Figure B.5 Logarithmic plot of shear stress versus shear rate of a power law fluid.

B.4.3 API (Recommended Practice 13D, 2003) Model

Since 1995, American Petroleum Institute (API) has recommended using a modified power law model. API recommended a model in 2003. In this model, the shear rate readings from the viscometer are associated with the actual shear rate values inside the drill pipe and annulus. For instance, inside the pipe, where high shear rates are expected, the readings at 300 and 600 rpm are used to correlate K and n as

$$K_{\text{pipe}} = \frac{5.11R_{600}}{1022^{n_{\text{pipe}}}} \quad (\text{B.11})$$

$$n_{\text{pipe}} = 3.32 \log \left(\frac{R_{600}}{R_{300}} \right) \quad (\text{B.12})$$

And, for the annulus, where low shear rates are expected,

$$K_{\text{annulus}} = \frac{5.11R_{100}}{170.2^{n_{\text{annulus}}}} \quad (\text{B.13})$$

$$n_{\text{annulus}} = 0.657 \log \left(\frac{R_{100}}{R_3} \right) \quad (\text{B.14})$$

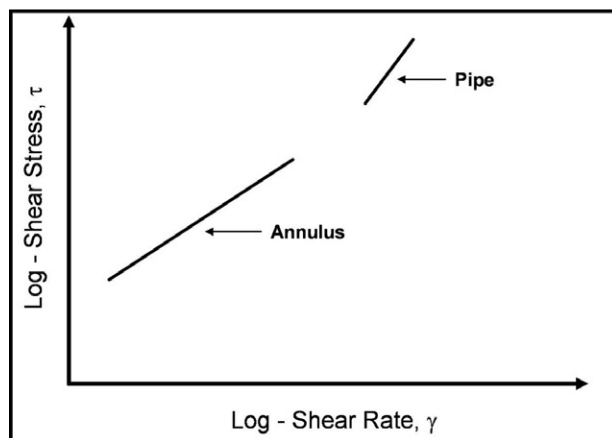


Figure B.6 Logarithmic plot of shear stress versus shear rate of a dual-power law fluid.

As Figure B.6 shows, based on the “dual-power law” model, the lower shear rate values at the annulus are distinctly separated from the higher shear rate values at the pipe. Note that, in this model, the yield stress, which is a critical aspect of cuttings removal, barite sag, suspension, and some other drilling issues, is not considered.

B.4.4 Herschel–Bulkley Model

The latest version of API 13D recommends the Herschel–Bulkley model. Unlike the Bingham plastic and the power law models, which employ two parameters, the Herschel–Bulkley model exploits three parameters to characterize the flow behavior. Compared to the power law or the Bingham plastic model, when adequate experimental data are available, the Herschel–Bulkley model is an accurate, more desirable model. Mathematically, the model can be expressed as

$$\tau = \tau_0 + K \times \gamma^n \quad (\text{B.15})$$

where, for $\tau > \tau_0$, the material flows as a power law fluid, and for $\tau < \tau_0$, it remains rigid.

Herschel–Bulkley parameters are determined through statistical analysis and curve fitting. However, parameters can be estimated

using measured data. The estimate of the fluid yield stress commonly known as low-shear-rate yield point is

$$\tau_y = 2\theta_{300} - \theta_{600} \quad (\text{B.16})$$

The fluid flow index value is estimated by

$$n = 3.32 \log_{10} \left(\frac{\theta_{600} - \tau_y}{\theta_{300} - \tau_y} \right) \quad (\text{B.17})$$

and the fluid consistency index is estimated by

$$k = \frac{\theta_{300} - \tau_y}{511^n} \quad (\text{B.18})$$

This is a short summary of rheology; and further, different equations and approaches are available trying to characterize fluid behavior under different conditions. API 13D provides practical recommendations to characterize drilling fluids and provide guidelines to calculate pressure drop. Bern et al. (2006) review the API Recommended Practice 13D and propose some modifications. Several other references are listed to provide more information on fluid rheology. Most of characterizations are valid for conventional drilling. More robust modeling and characterization is required to understand the fluid behavior for special drilling operations dealing with HTHP or low-temperature conditions.

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- Bourgoyne, A. T. Jr., Millheim, K. K., and Chenever, M. E. *Applied Drilling Engineering*. Richardson, TX: Society of Petroleum Engineers, 1986.
- MI Drilling Fluids Engineering Manual*. MI, 1998.

APPENDIX C

Useful Conversion Factors

Parameter	Field Unit	SI Unit	Conversion Factor, Field Unit to SI Unit
Acceleration	Feet/square second	Meter/square second	0.3048
Area	Square feet	Square meter	0.0929
	Square inch	Square meter	6.45×10^{-4}
Cake thickness	$\frac{1}{32}$ inch	Millimeters	0.793
Concentration	lb _m /bbl	Kilogram/cubic meter	2.85
	lb _m /gal	Kilogram/cubic meter	119.8
Density	lb _m /cubic feet (pcf)	Kilogram/cubic meter	16.02
	lb _m /gal (ppg)	Kilogram/cubic meter	119.8
Diameter	Inches	Millimeter	25.4
Drilling rate	ft/hr	Meters/hour	0.3048
Flow rate	bbl/min	Cubic meters/min	0.159
	bbl/stroke	Cubic meters/stroke	0.159
	gal/min	Cubic meters/min	3.785×10^{-3}
	gal/stroke	Cubic meters/stroke	3.785×10^{-4}

Parameter	Field Unit	SI Unit	Conversion Factor, Field Unit to SI Unit
Fluid loss	Milliliters (mL or CC)	Milliliters (mL or CC)	1
Force	Pound force (lb _f)	Newton	4.448
Gels strength	lb _f /100 ft ²	Pascals	0.479
Length	Feet	Meters	0.3048
	Inches	Millimeter	25.4
	Microns	Micrometer	1
Marsh funnel viscosity	Seconds/quart	Seconds/liter	1.06
Mass	lb _m	Kilogram	0.4536
MBT	lb _m /bbl	Kilogram/cubic meter	2.85
Nozzle size	$\frac{1}{32}$ inch	Millimeters	0.794
Pressure	psi	Kilopascals	6.895
	psi	Megapascals	6.895×10^{-3}
Rotation speed	Revolutions/ minute	Revolutions/ minute	1
Shear rate	Reciprocal/ seconds	Reciprocal/ seconds	1
Temperature	°F	°C	$(^{\circ}\text{F} - 32)/1.8$
Torque	Foot pounds	Kilonewton meter	1.356×10^{-3}
	Foot pounds	Newton meter	1.356
	Inch pounds	Kilonewton meter	1.13×10^{-4}
	Inch pounds	Newton meter	0.113
Velocity	Feet/min	Meter/min	0.3048
	Feet/sec	Meter/sec	0.3048
Viscosity	Centipoises	Millipascal seconds	1

Parameter	Field Unit	SI Unit	Conversion Factor, Field Unit to SI Unit
Volume	Barrels (bbl)	Cubic meter	0.159
	Barrels (bbl)	Liter	159
	Gallons (gal)	Cubic meter	3.785×10^{-3}
	Gallons (gal)	Liter	3.785
	Standard cubic feet (scf)	Cubic meter	2.83×10^{-2}
	Standard cubic feet (scf)	Liter	28.3
Volume/length	bbl/ft	Cubic meter/ meter	0.5216
	Cubic feet/ft	Cubic meter/ meter	0.0929
Yield of bentonite	bbl/ton	Cubic meter/ton	0.175
Yield point	lb _f /100 ft ²	Pascals	0.479

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APPENDIX D

IADC Well Classification System for Underbalanced Operations and Managed Pressure Drilling



IADC Well Classification System for Underbalanced Operations and Managed Pressure Drilling

The purpose of the IADC Well Classification System is to describe the overall risk, application category and fluid system used in underbalanced operations (UBO) and managed pressure drilling (MPD). Wells are classified according to:

- **Risk Level** (0 to 5)
- **Application Category** (A, B or C)
- **Fluid System** (1 to 5).

This classification system provides a framework for defining minimum equipment requirements, specialized procedures, and safety management practices. For further information refer to the IADC UBO HSE Planning Guidelines and other related documents.

Risk Levels

Generally, risk increases with operational complexity and potential well productivity. The examples provided are for guidance only.

Level 0 – Performance enhancement only; no hydrocarbon containing zones.

- Air drilling for ROP enhancement

Level 1 – Well incapable of natural flow to surface. Well is inherently stable and is a low level risk from a well control point of view.

- Sub-normally pressured oil wells

Level 2 – Well is capable of natural flow to surface, but can be controlled using conventional well kill methods. Catastrophic equipment failure may have limited consequences.

- Abnormally-pressured water zones
- Low flow rate oil or gas wells
- Depleted gas wells

Level 3 – Geothermal and non-hydrocarbon bearing formations. Maximum anticipated shut-in pressure (MASP) is less than UBO/MPD equipment pressure rating.

- Includes geothermal wells with H₂S present

Level 4 – Hydrocarbon bearing formation. Maximum anticipated shut-in pressure is less than UBO/MPD equipment operating pressure rating. Catastrophic equipment failure will likely have immediate serious consequences.

- High pressure and/or high flow potential reservoir
- Sour oil and gas wells
- Offshore environments
- Simultaneous drilling and production operations

Level 5 – Maximum anticipated surface pressure exceeds UBO/MPD equipment operating pressure rating. Catastrophic equipment failure will likely have immediate serious consequences.

- Any well where MASP is greater than UBO/MPD equipment pressure rating

Application Category

Category A – Managed Pressure Drilling (MPD) – Drilling with returns to surface using an equivalent mud weight that is maintained at or above the open-hole pore pressure.

Category B – Under balanced Operations (UBO) – Performing operations with returns to surface using an equivalent mud weight that is maintained below the open-hole pore pressure.

Category C – Mud Cap Drilling – Drilling with a variable length annular fluid column which is maintained above a formation that is taking injected fluid and drilled cuttings without returns to surface.

Fluid Systems

1. Gas – gas as the fluid medium. No liquid intentionally added.
2. Mist – fluid medium with liquid entrained in a continuous gaseous phase. Typical mist systems have less than 2.5% liquid content.
3. Foam – two-phase fluid medium with a continuous liquid phase generated from the addition of liquid, surfactant, and gas. Typical foams range from 55% to 97.5% gas.
4. Gasified Liquid – fluid medium with a gas entrained in a liquid phase.
5. Liquid – fluid medium with a single liquid phase.

Example:

A well is being drilled from 10,000 feet to 12,000 feet utilizing managed pressure drilling techniques. The pore pressure of the formation is 14.5 ppg and the fracture gradient is 16.5 ppg. The design is predicated on using a 13.0 ppg fluid and maintaining a balanced system with surface pressure. The rotating control device (RCD) and emergency shutdown (ESD) systems are rated at 5000 psi.

From the above information:

MASP is the lesser of BHP minus gas to surface or frac at shoe minus gas to surface.

$MASP_{BHP} = 12000 \times 0.052 \times (14.5-2) = 7800 \text{ psi}$

$MASP_{fc} = 10000 \times 0.052 \times (16.5-2) = 7540 \text{ psi}$

As the maximum anticipated surface pressure exceeds the UBO/MPD equipment rating, the classification for the well would be:

Level 5, Category A, Fluid System 5 or 5A5.

Adopted by the IADC Board of Directors, 9 March 2005.

APPENDIX E

IADC Underbalanced and Managed Pressure Drilling Guidelines—HSE Planning Guidelines



UNDERBALANCED AND MANAGED PRESSURE DRILLING OPERATIONS

- HSE PLANNING GUIDELINES -

Original Written and Compiled by: John Ramalho and Roger Catchpole
Date: June 2001 **Issue:** December 2002

Revision 01- Written and Compiled by: Adrian Houlbrook and Angus Lyon
Date: January 2006 **Issue:** January 2007

FOREWORD

These Guidelines have been prepared on behalf of the IADC Underbalanced Operations and Managed Pressure Drilling (UBO & MPD) Committee by its Training/Health, Safety, and Environment Subcommittee. The mission of this Committee is to "promote the safe and efficient execution of underbalanced and managed pressure drilling operations worldwide." It is intended for use by integrated project teams involved in the design and implementation of underbalanced and managed pressure drilling operations. It provides information and guidance on HSE related activities in the planning phases of an underbalanced drilling operation (UBO) or managed pressure drilling (MPD) project, which have an impact on the hazards and risks of the operation during the execution phase and therefore require detailed care and attention. The principles and recommendations have general relevance, regardless of classification and are applicable to both onshore and offshore UBO/MPD operations.

While these Guidelines offer definite recommendations, they should be considered as a starting point for the Operating Company (OPCO), Drilling Contractor, and UBO/MPD Service Contractor in developing their own UBO/MPD Safety Management programs and associated operational plans and procedures. Each Operator and the Service Contractors involved in the UBO/MPD project should review and apply the Guidelines according to its own policies and experience for the particular area and the appropriate risk level of the operation. For simplicity, the approach taken is to utilize a generic HSE Management System to convey the important aspects of Safety Management and then describe how each part applies to HSE management within the UBO or MPD project. However, the principles of safety management as they apply to a UBO or MPD project will be similar, regardless of the Safety Management System model the Operating Company and/or the Service contractors are using.

In the national and local areas currently drilling wells offshore using UBO or MPD techniques, statutory requirements, rules, and regulations may apply to the activities conducted on these wells. In such situations, apply the Guidelines as complementary to the regulatory requirements but without supplanting them. In conjunction with the Guidelines, a review and application of the Codes, Specifications, Recommended Practices, and Standards referenced herein is essential. In addition, account should be taken of changes in Codes of Practice, Specifications, Standards, National Statutory Requirements, and Regulations that may have been issued since these Guidelines were published.

It must be stressed that the successful implementation of these Guidelines and the outcome from the planning process will depend largely on the attitudes and manner in which safety awareness is developed among the personnel concerned.

The Guidelines use a number of terms, acronyms, and abbreviations that are in common use in the Oil and Gas Industry. A glossary of terms with appropriate definitions, is available on the IADC website. A link to the website is provided in the Appendix. These apply irrespective of any other meaning the words may have in any other context.

Although the adoption of these Guidelines should help to promote HSE principles in the planning and execution of underbalanced or managed pressure drilling operations, IADC and its UBO/MPD Committee cannot accept responsibility in any way for injury to personnel or damage to equipment, installations or property, which may occur where these Guidelines have been followed. Underbalanced and managed pressure drilling technology and associated regulations are developing continuously and Operating Companies and others should ensure they remain up-to-date.

UB & MPD Operations – HSE Planning Guidelines

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UB & MPD Operations – HSE Planning Guidelines

1. Introduction

During the execution of drilling and testing operations, many of the activities have the potential for negative impact on the health and safety of workers, on the environment and/or on the equipment or installation being used. The potential for increased risk occurs whenever a new operation that is different from the normal activity is introduced. Such is the case of managed pressure or underbalanced operations on a drilling site. These operations are significantly different from the conventional drilling approach and frequently involve more than one organisation. To ensure a safe and efficient operation, the supervisors and crews executing these operations have to be familiar with the process, the equipment, the procedures and the HSE issues which should be based on consistent methods understood by all parties involved. Therefore, in setting up an Underbalanced Drilling Operation (UBO) or Managed Pressure Drilling (MPD) project, it is critical that the hazards and risks are considered from the very early phases of the project planning cycle as described in Figure 4.

To illustrate the use of the Guidelines it is assumed that a small company plans to drill a well using underbalanced or managed pressure operations techniques and references the IADC HSE Planning Guidelines. The issue to focus on and understand is that the intent of this document is to provide guidance for managing the hazards and risks in the planning phases.

The Guidelines first utilise a generic Health, Safety and Environmental Management System (HSE MS) structure to highlight and explain the areas that need to be focused on whilst planning a UBO or MPD Project. Secondly, by expanding on the planning and procedures part of the HSE MS, in a structured approach to show the various processes that should be followed, this document provides guidance in flowchart format, tables and recommended practices. Avoiding the potential negative impacts is, for the most part, achieved by the actions of personnel involved with the drilling project. The actions are based on the systems and procedures they follow. The applicable systems and procedures, how they are developed, maintained, implemented and how personnel are trained in their use constitutes an HSE Management System (HSE MS).

Our example company may or may not have a formal HSE MS. Therefore the following section is intended as a brief overview of an HSE MS and to highlight those sections that might impact the UBO or MPD Project Plan.

2. HSE Management Systems

When initiating an Underbalanced or Managed Pressure Drilling project, it is critical that HSE issues are considered from the very early phases of the project planning cycle. Implementing HSE MS principles aids the consideration.

The industry recognises that in national and local areas where wells are being drilled there will be statutory requirements, rules and regulations that apply to the activities to be conducted on these wells. The industry also recognises certain Standards, Codes and Recommended Practices. Figure 13 illustrates the various sources referenced when developing this guideline document. The aim has been to produce Guidelines which reflect the best practice from the sources consulted.

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A Company's HSE MS describes the way in which it will manage its stated HSE objectives. As in any management system, this is accomplished by focusing on key activities. This ensures that:

- ⇒ Critical activities are effectively controlled
- ⇒ Procedures and documentation are in place
- ⇒ Performance is measured and reported
- ⇒ Areas for improvement are identified.

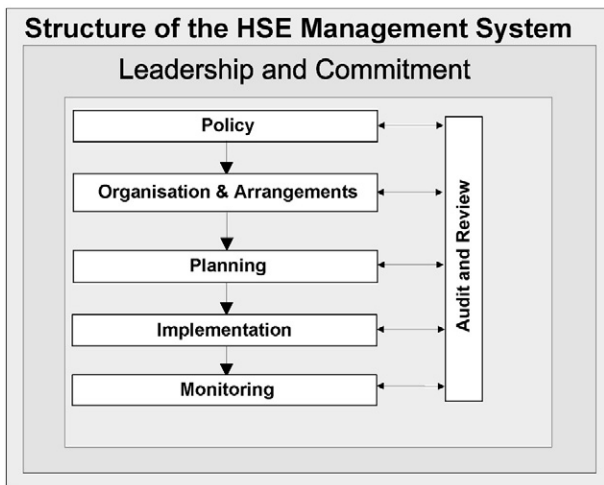


Figure 1- An example of the structure of an HSE Management System.

2.1. Leadership and Commitment

Leadership and commitment is the foundation for building a quality HSE MS. In order to ensure effective HSE processes in the workplace, there must be commitment from the top management of the company to provide the necessary time and resources for HSE related activities. This principle should apply regardless of the size of the company and/or area of operation.

This is especially critical in the planning of a UBO operation, since the risk and the consequence of failure can be significant.

2.2. Policy and Strategic Objectives

Policy statements and strategic objectives are set at the corporate level, then communicated down to departmental level and translated into roles and responsibilities. The HSE MS of many oil and gas operating and service companies may not specifically address the hazards and risks associated with the application of UBO/MPD Technology.

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However, conventional policy statements in the HSE MS would be such that they would:

Require the project team to be aware of the current hazards and risks associated with underbalanced or managed pressure drilling operations and

Be cognisant of the hazards and risks that may be introduced if proper HSE considerations are not included from the very early phases of the planning and design cycle.

In general, statutory requirements in operating areas and/or due-diligence will require this of any project team whether or not the companies involved have formal HSE Management Systems in place.

2.3. Organisation Structure, Responsibilities, Resources, Standards and Documentation

An HSE MS will address essential issues such as organisational structure, roles and responsibilities, resources, standards and documentation. It will also contain the framework to address issues specific to UBO/MPD technology such as:

Information gained from discussions and presentations at industry UBO/MPD forums.

An Operations Organisation Structure with well-defined roles and responsibilities for both office-based and field-based staff.

Making good HSE performance a key business objective. In addition to being the morally correct objective, today's business environment places an operating company's Licence to Operate under greater public scrutiny, further increasing the visibility of HSE performance. The degree of success of meeting any business objective, including good HSE performance, is dependent on the resources allocated to achieving that intent.

Standards and documentation, which are the building blocks of an HSE Management System. Underbalanced and managed pressure drilling are technologies that are gaining global acceptance. For the most part, corporate and industry standards covering the activities are lagging behind the implementation of the techniques. Furthermore, underbalanced and managed pressure drilling may compromise many existing standards and therefore a change to the standard or dispensation to deviate from those standards will be required.

Table 1 groups some of the Standards that form the core of an HSE MS and identifies the potential impact of UBO/MPD on the standard.

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TYPE	DELIVERABLE
Management standards	Set the framework in which the Company operates and deals with corporate policies, objectives, accountabilities and controls.
<i>UBO/MPD impact</i>	<i>No change</i>
Engineering, equipment and material standards	Set the standards by which equipment and materials are procured and by which the control of change is effectively managed.
<i>UBO/MPD impact</i>	<i>Specifications may be required for: Gas injection system; Surface separation system; Snubbing system; and Well stack-up system</i>
Working standards	Define the way in which day-to-day work is carried out, monitored and inspected. Include work procedures and particularly those that relate to HS&E critical activities.
<i>UBO/MPD impact</i>	<i>Standards will need to be developed for: UBO/MPD Operations UBO/MPD Tripping UBO/MPD Well Control.</i>
Competence standards	Describes the standards that need to be achieved in a variety of company / contractor work roles and how competency is assessed.
<i>UBO/MPD impact</i>	<i>Typically, Standards of Competence will be required for: Operator site supervisor Tool pushers Drillers Assistant Drillers Derrickmen UBO/MPD Supervisor UBO/MPD Engineers Well Engineering Project Co-ordinator Well Services Supervisor Snubbing Engineers Snubbing Supervisor Gas Injection Supervisor Surface Separation Supervisor</i>

Table 1 - HSE Management System Standards

2.4 Planning Overview and Hazard Management

A hazard register is a key document in a company's risk management process. For every process in the company, possible hazards will be identified along with the actions necessary to minimise the associated risks and documented in the register.

This requires an understanding of what a hazard is (a situation with the potential to cause harm) and a risk, the likelihood harm will occur multiplied by the consequences.

Incidents may start with relatively insignificant failures of equipment or the actions of people, which in combination with circumstances and the reactions of other equipment and people can escalate to release hazards, cause severe injuries, and/or damage to the environment and assets. The equipment failure and circumstances themselves are also generally the result of human or system failures long before the incident (e.g. during design, construction, planning etc.). The interactions between equipment, environment, and people are complex.

The "bow-tie" diagram (Figure 2) is a graphical way of presenting these interactions and the controls or barriers that can be put in place to stop the development of major events. Should an event occur, there are additional measures that can prevent escalation and mitigate the consequences. It can also help to explain the essence of the Hazard Management Process, which forms the core of HSE Management.

The "bow-tie" diagram combines the concepts of fault and event trees used in quantitative risk assessment. The left hand side of the diagram describes how events and circumstances, either in isolation or in combination, can release a hazard and lead to an undesired event with the potential of harm to assets, people, the environment, and ultimately the company's reputation. The right hand side represents the various scenarios that might develop from the undesired event, dependent on the effectiveness of systems and activities to stop progression to lasting harm and damage.

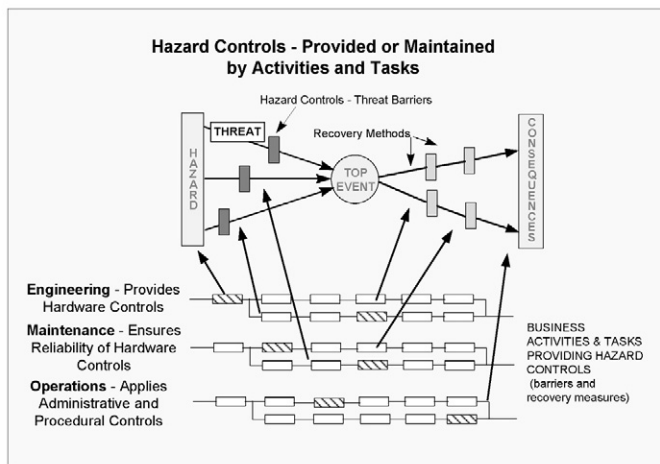


Figure 2 - Generic "Bow-tie" Diagram

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The barriers shown on the lines on the left-hand side pointing to the top event relate to the measures taken to prevent the circumstance or initiating incident from occurring. For each initiating event or circumstance, one or more barriers can be put in place, depending on their effectiveness and the potential severity of the consequences. The barriers on the right hand side represent measures and equipment to inhibit the event, if it occurs, from causing permanent harm and damage. This is often referred to as risk mitigation. Barriers can be hardware, instrumentation, procedures, competencies etc. Shown at the bottom of the diagram are the various types of activities necessary to recognise the need for the barriers, to put them in place, and to keep them effective.

The risk associated with a specific hazard is the product of the probability (likelihood) that the event will occur and potential severity of the consequence if the event occurs. One of the tools available to assist with high-level (qualitative rather than quantitative) risk assessment is a Risk Assessment Matrix (Figure 3). The diagram is generally used to evaluate HSE associated incidents but assessment of any type of failure is possible.

POTENTIAL CONSEQUENCES		PROBABILITY OF OCCURRENCE (increasing probability)				
		A	B	C	D	E
		Never heard of in the E & P industry	Has occurred in the E & P industry	Has occurred in the UBD industry	Likely to occur on this project	Likely to occur several times on this project
1	- People: Slight injury or health effects - Asset: Slight property damage < \$10,000 USD - Environment: Slight effect					
2	- People: Minor injury or health effects - Asset: Minor property damage < \$100,000 USD - Environment: Minor effect					
3	- People: Major injury or health effects - Asset: Localized damage < \$1,000,000 USD - Environment: Localized effect (onsite)					
4	- People: Single Fatality or permanent total disability - Asset: Major damage < \$10,000,000 USD - Environment: Major effect (offsite)					
5	- People: Multiple fatalities - Asset: Extensive damage > \$10,000,000 USD - Environment: Massive effect					

LOW RISK

MEDIUM RISK

HIGH RISK

DEFINITION OF AN INCIDENT: "An incident is an unplanned event or chain of events which has caused or could have caused injury, illness to People, and or damage (loss) to Assets, Environment"

Note: The values used in the matrix and the frequency are for example purposes only

Figure 3 – Example of typical Risk Assessment Matrix

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In simple terms whenever an incident or event (including a near-miss) occurs, there is a potential consequence. This can vary from little or no effect, to multiple fatalities or high cost events. As indicated before, risk is the product of the likelihood and the consequence of a hazardous event occurring. For example, if you cross a busy highway twice per day every day of the year, you are more likely (higher exposure - higher probability) to have an accident than your neighbour who only has to cross on the weekends (less exposure - lower probability). If a vehicle (the hazard) hits you while you are crossing the highway, you could be seriously injured or killed (the potential consequence)

The matrix plots the increasing consequence (1-5) of an event on a vertical scale against the probability (likelihood) of occurrence on a horizontal scale. Efficient, cost effective risk management evaluates both the likelihood of an event occurring and the potential consequences if it occurs, in deciding on the control mechanism.

For events evaluated to be low risk, training may be sufficient to control the hazard. Generally, an event evaluated to be medium risk would require a combination of training and procedures to control it. However, high-risk events will likely require engineered solutions in addition to training and procedures to control the hazard.

- **2.4.1 Planning and Procedures**

It is critical for management and the project team to understand the hazards and risks of the project, systematically considering and planning for health, safety and environmental control from the very early phases of the planning and design cycle. Specific to underbalanced and managed pressure drilling, primary areas of focus in the planning and design phases include hazard identification studies (HAZID), hazard and operability studies (HAZOP), development of operational procedures, site-specific safety documents, training and environmental impact studies. These focus areas are all related to the hazard identification process and are detailed in Figure 4.

- **2.4.2 Implementation**

An HSE Implementation Plan should be an integral part of the UBO or MPD project team's overall Project Implementation Plan. UBO and MPD operations should be conducted in accordance with approved procedures and the step-by-step drilling program prepared in the pre-execution planning phase or earlier, but flexible enough to allow for amendment using a formal Management of Change process. It should include pre-agreed Key Performance Indicators (KPI's) and performance monitoring. For example:

Health, Safety and Environment

Zero Total Recordable Incidents.

Zero Spills.

Minimal Flaring. REF: Environmental Impact Assessment.

Effective use of a safety observation/behaviour modification program. *Unsafe acts and practices discussed, reported and appropriate action taken.*

Technical Success

Drill to top reservoir TD within pre-defined tolerances.

Pressure integrity of all casing strings.

Cement program fulfilled: (to be verified with returns or logging).

Drill to sub-horizontal TD within pre-defined tolerances.

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Time and cost

Deliver within time and cost budget – *Approved Authorisation For Expenditure (AFE)*.

Organisation Effectiveness

- Deliver a plan that fulfils the approved Terms of Reference.
- Deliver required documentation and approvals with no operational delays.
- Fulfil the training requirements per the plan.

HSE performance can be optimised through a structured systematic planning process that incorporates the following:

- Comprehensive operational pre-planning incorporating HSE measures to manage identified hazards.
- Verification of equipment safety standards before operation start-up.
- Verifying that an effective HSE Management System is in place before start-up.
- HSE management training program for senior line management (OPCO and contractor) and direct supervisors. This training would include such topics as Job Hazard Analysis, Unsafe Act Auditing (UAA), unsafe behaviour and unsafe conditions observation, waste management and an understanding of the factors which affect behaviour.
- Detailed documented HSE and contingency planning prior to operational start-up.
- Regular combined Company and Contractor management team audits and inspections according to a planned schedule and focusing on HSE management.

Those project teams especially in the offshore sector, who have successfully implemented UBO & MPD from both an HSE and operational view, have verified this approach. The UBO or MPD Project Manager should review the plan, authorise it and check its implementation periodically. The plan should set out the UBO/MPD Project HSE objectives and the methods by which it will achieve them, lay down a time scale for implementation, identify action parties and establish a review process, both to monitor implementation and to modify the plan according to needs. It is not a static plan and is typically developed from:

- Requirements carried over from previous UBO/MPD projects
- Learning from other UBO/MPD projects both conducted internally and externally
- Audit and inspection findings
- Incident/accident findings
- New corporate initiatives
- HSE suggestions from the workforce
- Management review action items
- Information available from trade, industry and regulatory bodies

Performance Monitoring and Review

Performance monitoring and review is a key element of any plan since it is the part that facilitates enhancement by highlighting areas for improvement. HSE performance can be monitored and assessed against the criteria considered below but should include both proactive (measures taken to prevent accidents and incidents) and reactive which are measures of actual performance against targets.

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Occupational health

Measuring performance in relation to regional occupational health requirements and against company and industry standards. At a minimum, these must meet regulatory requirements and should ensure prevention of adverse health effects due to working conditions.

Safety

Generally accepted safety performance measurements are:

- Injury statistics
- Incident reports
- Risk assessment matrix (can also be used as an incident potential matrix)
- Unsafe act auditing
- Unsafe behaviour and unsafe conditions observation and reporting
- Feedback from drills, exercises, audits and inspections

Environment

A waste management program should be part of the UBO/MPD Project HSE Plan and be aimed at achieving short- and long-term reductions in the volume and toxicity of waste generated. For example:

- Substitution of chemical products, e.g. using water-based mud instead of oil-based mud
- Shipping of produced reservoir fluids such as gas (pipeline injection if possible), oil and condensates etc. to a facility
- Recycling of the waste stream

One final point on monitoring and review is related to management HSE inspections. These are very important in that they are not only a visible show of management support of the HSE plan but a window of opportunity for management to gain a first hand look at what is working and what is not, and to feed this information back to the people actively conducting the operation. However, to be effective and get the most out of the effort put into inspections in general and management inspections in particular, it is essential that a focused, structured and systematic approach be taken, comprised of the following key elements:

- Planning
- Execution
- Feedback and close out.

The HSE Implementation plan should also define the responsibility and authority for initiating investigation and corrective action in the event of non-compliance with specified requirements relating to the overall HSE Management System of the company. It is only when non-conformances are investigated to find the root cause that the right corrective action will be taken and closed out.

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To summarise, performance indicators must be measurable, monitored and the results recorded to demonstrate the extent of compliance with the plan. This can be accomplished by the use of suitable indices that will:

- Provide a consistent and reliable method for collecting and communicating data on incidents
- Show by comparison the effectiveness of the UBO/MPD project HSE management plan, both within the Operating Company (OPCO) and with other companies
- Enable an assessment of a contractor's HSE performance relative to industry standards
- Indicate whether it is a well-managed operation, or events are driving management of the operation.

Since UBO/MPD HSE planning is the central theme of this document, HSE issues related to planning procedures and implementation are further discussed within a project management framework in Section 3.

2.5. Audit

The UBO/MPD Project Team should maintain procedures for audits to be carried out, as a normal part of business control, to determine whether or not elements and activities of the HSE Management System conform to plan, and are implemented effectively. Competent people should conduct these audits in accordance with an agreed schedule, and an established protocol and procedure. The audit programme should be consistent with the complexity and duration of the project.

Audits may result in corrective actions and areas for improvement. Any substantial non-compliance should be reported to senior management. The company should develop and update a corrective action and improvements plan with the aim, where possible and practicable, of continuous improvement in HSE performance.

2.6. Management Review

The UBO/MPD Project senior management should, at appropriate intervals, review the HSE Management System in general, its performance and results, to ensure continuing suitability and effectiveness and where appropriate, implement improvements and corrective actions. Such a management review should include an overall assessment of the HSE Management System including the setting of strategic objectives consistent with industry, societal, legal and regulatory developments.

3. UBO/MPD Planning and Implementation

Underbalanced or managed pressure drilling operations whether with jointed pipe (JP) or with coiled tubing (CT) are not new technologies. Many companies have conducted land based UBO operations from about 1987. Wells have been drilled underbalanced (primarily on land) using both jointed pipe and coiled tubing. Further, companies have been drilling underbalanced or using managed pressure techniques in the offshore environment since 1997, employing jointed pipe. Many safety-related studies and research projects relative to UBO/MPD have been conducted. The depth of investigation and the quality of work present in these studies and reports, indicate that safe and cost effective management of UBO or MPD in high-pressure oil/gas reservoirs, whether onshore or offshore is possible.

More equipment, more people and significantly different operations are involved in the UBO/MPD operations, which translates into potentially higher risk. However, with the proper planning, hazard assessment and risk mitigation, a UBO or MPD operation can be a safe and profitable activity for both the operator and service companies involved.

Figure 4 illustrates how a UBO or MPD project can be broken into discrete phases with a defined structure and how some of the HSE deliverables fall into this structure. In a classical project management structure these phases may be defined as follows:

- Initial Well Design Phase (*Conceptual Design*)
- Detailed Well Design Phase (*Front End Engineering and Design*)
- UBO/MPD Planning Phase (*Detailed Design*)
- Implementation Phase (*Construction*)
- Pre-execution Phase Onsite (*Commissioning*)
- Execution Phase (*Start-up*)
- Project Completion (*Rig down and clear location*)
- Document close out and learning

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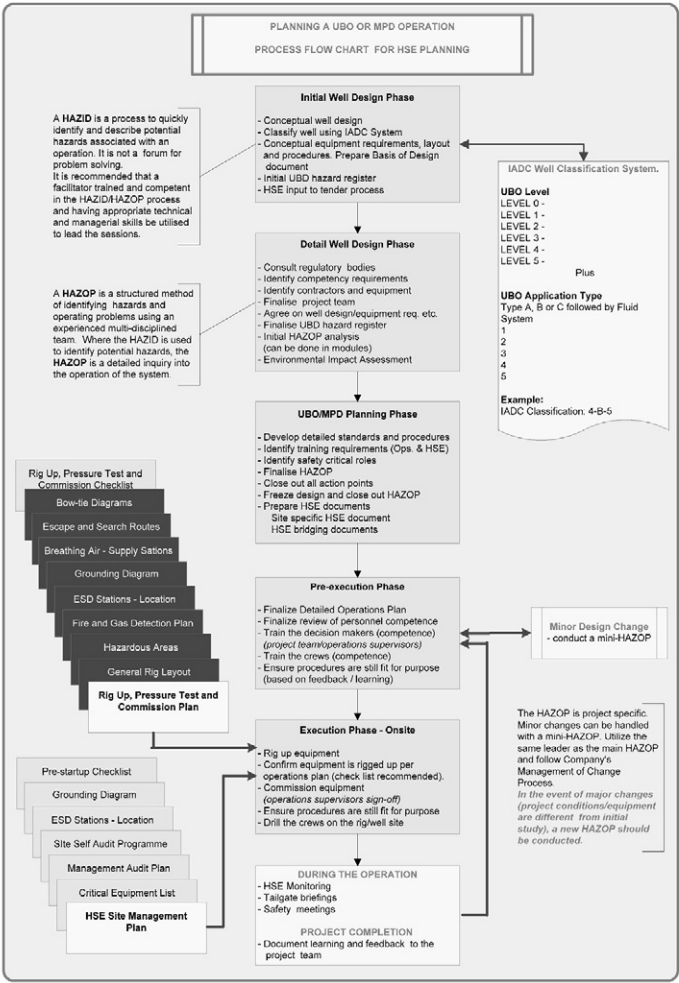


Figure 4 - Process Flow Chart for HSE planning

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3.1 Initial Well Design Phase

HSE planning begins with the conceptual well design. Various design options will be investigated, discussed and some will be discarded. A number of different options may be considered at this stage of the project. However, the selected option will usually be driven by a desire to minimize cost, minimize environmental impact and maximize deliverability from the reservoir (if applicable).

The initial task is to classify the well(s) and thereby determine the scope of the project, equipment and personnel needs from which the plan can be developed.

To assist with the categorisation of all wells drilled with UBO/MPD techniques, the IADC has adopted a classification system that combines the level of complexity/hazard and the UBO/MPD application type.

- 3.1.1 IADC Well Classification System for Underbalanced Operations and Managed Pressure Drilling

The purpose of the IADC Well Classification System is to describe the overall risk, application category and fluid system used in underbalanced operations (UBO) and managed pressure (MPD) drilling. Wells are classified according to:-

Risk Level (0 – 5)
Application Category (A, B or C)
Fluid System (1 – 5)

This classification system provides a framework for defining minimum equipment requirements, specialized procedures and safety management practices. For further information refer to the IADC website and other related documents.

- 3.1.2 Risk Level

Risk increases with operational complexity and potential well productivity. The examples provided here are for guidance only.

LEVEL 0 – Performance enhancement only; no hydrocarbon containing zones

Air drilling for rate of penetration (ROP) enhancement

LEVEL 1 – Well incapable of natural flow to surface. Well is inherently stable and is a low level risk from a control point of view.

Sub-normally pressured oil wells

LEVEL 2 – Well is capable of natural flow to surface but can be controlled using conventional well kill methods. Catastrophic equipment failure may have limited consequences.

Abnormally pressured water zones

Low flow oil or gas wells

Depleted gas wells

LEVEL 3 – Geothermal and non-hydrocarbon bearing formations. Maximum anticipated shut-in pressure (MASP) is less than the UBO/MPD equipment pressure rating.

Includes geothermal wells with H₂S present

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LEVEL 4 – Hydrocarbon bearing formation, maximum anticipated shut-in pressure is less than UBO/MPD equipment operating pressure rating. Catastrophic equipment failure will likely have immediate serious consequences.

- High pressure and/or high flow potential reservoir
- Sour oil and gas environments
- Offshore environments
- Simultaneous drilling and production operations

LEVEL 5 – Maximum anticipated surface pressure exceeds UBO/MPD equipment operations pressure rating. Catastrophic equipment failure will likely have immediate serious consequences.

- Any well where MASP is greater than UBO/MPD equipment pressure rating

- 3.1.3 Application Category

Category A – Managed Pressure Drilling (MPD) – Drilling with returns to surface using equivalent mud weight that is maintained at or above the open-hole pore pressure.

Category B – Underbalanced Operations (UBO) – Performing operations with returns to surface using an equivalent mud weight that is maintained below the open-hole pore pressure.

Category C – Mud Cap Drilling – Drilling with a variable length annular fluid column which is maintained above a formation that is taking injected fluid and drilled cuttings without returns to surface.

- 3.1.4 Fluid Systems

1. Gas – gas as the fluid medium. No liquid added intentionally
2. Mist – fluid medium with liquid entrained in a continuous gaseous phase. Typical mist systems have less than 2.5% liquid content
3. Foam – two-phase fluid medium with a continuous liquid phase generated from the addition of liquid, surfactant and gas. Typical foams range from 55% to 97.5% gas.
4. Gasified Liquid – fluid medium with a gas entrained in a liquid phase
5. Liquid – fluid medium with a single liquid phase

- 3.1.5 Example

A well is being drilled from 10,000 feet to 12,000 feet utilizing managed pressure drilling techniques. The pore pressure of the formation is 14.5 psig and the fracture gradient is 16.5 ppg. The design is predicated on using a 13.0 ppg fluid and maintaining a balanced system with surface pressure. The rotating control device (RCD) and emergency shut down (ESD) systems are rated at 5000 psi.

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From the above information:

MASP is the lesser of BHP minus gas to surface or frac at shoe minus gas to surface

$$\text{MASP}_{\text{BHP}} = 12000 \times 0.052 \times (14.5 - 2) = 7800$$

$$\text{MASP}_{\text{fr}} = 10000 \times 0.052 \times (16.5 - 2) = 7540$$

As the maximum anticipated surface pressure exceeds the UBO/MPD equipment rating, the classification for the well would be:

Level 5, Category A, Fluid System 5 or 5A5

If the company has been drilling wells before using the same technique, there may be no need to change their drilling practices and procedures. If on the other hand, the company has never conducted UBO or MPD operations, they will likely have to consult other specialist companies or contractors for equipment requirements, any rig modifications required and the lease construction needed including the impact the operation will have on the crews unfamiliar with the process.

Having classified the type of well to be drilled, the design team will then develop conceptual equipment requirements, layout diagrams and conceptual procedures. A key ingredient of successful project management, or for that matter HSE management, is documentation and document control. The basis of design document, the hazard register, and the HSE input to the Tender Process are key documents to be delivered in this phase of the project. The basis of design document will be referenced throughout the project. It may be updated and revised as appropriate as the project develops. It is critical that only an up-to-date version be used for obvious reasons. The same applies for all documents, hence the need for good document control in the project.

If other companies or experts are consulted for advice, the company may increase awareness of the HSE and local regulatory requirements for the job at hand. Once again, the level of complexity of the well to be drilled and the UBO/MPD experience of the company will dictate what else needs to be in place for the job to be done safely. In the example of air drilling, the primary environmental impact will be from noise and dust and must be addressed in the drilling plan. If however, the company has limited experience with this type of operation, then the following sections may be relevant and will provide guidance on the HSE issues and requirements in the various phases of the project.

- 3.1.6 UBO/MPD Hazard Identification

Most companies will have a generic hazard register related to the activities of the company, if not, one should be generated listing the hazards and risks associated with their activities including measures taken to eliminate or mitigate risk. Some of the hazards related to UBO/MPD such as H₂S, confined space entry, flaring etc. are common to other activities and should already be identified for drilling and well testing in the Operating Company's Hazard Register. However, new hazards are introduced in a UBO/MPD operation. These generally relate to:

- I. The change in barrier philosophy whereby the primary barrier, the mud column, is replaced with a mechanical barrier, the rotating control device (RCD), resulting in drilling with pressure at surface.
- II. The use of drilling fluids such as condensate, low flash point crude etc.
- III. Flowing while drilling & other simultaneous operations.
- IV. High pressure lines at surface (injection & flow lines) containing energised fluids.
- V. ... and more depending on the nature of the operation.

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The HAZID study is a process used to quickly identify and describe potential hazards associated with an operation. The HAZID study conducted in this phase is sometimes referred to as a coarse or an initial HAZID. The results are entered in the UBO/MPD hazard register. The process may be repeated in the next phase of the project once all service contractors for the project are selected and the equipment design is better defined. It is important that an experienced facilitator competent in the application and use of the technique be assigned tasks of team leader. A team with the right mix of design and operational expertise in the various processes/sections especially in the facility section is very important for optimum outcome of the exercise. Large numbers do not add value; knowledge and willingness to actively participate and share knowledge does. It should also be remembered that this is a hazard identification exercise, not one for problem solving. Resolution of action items arising should be done outside the HAZID sessions.

In addition, conceptual well-design schematics, conceptual layout drawings showing the UBO equipment, the rig and equipment, the hazardous areas/zones and the escape routes, and conceptual procedures are required to conduct a proper HAZID.

The final HSE deliverable from this phase will likely be HSE input to Tender Process. Most operators will likely have a standard format for HSE in their contract documents. This usually requires additional HSE input for a UBO or MPD project. The structure for management of HSE during the project or contract period should be made clear, as should the expectations of the contractor regarding documentation, HSE input to HAZOP studies, HSE monitoring and auditing etc.

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3.2 Detailed Well Design Phase

Most of the activities in this phase of the project will require HSE input. These activities include, but are not limited to:

Consultation and briefing of local authorities.

In most oil and gas operating areas, governmental agencies regulate drilling operations and HSE regulations are becoming more stringent. It is prudent to consult relevant local authorities early in the project; plans should be discussed (especially if the technique has never been applied before in their jurisdiction) and feedback obtained from them if appropriate. This may provide HSE direction for the team by identifying potential HSE concerns and allow these to be addressed by the team in the forward plan.

Simultaneous or concurrent operations review.

Simultaneous drilling operation and hydrocarbon production from the same well is another one of the major hazards introduced in UBO/MPD and will require review of the interface issues for effective management.

Environmental and health reviews, dropped objects and other hazard mitigating studies as appropriate.

The environmental impact review needs to be done early in the design phase to avoid unexpected problems later in the project that might delay or even stop the project.

HSE influence in contract award process by the Client

Competency of personnel will be a critical success factor for the project. Contractors should provide as part of the tender submission to the Client, a portfolio of people with the required competency to meet expectations. Equipment proposed will likely be evaluated from both an HSE point of view and the basis of design as it relates to the business case objectives for the project. Therefore, tender proposals should reflect compatibility with these requirements.

- 3.2.1 HSE Considerations in Design

Once the contracts are awarded, the composition of the project team should be finalized. It is important that one of the design team members have an HSE role. The team should then agree on and finalize the well design and equipment requirements for the job. Some HSE issues to consider are:

Management of HSE interface issues between the operator, drilling and UBO/MPD contractors. There needs to be total commitment and support from all parties involved.

Drilling fluid assessment. This is generally one of the major hazards identified in the UBO/MPD Hazard Register. Discussion and clear justification regarding the use of any hazardous drilling medium, and agreement on how the associated hazardous substances will be used, stored and handled, is essential.

UBO/MPD system design, e.g. injection systems.

Drill string design and BHA selection, specification and analysis of real-time data acquisition systems.

Rig interfacing issues.

Well control principles and practices.

UBO/MPD operational practices and procedures.

Well site supervision; both technical and operational.

Underbalanced or managed pressure completions design.

Barrier philosophy. This is critical to UBO/MPD operations and one of the major new hazard topics usually raised for discussion on UBO/MPD projects.

UBO/MPD surface system equipment selection, suitability and optimisation.

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Engineering management of change process to be agreed.

The importance of document control should be re-emphasized.

As stated it is important that there is HSE input and integration with the engineering work.

- 3.2.2 HAZID and HAZOP Studies

At this stage the team will be ready to conduct detailed HAZID and initial HAZOP studies. It is essential to understand that these are two different techniques, investigating two distinct areas of the operation. To prepare for the detailed HAZID and HAZOP review the following diagrams are required:

- General Rig Layout (this and the following diagrams are reviewed during HAZID)
- Hazardous Areas
- ESD Stations - Location
- Fire and Gas - Detection, Alarms and Protection
- Grounding Layout
- Breathing Air Supply (if appropriate)
- Escape and Search Routes
- "Bow-tie" Diagrams for Major Hazards
- Process and Instrumentation Diagram (reviewed during HAZOP)

Some of these may be combined on one diagram but the importance of the above diagrams cannot be overstated. They are required not only for the HAZID and HAZOP reviews but also for the rig-up process on-site during the execution phase. They should be included in the list of deliverables in the tender and contract award documents. HAZID and HAZOP studies have been used extensively on many UBO and MPD projects. Previous HAZID/HAZOP studies may include the following, specifically aimed at the design and operation of:

- The surface separation system;
- The nitrogen generation/injection system;
- The snubbing system;
- Completion equipment including down-hole isolation;
- The drill string including BHA and drill-pipe isolation;
- The complete UBO/MPD system, including interfaces and logistics.

There will be a tendency to assume that since others have done these studies, there is no requirement to repeat the process. This is simply not so. Each project must be evaluated on its own merit as hazards, risks, locations, environmental conditions and equipment requirements vary. With time, a database of identified hazards and risk mitigation actions may be an outcome of these studies, but all members of the team should be cautious and not assume that a HAZID or a HAZOP is not required for any future activities. The availability of a database of information simply provides a means to speed up the risk evaluation process, as appropriate previous work can be referenced to close out action items.

The UBO/MPD project team should recognise that contractors providing the services and equipment associated with UBO/MPD may not be familiar with HAZID and HAZOP techniques. Therefore, responsibility for these studies resides with the Operating Company (OPCO) rather than the contractor to ensure that the quality of the study is consistent with OPCO standards. Properly planned and conducted HAZID/HAZOP sessions are also effective tools for team building and personnel commitment to the safety culture necessary for a successful UBO or MPD operation. Therefore, it is important that operations personnel are involved in the process. When the drillers and assistant drillers are invited to participate, they provide excellent feedback on hazards specific to their rig and have previously been instrumental in reducing non-productive time on many UBO/MPD projects. They also provide advice to their crews on the process, which can also effectively reduce the anxiety of crews new to UBO/MPD operations.

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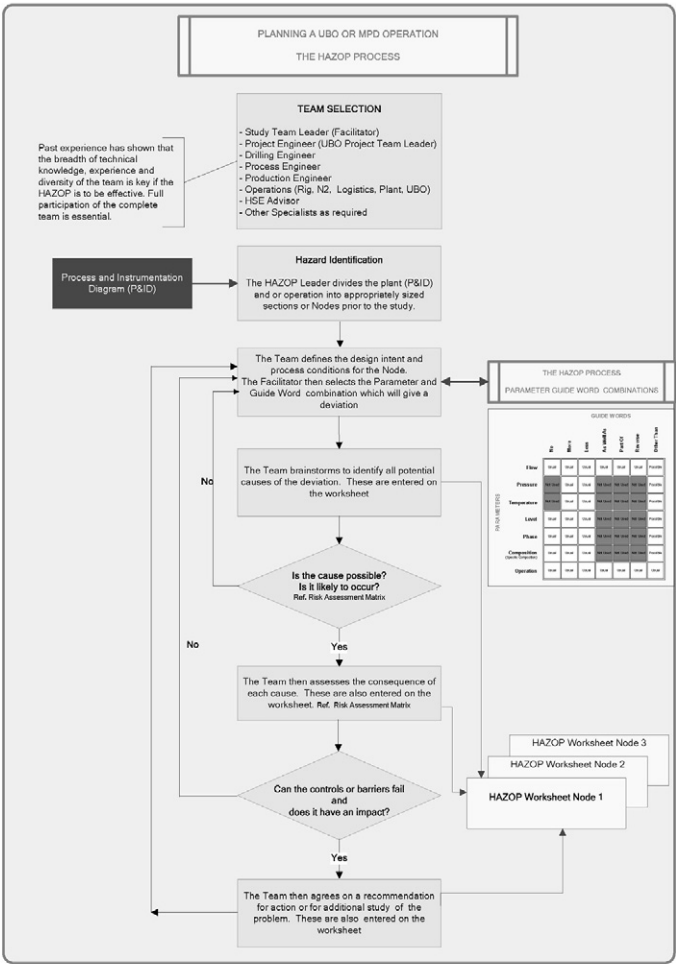


Figure 6 - HAZOP Process

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- 3.2.3 Environmental Impact of UBO/MPD

One of the implications of underbalanced drilling is the production of hydrocarbons. These can be stored (liquids), flared (gas), or transported to a production facility via a pipeline. Whatever method is chosen for handling the produced hydrocarbons, an impact on the environment cannot be avoided. Storing liquids in vented tanks may release aromatics such as benzene into the environment. Flaring is undesirable and often not allowed in today's operating environment but eliminating flaring does not eliminate environmental impact, it moves it elsewhere.

The boats and trucks used to transport hydrocarbons to a facility add to greenhouse gas emissions; as do the compressors required to put gas into a pipeline system. In addition, compressors affect the workers by additional exposure to noise and vibration. The project team should strive to minimise the total environmental impact from the UBO or MPD operation. There will be a strong requirement to communicate to the stakeholders ensuring they clearly understand that a UBO or MPD operation may require some flaring as the most environmentally responsible option. This by-product of underbalanced or managed pressure drilling may conflict with production permits in some operating areas that restrict flaring to emergencies only. A frank and open discussion with the local oil and gas authorities will indicate whether flaring is a problem and the effort that will be needed to address these concerns.

The UBO/MPD project team must evaluate the HSE impact of flaring and the feasibility of using compressors to put gas into the production lines (if available). The use of "green burners" to reduce the impact of night flaring on the local community and in restricted areas should also be evaluated. At the end of it all, there may be a need to justify UBO and the requirement to flare to management and the stakeholders. One approach is to do a comparison of the environmental impact of drilling a conventional well, and having to stimulate (frac) to make the well commercial vs. a UBO/MPD operation. If there are no pipelines on the location, the environmental impact due to flaring may be slightly higher for the UBO/MPD option, but the overall environmental impact and HSE risk, may be less with UBO/MPD due to reduced exposure.

However, although this approach is currently acceptable, calculating and comparing the total energy consumption and the equivalent greenhouse gas emissions of the conventional and the UBO/MPD approach, may be required in future as part of the business case for UBO/MPD in the field development plan.

3.3 UBO/MPD Planning Phase

Many of the activities in the UBO/MPD planning phase also require HSE input. These include development of procedures, identification of training requirements and safety critical roles. In addition the system design should be "frozen" (i.e. no further alterations allowed except via the Management of Change Procedure) and the HAZOP finalized by closing out all action points. Finally, HSE documents will have to be prepared.

- 3.3.1 Operational Procedures

Quality operational procedures are a key requirement to conducting a safe, efficient UBO or MPD operation. The need for specific procedures will be a likely outcome of the HAZID process. They should be precise, yet easy to use and if possible should be written in the language of the user. Having detailed operating procedures allows individual actions and sequences to be reviewed (usually during the HAZOP) prior to the execution phase. In addition, these procedures are required for training and competence development of the crews. This is especially important in an UBO or MPD operation, which involves integrated services and service providers, and where there is an interdependent relationship for a safe and efficient operation. Figure 7 is an example of the table of contents for a UBO/MPD

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Procedures Manual for a Project. To be managed effectively, the agreed Engineering Management of Change process must be adhered to in order to change an approved operating procedure.

TABLE OF CONTENTS	
SECTION A – PLANNED EVENTS.....	
1.	SURFACE EQUIPMENT.....
1.1	Mobilisation.....
1.2	Hoisting.....
1.3	Demobilisation.....
1.4	Commissioning.....
2.	DRILLING ASSEMBLY – DEPLOYMENT AND TRIPPING IN.....
3.	DRILLING UNDERBALANCED OR MANAGED PRESSURE.....
3.1	Drilling Ahead.....
3.2	Drilling – Making Connections.....
3.3	Drilling – Displacing Micro Annulus to Nitrogen.....
4.	PLANNED SHUT DOWN OF DRILLING OPERATIONS.....
5.	DRILLING ASSEMBLY – TRIPPING OUT AND RETRIEVING.....
6.	LINER RUNNING PROCEDURE.....
7.	EQUIPMENT DE-COMMISSIONING AND RIGGING OUT.....
8.	VISITORS TO THE RIG.....
SECTION B – UNPLANNED EVENTS.....	
1.	DRILL STRING.....
1.1	Drill String Failure.....
2.	FISHING.....
3.	CLOSURE OF THE ESD VALVE.....
4.	WELL KILLING.....
4.1	Well Killing – Failure above the Swab Valve.....
5.	EMERGENCY SHUT IN OF WELL WITH BOP'S.....
6.	FIRE OR ABANDON RIG ALARM.....
7.	RIG POWER UNIT (Rig Set) FAILURE.....
8.	RIG PUMP FAILURE.....
GLOSSARY OF TERMS.....	
SECTION C – DECISION TREES.....	
1.	GLOSSARY OF SHAPES IN DECISION TREES.....
2.	TRIPPING.....
2.1	Determining Friction Factor in Rotating Control Devices.....
2.1	Downhole Swab Valve Opening.....
2.3	Object Dropped on Closed Downhole Swab Valve.....
2.4	Hole Pulls Tight.....
3.	DRILLING.....
3.1	Stalled Mud Motor.....
3.2	Borehole Instability.....
3.3	Formation of cuttings beds.....
3.4	Drill String Failure.....
3.5	Rig Pump Failure.....
4.	EMERGENCY RESPONSE.....
4.1	ESD System Failure.....
4.2	Driller Initiated Emergency Shut-In.....
4.3	Emergency Well Kill.....
4.4	Fire/Abandon Ship alarm.....
4.5	Generator Set (Power) Failure.....

Figure 7 – Example Table of Contents for a Procedures Manual

UB & MPD Operations – HSE Planning Guidelines

- 3.3.2 Training and Competence Requirements

Training of personnel on a rig site is critical to a safe operation. In a UBO or MPD operation, training becomes even more important because of the number of interdependent services and personnel involved. Failure to recognise the impact of their actions or decisions on the overall process can have potentially serious consequences.

Regardless of whether the training takes place offsite, on-site, or both, training for a UBO or MPD operation may have a substantial associated cost. The training programme can be area, regional and/or well-specific, and to minimise costs must be fit for purpose; training is not optional. Due diligence requires that only trained, competent personnel are allowed to work on a UBO/MPD site and/or personnel in the process of becoming competent are properly supervised by competent staff.

To ensure placement of only competent personnel in safety critical roles, the industry is slowly moving towards competence-based training. Although there are variations in the approach to competency-based training throughout the world, the objective is the development of a competent workforce. This requires a system that sets standards for what competencies are required for a task or role, how to train and develop competent staff to these standards, and how to assess competence on an ongoing basis. Companies requiring further information on the subject should consult experts in the field of competency-based systems.

In line with this objective, IADC has approved the UBO Rig Pass Orientation document (focused on the general UBO safety training needs of all personnel) and Underbalanced WellCAP Curriculum, which emphasizes flow control with different equipment and procedures from conventional drilling operations. Underbalanced WellCAP is aimed at training the well-site supervisors and the intent is to ensure that conventional well control thinking and procedures do not compromise UBO well objectives. Information on accredited schools can be obtained from the IADC. This training is also applicable to MPD.

In addition to normal requirements for their operational roles, personnel considered to be in safety critical roles on a UBO or MPD operation will require additional competencies.

Even if a company has been drilling underbalanced or managed pressure wells and is confident their people are competent at their jobs based on work experience, the following section may still have relevance simply as a process check or to improve existing training profiles for staff. Remember that personnel in safety-critical roles may have specific safety training needs.

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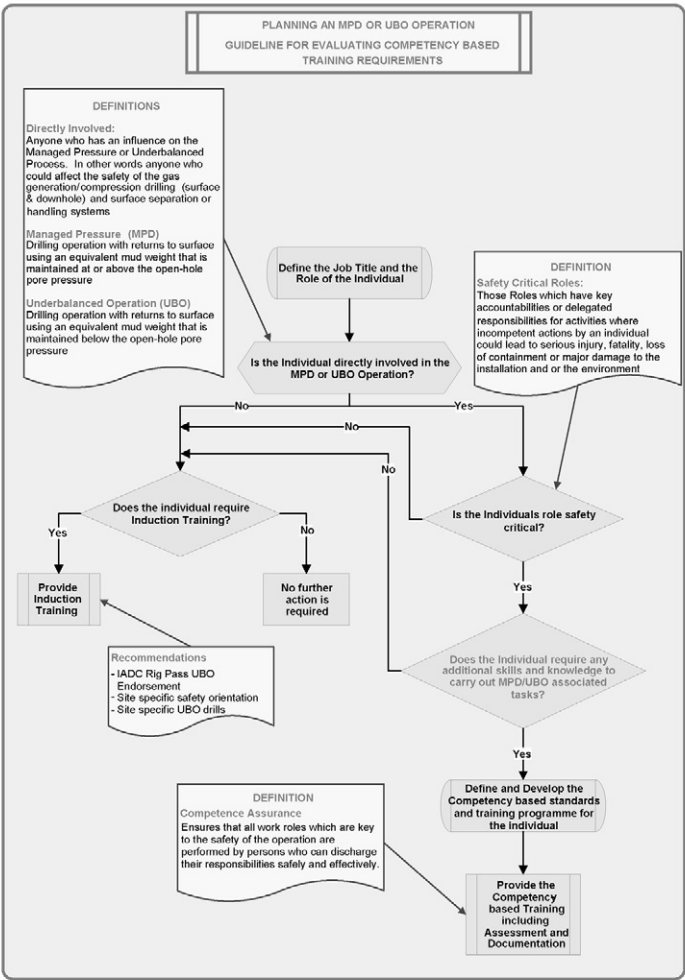


Figure 8 - Guidelines for Evaluating Competency Based Training

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Figure 8 entitled "Guidelines for Evaluating Competency Based Training" will allow the UBO/MPD project engineer to evaluate if additional competency training is required.

This illustrates one format for documenting the UBO/MPD related training requirements (HSE and operational). It is meant as an example and as such, it is not complete, nor is it a definitive document regarding which roles are considered safety critical. In some operating areas, the roles of individuals may vary based on their level of experience and they may be required to fulfill a safety critical role regardless of title. It is recommended that the safety critical roles for any new UBO/MPD operation or project be reviewed using this guideline as part of the planning cycle.

Once the safety critical roles are established and the requirement for additional training is identified, begin addressing the specific areas in the individual training plan. Figure 9 identifies some of the functional modules required in the training program with the communications module as an example. Once again this list may not be all-inclusive, but is a good starting point.

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Role	Safety Critical (Y/N)	Induction Training Required (Y/N)	Competency Based Training Required (Y/N)	Justification
Derrickman				
Driller	Y	N	Y	The Driller will probably experience the greatest degree of change from his normal practices in a Managed Pressure or Underbalanced drilling operation. Consequently it is likely that in this case there may be different levels of competency to be achieved, e.g. able to work without direct supervision or able to work but under direct supervision.
Barge Engineer				
Catering or Camp Crews				
Crane Driver	Y	N	Y	Handles and positions equipment which can have a significant impact on the process
Assistant Derrickman				
Assistant Driller				SEE DRILLER
Directional/MWD Crews	N	Y	N	Role not considered to be Safety Critical
Drilling Supervisor (Day/Night)				
Engineering/Construction Crews				
Fixed Installation or Production Operations Crews				
Logistics Crews				
Mechanics/Welders				
Medic				
Motorman				
Mud Engineer				Role not considered to be Safety Critical
Nitrogen Crews				
Non-Operational Visitors				
OIM Oil Production Facility				
OIM Rig Vessel				
Onsite Safety Supervisors				
Project Manager				
Radio Operator				
Rig Managers (Contract Company)				
Rig specific Senior Well Engineer				
Rotating Control Device (RCD) Technician				
Roughnecks				
Roustabouts				
Scaffold Crews				
Snubbing Crews				
Surface Separation Crews				
Toolpusher (Day/Night)				
Truckers (hydrocarbon hauliers)				
UBO/MPD Supervisor (Day/Night)				
Well Service Crews				

Table 2 – Example UBO & MPD related training requirements

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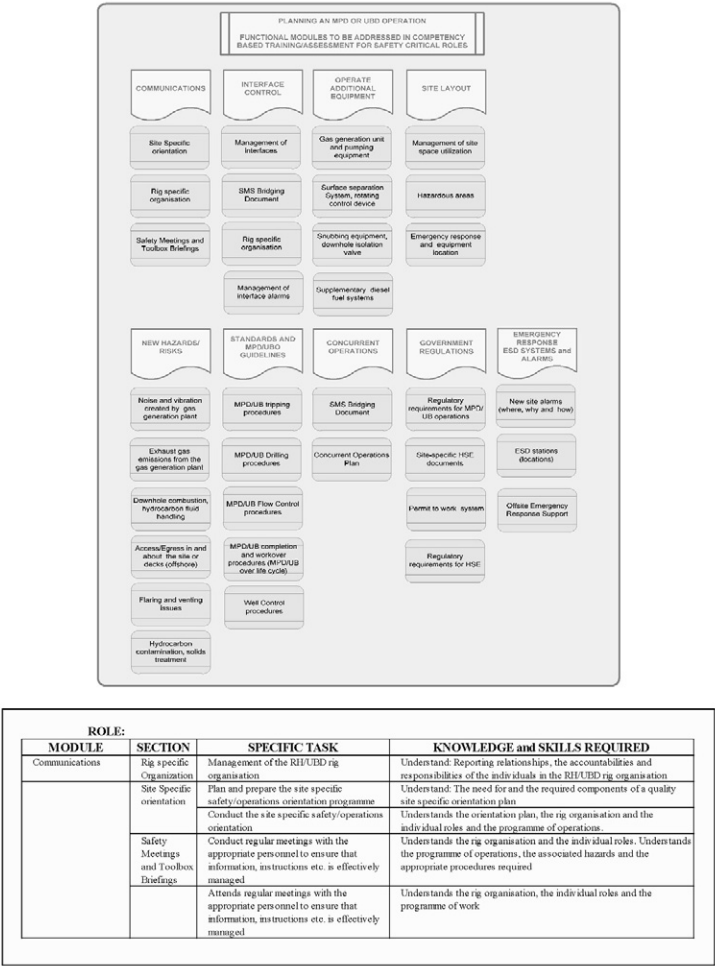


Figure 9 - Generic Functional Training Modules and Communication example

UB & MPD Operations – HSE Planning Guidelines

3.3.3 Safety Management Systems Support Documents

To improve the safety of UBO or MPD projects, participants (operator, drilling contractor service contractors etc.) should all be familiar with the Safety Management System bridging document, Site Specific Safety Case and Rig Safety Case.

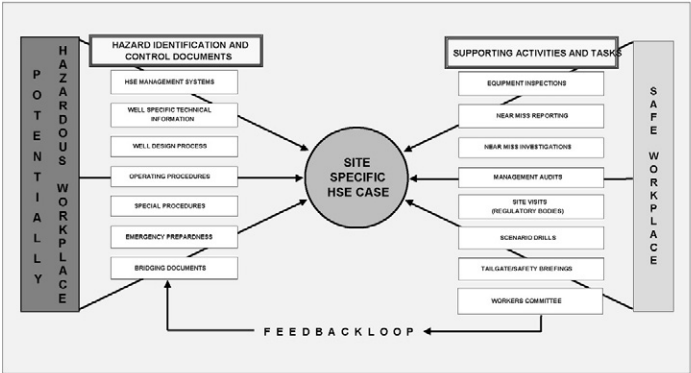


Figure 10 – Graphical illustration of Linking Function of Site Specific HSE Case Document

Although Figure 10 may appear to be a “bow-tie” diagram, it is intended to graphically demonstrate how a site-specific HSE Case links together effective HSE Management Systems, equipment design and procedures with specific actions at a potentially hazardous location to make it a safer workplace. Figure 11 illustrates the relationship between the site safety case and other safety and operational documents.

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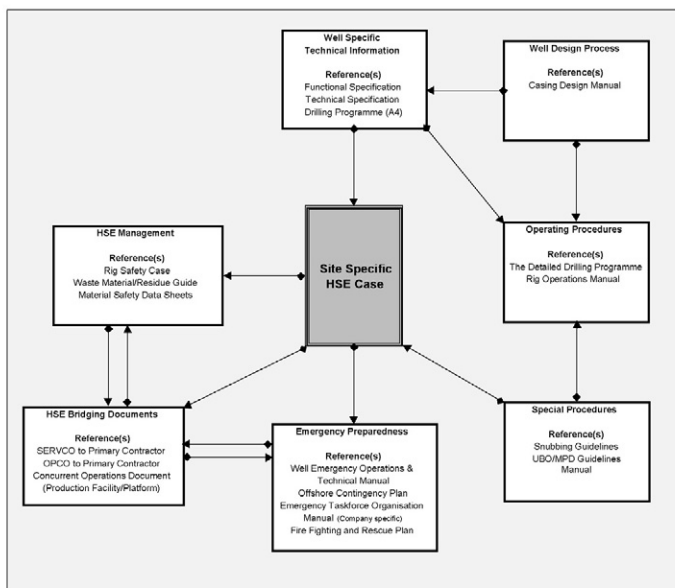


Figure 11 – Relationship between the site safety case and other project documents

3.4 Pre-execution Phase

Most of the activities in this phase of the project have a direct impact on HSE performance. The detailed operations plan (drilling program) will be prepared and HSE function will have input in the plan. In addition, personnel will be trained and other HSE related documents prepared.

- 3.4.1 Training

IADC recommends that all on site operations personnel have UBO Rig Pass Orientation training. In addition, all on-site operations UBO/MPD Supervisors including drillers and assistant drillers must have valid WellCAP UBO well-control certification. Each company involved in the project will have a training programme for developing competency of staff. To reduce training cost it is important that redundant training requirements be reviewed and eliminated where possible. An auditable competency-based training system helps in this regard.

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- 3.4.2 HSE Site Management Plan

Some of the issues that need to be addressed in the plan include but are not limited to:

Identification, inspection and preventative maintenance of UBO/MPD safety-critical equipment.
Pre-start-up HSE audit (1st well on project), pre-start-up inspections on subsequent wells, and a site and management audit programme consistent with the scope and duration of the project.

3.5 Execution Phase

This phase begins with the arrival of the UBO or MPD equipment on site. Once the equipment is rigged up, Supervisors need to execute the HSE site management plan and ensure the equipment is rigged up in accordance with the Process and Instrumentation Diagram (P&ID) and operations plan (check list recommended). The system will be pressure tested and commissioned consistent with the plan (operations supervisors sign-off). Procedures must be reviewed to ensure they are still fit for purpose and the crews will be drilled on the critical procedures.

- 3.5.1 Learning and feedback

The monitoring and review process must address the meeting of targets documented in the UBO/MPD Project HSE Plan. It should also address successful close out of action items arising out of activities that produce recommendations, such as HSE meetings, inspections and incident investigations etc. Learning and feedback are critical components in the continuous improvement loop. In order to promote sharing of HSE related learning within the UBO/MPD industry, the following approach to incident reporting is recommended:

Whatever reporting format is used, if the class, process and component keywords in Table 3 are used properly and embedded in the report, a database of UBO/MPD related incidents can be created to facilitate the identification of potential problem areas and learning experience to be shared.

Figure 12 illustrates an example of a UBO or MPD incident report using the IADC Safety Alert format and demonstrating how the class, process and component keywords can be used in this format. Since this database already exists UBO/MPD information can be extracted once reports are submitted using the recommended keywords.

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DATE	IADC UBO CLASS (Code)	PROCESS (Keyword)	COMPONENT (Keyword)	DESCRIPTION (Summary)	KEY FINDING (Root cause)
Process Keywords			Component Keywords		
BAR (barrier)			RCD - rotating control device NRV - non return valves		
BOP (primary BOP equipment)			ANN- annular RAM - any ram VAL - any of the valves		
SNUB (snubbing related equipment)			JACK - snubbing jacks ANN- annular RAM - any ram VAL - any of the valves		
RIG (rig related equipment)			HOIST – any of the derrick/hoisting equipment PUMP - pump related equipment CIRC - circulating system equipment HAND - handling equipment ELEC - electrical equipment		
SURFACE (surface separation related equipment)			SEPAR - separation equipment SOLID - solids handling equipment CHOKE - choke manifold/valves FLARE - flare system SAMPLE - sample catcher		
GAS (gas generation/injection related equipment)			FEED - feed compressor MEMB - membrane unit BOOST - booster compressor PUMP - cryogenic nitrogen pumper		
DP (drill pipe)			BODY - pipe body TJ - tool joint BOX/PIN - threads		
BHA (bottom hole assembly components)			MWD - directional tool LWD - logging tool PWD - pressure tool NM - collars		
WH (wellhead components)			SPOOL - spools VALVE - valves		

Table 3 - Incident reporting (process and component keywords)

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IADC Safety Alert Submission

Please use this form to submit information for use in future IADC Safety Alerts. Attach separate sheets, diagrams or pictures if needed.

TOPIC? *General description of subject discussed.*

Include UBO/MPD Well Classification in accordance with IADC Guidelines

WHAT HAPPENED? *Please provide a brief description of the incident, hazard or situation.*

WHAT CAUSED IT? *List possible or known causes or dangers resulting from this situation.*

WHAT CAN/SHOULD BE DONE? *List actions or practices to prevent this situation.*

Please submit this information to IADC, P.O. Box 4287, Houston, TX USA 77210-4287, or fax to 1/713-292-1946.

Name of person submitting information _____

Title _____ Company _____

Address _____

City, State, Country _____

Phone Number _____ Fax Number _____ E-mail _____

My company hereby provides permission for IADC to share this information with its member companies, general industry, and the general public via posting on the IADC website with the understanding that individual persons or companies will not be identified.

Signature _____

Date _____

Figure 12 - Example incident report using the IADC Safety Alert Submission

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4. Summary

In summary, these Guidelines should be considered as a starting point for the Operating Company, the Drilling Contractor and the UBO/MPD Service Contractor in developing their UBO or MPD Safety Management programs and associated operational plans and procedures. Each Operator and the Service Contractors involved in the UBO/MPD project should review and apply the Guidelines according to its own policies and experience for the particular area and the appropriate risk level of the operation. The generic HSE Management System was used to convey the important aspects of Safety Management and how each component applies to HSE management within the UBO/MPD project. A Project Management framework was used to illustrate HSE planning in the various phases of the project.

In the national and local areas, where wells are being drilled there will be statutory requirements, rules and regulations that apply to the activities to be conducted on these wells. The industry also recognises certain Standards, Codes and Recommended Practises. In addition, the client may have their own HSE Management system, as will many of the contractors involved in the project. This document should be regarded as complementary to requirements, systems, standards and practices but not in any way supplanting them. Figure 13 illustrates the relationship of the Guidelines to them.

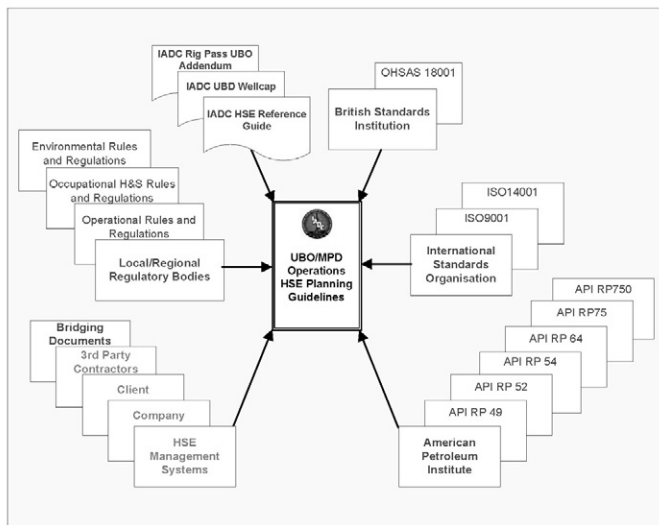


Figure 13 - Complementary relationship of the Guidelines

5. Appendix

5.1 References

IADC: HSE Reference Guide

API 16 RCD: Specification for Rotating Control Devices (RCD)

API RP49: Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide Third Edition

API RP52: Land Drilling Practices for Protection of the Environment Second Edition R(2000)

API RP54: Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations Third Edition

API RP64: Recommended Practices for Diverter Systems Equipment and Operations Second Edition

API RP75: Recommended Practices for Development of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities Second Edition

API RP750: Recommended Practices for Management of Process Hazards First Edition; Erratum - 1990 R(1995)

ISO 14001: Environmental Management Systems - Specification with Guidance for Use First Edition; CEN EN 1996

OHSAS 18001: Occupational Health and Safety Management Systems - Specification References

5.2 Glossary of Terms

Reference the IADC Glossary on the IADC-UBO WEB Site with the following link:

http://www.iadc.org/committees/underbalanced/completed_documents.html

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APPENDIX F

IADC UB and MPD Glossary

UBO & MPD GLOSSARY



Used with permission of the Underbalanced
Operations & Managed Pressure Drilling Committee
of the International Association of Drilling Contractors

A.

Abnormal Pressure - Reservoir pore fluid pressure that is not similar to normal saltwater gradient pressure. The term is usually associated with higher than normal pressure, increased complexity for the well designer and an increased risk of well control problems. Abnormal pressure gradients exceed a 10-ppg equivalent fluid density (0.52 psi per foot). Gradients below normal are called subnormal.

Absolute Pressure - pressure measured with respect to zero pressure; the sum of atmospheric pressure and gauge pressure.

Absolute Temperature - temperature measured with respect to absolute zero, in degrees Rankine or degrees Kelvin.

Absolute Viscosity - dynamic relationship between a force and the fluid motion.

Absolute Zero Temperature - temperature that prevents molecular motion.

Acceleration - rate of change in velocity.

Active data - continually updated data, based on latest operational data.

Actuators - part of a control system, which regulates speed, power, valve position, etc. to match a set point.

Adiabatic - process that is at constant temperature without loss or gain of heat.

Adiabatic Efficiency - ratio of theoretical temperature increase to actual temperature increase; a measure of the work done by a compressor that is not lost as heat.

Adapter Spool - connects blowout preventers of different sizes or pressure ratings to the casing head.

Adequately Ventilated Area - is an area having a natural or artificial ventilation system to prevent the accumulation of gases to an explosive level. API Recommends 12 air volume changes per hour or 1.5 CFM per square foot of floor area whichever is greater.

Adjustable Choke - A choke with a conical needle and seat vary the rate of flow. See also chokes

Aeration - injecting gases in varying amounts into a fluid..

Aftercooler - Heat exchanger used post compression to reduce gas temperatures.

Air Cutting - inadvertently incorporating and dispersing air (mechanically) into a drilling fluid system.

Anchor - Device used to secure items of equipment, important in the context of UBD where vibration is a factor or concern.

Affinity Laws - equations that correlate the relationship of head, speed, impeller diameter, flow, and efficiency for turbo machinery.

Ambient Temperature - temperature of the surroundings.

American Standard Code for Information Interchange. (ASCII) - A different byte represents each number, letter, symbol and punctuation mark. Replaced by Unicode.

ASME - American Society of Mechanical Engineers.

ANSI - American National Standards Institute.

Aniline Point - The aromatics content of a hydrocarbon mixture.

Annulus Friction Pressure (AFP) - Difference between bottomhole pressure and choke pressure due to friction; a function of flow rate, hole geometry, surface roughness, fluid properties.

API - American Petroleum Institute. .

API Gravity - arbitrary measurement of density adopted in 1921 by the American Petroleum Institute and the Bureau of Standards.

Apparent Power - combination of real and reactive power.

Apparent Viscosity - Slope of the shear stress versus velocity gradient for a fluid. For Newtonian fluids, the apparent viscosity equals the absolute viscosity.

Aromatics - Ring group chemical structure. Most common are benzene, toluene, and xylene.

B.

Back Pressure Valve - A flow control valve to provide backflow control when running or pulling a string.

Backup - Redundant equipment available to complete an operation in the event the primary equipment fails.

Balance - steady state of flow line or vessel has three critical characteristics: a) a single flow rate from node to node; (b) an even pack throughout the system; and (c) approximately equal volumes entering and leaving the line or vessel.

Ball Check Valve - A valve permitting flow in one direction only by lifting a spring-loaded ball off its seat. Valve opens when pressure differential acts in the desired flow direction. The valve seals by forcing the ball tightly against the seat when a pressure differential acts opposite the desired flow direction.

Ball Valve - ball-shaped valve with conduit port and 90 degree rotation. Normally full port with minor pressure loss.

Barrel - unit for volume of oil, the standard barrel contains 42 gallons.

Base Load - minimum load.

Battery - Equipment used to process or store crude oil from one or more wells.

Bernoulli's Equation - relates to the total energy at two points in an incompressible liquid flowing at a steady rate.

Bernoulli's Principle - liquid pressure is inversely proportional to the square of liquid velocity.

Best Efficiency Point (BEP) - point on the speed-efficiency curve where the pump or compressor is operating at its highest efficiency.

Bleed Off Line - Component of pressure containment system on a snubbing stack to drain cavity and reduce trapped wellbore pressure.

Block Valve - valve that is either open or closed; used to isolate equipment or pipeline sections.

Blooiie Line - Large diameter flow line for air or gas drilling that diverts the flow of air or gas from the rig into a pit area.

Blow Down - To vent off gas in a well.

Blowout - A condition when hydrocarbon containment of a wellbore is lost. Oil and gas 'blow wild' at the surface.

Blowout Preventers (BOPS) - High-pressure wellhead valves equipped to shut off the uncontrolled flow of hydrocarbons.

Booster Pumps - mechanical devices used to raise the head of liquid to meet minimum head requirements of the main line pumps downstream.

Borehole Pressure - Total pressure exerted in the wellbore by a column of fluid and /or backpressure imposed at the surface.

Brake Horsepower (BHP) - effective (useful) horsepower developed by an engine brake.

Branch - See lateral.

BTU - British Thermal Unit; the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. Equivalent to 252 calories or 778.2 foot-pounds.

Bubble Flow - A multiphase fluid-flow regime. The gas phase exists as bubbles distributed through the liquid phase. Where the bubbles coalesce and form a less uniform distribution of the gas phase, slippage will occur between the phases.

Bull Heading - The practice of pumping into a closed – in well without returns, or forcing fluid down a well under pressure.

Butterfly Valve - relatively flat, rotating disc mounted on a bearing that allows it to rotate its axis.

Bypass Valve - ON/OFF valve that allows fluid to bypass a station when open, and forces fluid to enter a station when closed; operates together with the station inlet valve.

C.

Can-type Vertical Pumps - pump where liquid enters through the inlet valve and flows to the can bottom increasing the pump suction head.

Capacity - volume of fluid per unit time that the pump or compressor can move.

Capacity Control - use of varying operating speeds to control the volume of fluid moved under certain given conditions.

Carbon Dioxide/Monoxide - Naturally occurring substances resulting from combustion of hydrocarbons. Are also found as components in hydrocarbon reservoirs.

Cascade Shutdown - gradual shutdown of the units in a station where the units are shutdown one by one in specified intervals.

Case Remote Warning (CRW) - high case pressure warning alarm level.

Casing Burst Pressure - The amount of pressure that, when applied to casing causes the casing to fail. Especially important in terms of gas kicks due to the increased pressure exerted by the gas as it comes towards the surface and expands.

Casing Pressure - is the pressure between the casing and drill pipe or casing and tubing in a well.

Cathodic Protection - type of protection that prevents external corrosion; it consists of setting up a current around the line or vessel to reverse the flow of electrons and thus inhibit corrosion.

Cavitation - is when the fluid pressure in the line or vessel drops below the vapor pressure of the liquid being transported resulting in the rapid formation and collapse of vapor bubbles in a flowing liquid.

Cavitation Index - ratio of pressure drop across the valve divided by the difference between the inlet pressure and the vapor pressure of the liquid. Valve selection to ensure operation above the cavitation point is the primary use.

Cellar - A pit beneath the rig floor to provide additional height between the rig floor and the wellhead and to allow the installation of the bops / rotating head / rotating diverter, rat hole mouse hole etc.

Centrifugal Compressor - uses a rotating impeller to increase the pressure of a gas.

Centrifugal Pump - rotating machine device that uses centrifugal force to convert mechanical energy into pressure or head.

Centrifugal/Gear Pump - pump used to draw the crude oil at a constant pressure and flow rate.

Centripetal Force - pulls or pushes an object towards the center of a circular path.

Certified - components manufactured and maintained under a quality control program to ensure conformance with design specifications.

Check Valve - a valve that allows flow in one direction only.

Choke - A device with a fixed (positive) or variable (adjustable) orifice installed in a line to restrict the flow and control the rate of production from the well.

Choked Flow 1) operating condition that occurs when pressure at the vena contracta drops below the liquid vapor pressure and the liquid starts to vaporize and form bubbles; 2) operating condition that occurs when the fluid velocity reaches its sonic velocity in the equipment and no additional flow can be handled.

Choke Manifold - Used to control flowing pressure from underbalance well. May be used on connections or trips to either keep production from displacing the drilling fluid (HP gas wells), or to artificially charge the annulus to avoid loading to reservoir pressure equilibrium (prolific oil wells).

Christmas Tree - The collection of fittings and valves, on the top of the casing, controlling the hydrocarbon production rate.

Clearance - percentage of the swept volume of gas through a reciprocating compressor that remains within the cylinder (see also: sweep).

Closed Returns System - Flow path from the drill string non-return valves (floats) to the rotating control device and flow choke that can hold pressure.

Coating - material applied to the pipe to help prevent corrosion or erosion.

Coefficient of Thermal Expansion - incremental increase in the volume of a unit of fluid for a rise in temperature.

Column Separation - condition that occurs in areas of low pressure, where a large number of bubbles coalesce and form a vapor cavity.

Comm.-out - communication outage; loss of communications from one or more stations requiring operation of those stations without analytical data.

Compressibility - change in volume and density of a fluid with respect to changes in pressure and temperature.

Compression Ratio - ratio of absolute discharge and absolute suction pressures

Continuity Equation - equation to balance mass in a closed system. Prevents mathematical destruction or creation of mass in the system.

Condensate - Light hydrocarbon liquid obtained by condensation of hydrocarbon vapors. Consists of varying proportions of butane, propane, pentane, and heavier fractions with little or no ethane or methane.

Connection Gas - The small amount of gas that enters a well after stopping the mud pumps for a connection.

Constant Bottom Hole Pressure (CBHP) - Methodology within MPD, Proactive Category; whereby bottomhole pressure is kept constant during connections to compensate the loss of AFP when mud pumps are off.

Typical methods include:

1. By keeping continuous circulation during connections.
2. By trapping annular pressure prior to shutting down mud pumps.
3. By diverting mud pump flow across the wellhead.

Constant Choke Pressure Method - The adjustment of choke size to maintain constant casing pressure. Used in well killing operations where the influx is composed of water, does not work with gas due to expansion of the gas as it rises up the wellbore.

Control - imposition of operational limits to the separation system.

Control Panel, - Master or Primary - A manifold system of valves which is usually situated at the power source, which may be operated manually or by remote control, to direct pressurized fluids to well closing devices.

Control Panel – Remote or Secondary - A system of controls usually convenient to the driller, used to actuate controls at the Master or Primary panel.

Control System - system where a comparison between a measured control variable a set point prompts an action to achieve the set point.

Control Valve - valve position determined by a control system based on a set point.

Cooling - process to lower the temperature of the fluid.

Critical Flow - fluid flow that is unstable, alternating between laminar and turbulent flow; Critical flow occurs at Reynolds numbers between 2000 and 4000.

Critical Point - location on a line or vessel that determines the rate at which the fluid in the line or vessel can flow.

Critical Pressure Differential - difference between the pressure at the valve inlet and at the vena contracta that would cause cavitation.

Critical Velocity - speed to maintain turbulent flow and prevent transition to laminar flow.

Critical Zone - see: critical flow.

Cup Tester or Cup Packer - Device lowered into the well on a drill stem to pressure test casing and blowout preventers. The sealing component is cup - shaped, hence the name.

Cyclic Surging - small surges of pressure that oscillate within the line or vessel; cyclic surges are associated with line or vessel equipment, such as reciprocating pumps/compressors and pressure reducing valves.

D.

Darcy Equation - mathematical relationship used to determine a simple system curve.

Dead Band - how far a device can move within its mechanical linkage before it triggers a reaction.

Degasser - Equipment that removes undesirable gases from a liquid, especially gases entrained in drilling or completion fluids. Relies on pressure reduction or inertia to accomplish separation of liquid and gas phases.

Degree-day - measure of the extent to which the mean daily temperature varies from an assumed base, usually 65° F; one degree day is counted for each degree of variation.

Degree of Tolerance - value assigned by an operator for a change in system conditions (magnitude) over a given time (interval) for the present state of the system (steady state or transition).

Dehydration - removal of water vapor from gas.

Dehydrator - vessel used to remove water vapor from gas.

Densitometer - instrument that measures its fluid density.

Density - mass of a substance per unit of volume.

Design Capacity - maximum average capacity of the line or vessel calculated assuming ideal operating conditions.

Design Pressure - Maximum pressure ratings for a pipe or vessel based on its specified minimum yield strength (SMYS), diameter and wall thickness, operation zone, and weld joint type.

Determined Viscosity - actual measurement of viscosity taken with a viscometer.

Differential Head - increase in head between the suction and discharge nozzles of pumps or compressors (see also: head).

Differential Pressure - The difference in pressure between the hydrostatic head of the drilling fluid in the fluid column, and the pressure exerted by or from the formation at any given depth in the hole. May be positive, zero, or negative with respect to the hydrostatic head.

Discharge Control - control based on the limits of the station discharge pressure.

Discharge Nozzle - port through which fluid leaves the pump or compressor.

Discharge Pressure - fluid pressure as it leaves a pump, compressor, or valve.

Discharge Pressure Allowable - pressure allowable that specifies the pressure that triggers the simultaneous shutdown of all the units.

Discharge Set Point - the set limit for discharge pressure allowed to exit the station.

Discharge Valve - OPEN/CLOSED valve, such as a gate valve or a ball valve, that allows or disallows fluid from leaving a pump or compressor.

Displacement (compressor) - volume displaced by each stroke of a piston in a reciprocating compressor cylinder.

Displacement (pipe) - physical volume of a pipe section, usually in cubic feet.

Displacement Meter - a type of meter that measures flow based on the physical displacement of fluid.

Diverter - Typically a device attached to the wellhead or marine riser to close the vertical access and direct any flow from the well away from the rig. The line running from the diverter may be referred to as the "Blooie line"

Downhole Pumping MPD - A pump of some design is used downhole to apply upward lift to annulus returns; to offset annulus friction pressure when circulating, to return riserless drilled mud and cuttings to the rig, or mud riser to reduce the hydrostatic head of mud and cuttings in ultra-deep water.

Down Surge - line or vessel pressure surge, which is negative because its magnitude is below the normal operating pressure of the line or vessel.

Drafting - process of delivering more gas than is presently entering the system.

Drag - another term for frictional loss often associated with the AGA flow equation.

Drag Reducing Agents (DRAs) - long-chain organic molecules in a hydrocarbon or water base injected into line or vessels to reduce frictional losses.

Draining - decrease in volume of fluid in the line or vessel due to lack of pressure.

Drill Stem Safety Valve - An essentially full - opening valve used to close off the drill pipe and prevent flow up the drill string. Kept on the drill floor, and has threaded connections matching the drill pipe in use.

Drill Stem Test - A procedure to determine the productive capacity, pressure, permeability or extent (or a combination of these) of a hydrocarbon reservoir. While several different proprietary hardware sets are available to accomplish this, the common idea is to isolate the zone of interest with temporary packers. Next, one or more valves are opened to produce the reservoir fluids through the drillpipe and allow the well to flow for a time. Finally, the operator kills the well, closes the valves, removes the packers and trips the tools out of the hole. The test may be short (one hour or less) or long (several days or weeks) depending on the requirements and goals. Also there might be more than one flow and pressure buildup periods.

Drilling Spool - BOP stack connection, with flanged ends, used as a spacer between bop equipment, may or may not have side outlets for connection to auxiliary lines

Drooping Characteristic Curve - head developed at shut-off is lower than that on another part of the curve for pumps.

Dry Gas - Natural gas composed mainly of methane with only minor amounts of ethane, propane, butane, and minimum heavier hydrocarbons in the gasoline range.

Dual Gradient (DG) - Creation of multiple pressure gradients within select sections of the annulus to manage the annular pressure profile. Methods include use of pumps, fluids of varying densities, or combination of these.

Dynamic Fluid Flow - see transient flow.

Dynamic Head - kinetic energy of a fluid due to its velocity.

E.

Effective Horsepower - power reading based on the pump or compressor usage.

Effectiveness - measured in terms of line or vessel balance. With stable flow rate, volume in equals volume out, and an even pack exists throughout.

Efficiency - 1) ratio of the friction for a fluid moving through an ideal pipe to the friction for a fluid moving through an actual pipe 2) measure of how well a pump or compressor converts shaft horsepower into pressure and flow. More specifically, efficiency is the ratio of the hydraulic horsepower delivered at the discharge to the actual horsepower supplied to the shaft.

Elevation Head - potential energy per unit weight of a fluid because of its elevation above a reference level.

Elevation Pressure - pressure due to weight of a fluid over a change in elevation.

Elevation Profile - elevation of the flow path above a datum.

Elastomer Seals - all rubber components containing any wellbore pressure in the BOP, wellhead, casing, or separation system.

Emergency Shutdown Valves. (ESD) - Typically remotely actuated valves, preferably gate, butterfly or plug, mounted to outlet on flow cross. Valve is functioned in cases of unplanned release of well returns due to breach in flow back system. Actuated by air, hydraulics, or electrical signal over hydraulics. .

Energy - ability to do work.

Energy Consumption - quantity of energy consumed and measured in hours, such as horsepower-hours and kilowatt-hours.

Entrained Gas - Formation gas entering the drilling fluid in the annulus, causing gas cut mud.

Equal Percentage Valve - valve where the percentage change in fraction corresponds to the increased flow percentage, used normally as control valves Best results occur in the 30-70% open range.

Equalize - static (no flow) condition that occurs when pressures become constant.

Equalization Line or Loop - line providing the means to equalize pressure across a valve, BOP element or other pressure containing device.

Equivalent Mud Weight (EMW) – The pressure at any given depth expressed in terms of mud density at that given true vertical depth.

Error Signal - a signal generated by the controller equal to the difference between the set point and the sensor provided information.

Established Reserves - Portion of the discovered resource base (under anticipated economic conditions) estimated to be recoverable.

Euler's Equation - determines theoretical pump head available from a pump.

Expected Capacity - expected volume the line or vessel flows during a period.

F.

FMEA - Failure modes and effects analysis. A technique for determining the ways in which equipment can fail and the consequences of the failure on reliability and safety.

Feed – in - Fluid flow from formation into well bore.

Feedback Control System - type of control system, also called a closed loop or bump-less system, where the control system receives or uses the information collected to control the process.

Final Control Element - part of a control system that actually affects what is happening in the control system.

Flash Point or Flashpoint - temperature that a liquid releases sufficient vapor to form a mixture with air ignitable by a flame.

Flashing - when a pressure drop causes the fluid to become gas-liquid mixture that continues to flow within a line or vessel.

Flat Characteristic Curve - head developed at shut-off is only slightly greater than that at the design capacity.

Flare Line - Leads from pressure vessel, and is sized according to the pressure rating of the vessel. Contains a backpressure valve that maintains desired pressure on the pressure vessel. Manifolding before the flare line allows gas to feed a pipeline compressor.

Flare Stack - completes the gas separation process and may be 10 to 100 feet high depending on production rates and gas composition. Careful decisions on height and placement of the flare stack are very important for personnel / equipment safety. May have auto ignition facility.

Flow - volume of fluid moving in a given direction per unit of time.

Flow Back System - typically consists of flow cross, flow diverter, emergency shut down valve (ESD), flow line, choke manifold, sample catcher, phase separation vessels, shipping pumps, flare line, flare stack.

Flow Cross - first item of ancillary equipment coupled with the rig's primary well control equipment. A flanged spool with one or two flanged outlets and is typically located between the rig's upper spherical preventer and the flow diverter

Flow Characteristic - describes how the valve operates when opened to different percentages.

Flow Chart - 1) diagram that shows logic, choices, and results of each step of a program with symbols and standard English 2) chart showing flow delivery into or out of a line or vessel.

Flow Computers, Totalizers and Indicators - Computers and totalizers integrate the functions of flow and temperature measurement, computation, alarms, data acquisition, input and output standardization, and closed loop control. They require external sensor input to function.

Flow Control - operational limit based on the line or vessel flow rate through a station.

Flow Controllers - A controller is a device that operates automatically to regulate a controlled variable. Flow controllers regulate flow direction and velocity.

Flow Diverter - installed at the top of the BOP above the flow cross. Function is to divert returned fluids away from the drill floor. There are two types of flow diverter -

- (A) Passive - creates a friction fit seal between the rubber element and the drill string. Tension in the rubber element and well pressure maintains the seal.
- (B) Active. Active diversion relies on external hydraulic pressure to create a seal between the element and the drill string. A Hydraulic regulator is required to maintain the seal in the face of changes as different components pass through the element. This method requires an oil regulator, accumulator, charging pump and hydraulic controls.

Flow Drilling – An underbalance technique where liquid hydrocarbons are returned to surface and separated by a skimmer system

Flow Indicators Sight - Sight flow indicators provide a quick, reliable and economical way to verify the flow of fluids through industrial process lines.

Flow line - Conduit for well returns routed from the wellhead to the choke manifold and from the wellhead to processing equipment. Considerations of design include size, connections, geometry, and pressure rating and anticipated flow conditions.

Flow Meters and Sensors - Flow meters and flow sensors are devices used for measuring the flow or quantity of a moving fluid or gas.

Flow Meter Gas Volumetric - Gas volumetric flow meters measure the flow or quantity of a moving gas in terms of volume per unit time (ACFM).

Flow Meter (Gas & Liquid Mass) - Gas and liquid mass flow meters measure the flow or quantity of a moving fluid or gas in terms of mass per unit time (lbs per hour).

Flow Meter (Gas & Liquid Velocity) - measure the flow or quantity of a moving fluid or gas in terms of velocity (e.g. feet per second).

Flow Meter Liquid Volumetric - measure the flow or quantity of a moving fluid in terms of volume per unit time (gpm).

Flow Sensors Air Velocity - These flow sensors measure air velocity or volume flow using insertion probes or capture hoods.

Flow Straightener – line or vessel flow straightener that lessens any whorls or eddies in the flow that might decrease the accuracy of the meter measurement.

Flow Switches Gas & Liquid Mass - A device with a switch output based on the measured flow of a moving fluid or gas in terms of mass per unit time (e.g. kilograms per hour).

Flow Switches Gas & Liquid Velocity - A device with a switch output based on the measured flow of a moving fluid or gas in terms of velocity (e.g. feet per second).

Flow Switches - Gas Volumetric - A device with a switch output based on the measured flow of a moving gas in terms of volume per unit time (for example, cubic feet per minute).

Flow Switches - Liquid Volumetric - A device with a switch output based on the measured flow of a moving liquid in terms of volume per unit time (for example, gallons per hour).

Fluid Flow - State in fluid dynamics of fluid in motion determined by fluid type, properties, geometry and velocity.

Foam - A two-phase system where the dispersed portion is air. Applied to UBD in water sensitive formations. Recyclable foams are available.

Formation Pressure - The pressure at the bottom of a well when shut-in at the wellhead.

Formation Water - Salt water underlying gas and oil in the formation.

Fracturing - A method of breaking down a formation by pumping fluid at very high pressures.

Friction – resistive force of particles sliding over one another damping out motion.

Friction Factor - determined experimentally or empirically by correlating the Reynolds number and the pipe relative roughness to the fluid friction in a flowing pipe; used by some flow equations to calculate pipe pressure loss.

Friction Head Loss - resulting loss of head pressure due to friction in a fluid flowing in a pipe; the head is converted to thermal energy.

Frictional Pressure Loss - difference between the upstream discharge pressure and downstream suction pressure due to friction; the amount of energy lost between nodes depends on flow rate, pipe size, and fluid characteristics.

Fundamental Flow Equation - gas flow equation using a calculated friction factor.

G.

Gage Joint - the heaviest wall casing in the well usually located just beneath the preventers or tree.

Gas - state of matter that has no definite shape or volume.

Gas Buster - Slang for mud / gas separator.

Gas Cut - gas entrained in a drilling fluid.

Gas Horsepower - total horsepower available to a compressor before derating for mechanical and thermal inefficiencies.

Gas-Lift Mandrel - A gas-lift system assembled with the production tubing string to provide a means of deploying gas-lift valves. The position or depth of the gas lift valves is crucial to the efficient operation of the entire system. Consequently, proper assembly of the gas lift mandrels within the completion tubulars is essential. A port in the gas-lift mandrel provides communication between the lift-gas supply in the tubing annulus and the production-tubing conduit.

Gas/Oil Ratio - The volume of gas at atmospheric pressure produced per unit of oil produced.

Gate Valve - valve that closes by lowering a flat plate or gate to block the flow through the valve.

Gauge Pressure - pressure relative to atmospheric pressure.

Globe Valve - valve that opens or closes when a plug attached to the stem moves linearly in the spherical valve body.

Glycol - dihydric alcohol where different carbon atoms bond to the two-hydroxyl groups. The general formula for a glycol is $(CH_2)_n(OH)_2$.

Graph - visual method of showing the relationship between two or more characteristics.

Graphical User Interface (GUI) - Computer program user interface using graphics to control the software.

Gravitational Energy - potential energy caused by changes in elevation.

Gravimeter - device to measures the specific gravity of a fluid.

H.

Hard Shut In - to close in a well with the bop having the choke or choke line valve closed.

HAZID – Hazard Identification Study. .

HAZOP – Hazard Operability Study. .

Head - potential energy exerted by a column of liquid that has the ability to do work; expressed as the vertical height of the column.

Head Pressure - pressure exerted on a unit area by a column of liquid.

Head-Capacity Curve - graphical representation of the relationship between the head and the flow rate for a centrifugal pump or compressor.

Header - 1) collection of valves or short pipes connecting all the flow line in a given area; 2) modeling term for a short pipe which is treated as a steady state device in transient programs.

Heat Exchanger - vessel that permits heat exchange between hot and cold fluids.

Heater - device that increases the temperature of the fluid flowing through the heater.

Heater-treater - vessels that use heat to separate water from emulsion.

High Recovery Pressure Control Valve - valve that recovers a significant percentage of the pressure differential from inlet to the vena contracta.

High Signal Converter - relay that compares two error signals, selects the highest one, and sends this to the final control element.

High Vapor Pressure (HVP) - liquid hydrocarbons with vapor pressure above 50 psi (340 kPa) absolute at 100°F (38°C).

Horsepower - unit of work that represents the amount of work required to raise a one-pound weight 33,000 feet in one minute.

Hot work - Work done when hydrocarbons are present or probable. See API RP 500

HSE MPD - The adoption of MPD tools or processes for health, safety, or environmental considerations.

Hunting - constant movement of a control system around the set point.

Hydrocarbon - chemical compound composed solely of carbon and hydrogen.

Hydrostatic Pressure - See Hydrostatic head.

Hydrates - solids (ice) that form when water vapor in gas cools; can be a high temperature based on the amount of CO₂ and H₂S.

Hydraulic Gradient (grade line) - graphical representation of the change in pressure or head with respect to distance along the line or vessel.

Hydraulic Head - pressure exerted by the weight of a column of liquid.

Hydraulic Horsepower - actual energy imparted to fluid flowing through a pump or compressor.

Hydraulic Profile - hydraulic gradient.

Hydraulics - set of laws governing the behavior of fluids at rest and in motion.

Hydrocarbon - Chemical compound composed solely of carbon and hydrogen. A catchall term used mainly for oil, gas, and condensate.

I.

Inside BOP - installed in a drill string to prevent a blowout inside the string. Inside BOPs are essentially a check valve preventing flow up the drill string while allowing flow down the drill string. Also called Internal Blowout Preventer, and IBOP.

ID - inside diameter of a pipe. Calculated by the difference between the nominal (outside) pipe diameter and twice the wall thickness (w.t.).

Impeller - rotating part of a centrifugal compressor/pump that imparts kinetic energy to a fluid.

Incompressible Fluids - fluids having very little change in volume as pressure is significantly increased or decreased.

Indirect Heater - vessel that heats a fluid without using a direct flame.

Induction Motor - motor that uses current induced into the rotor by electromagnetic fields in the stator.

Inertia - force that keeps a stationary body from moving and a moving body from changing speed or direction.

Injection - process of accepting commodity into the system.

Instantaneous Measurement - value of the measurement at a specific instant in time.

Instrument - device that reads and records specific information about line or vessel condition and operation, including pressure or temperature sensors, meters or detection devices.

Intake Nozzle - suction nozzle.

Interlocks - software or hardware that allows or prevents motors from starting, or valves from opening or closing.

J.

Jetting the Well in - circulating a lower - density fluid to allow the well to go underbalance, either to drill in underbalance mode or to induce production from the formation.

K.

Kelly Cock - valve installed between the swivel and the Kelly to prevent high-pressure backflow. Closing the valve keeps pressure off the swivel and rotary hose.

Kelly Valve Lower - an essentially full opening valve below the Kelly, with an OD same as the drill pipe.

Kelvin - metric absolute temperature unit (degrees Celsius + 273.16).

Kick - Unplanned, unexpected influx of liquid or gas from the formation into the wellbore, where the pressure of fluid in the wellbore is insufficient to control the inflow. If not corrected can result in a blowout.

Kill - Action taken to kill well and prevent or correct blowout. Includes circulation of heavy weight fluid downhole, circulating kick out, and closing of blowout preventers.

Kill Line - High-pressure line between the mud pump and the blowout preventer to facilitate the pumping of fluid into the hole to overcome well pressure with the preventers closed.

Kill Rate - A predetermined fluid circulation rate expressed in volume per unit of time that is used under kick conditions, often a selected fraction of the circulating rate time unit used while drilling under normal conditions.

Kill Rate Circulating Pressure - Pump pressure required to circulate kill rate volume under well kick conditions.

Kinematic Viscometer - a device that measures efflux times in determining kinematic viscosity.

Kinematic Viscosity - the ratio of a fluid's absolute (dynamic) viscosity to its density.

Kinetic Energy - energy an object has because of its motion.

L.

Laminar Flow - fluid flow where fluid layers at the center of the line or vessel move faster than the layers next to the pipe wall.

Law of Conservation of Energy - prohibits creation or destruction of energy. Work changes energy from one form to another (heat to mechanical).

Leak Detection - examining and reporting any anomalies in the line or vessel hydraulics.

Line Fill - sequence of commodities in the line.

Line Looping - see: loop and looping.

Line Pack or linepack - 1) volume of fluid in the pipe at flowing pressure and temperature; 2) increased volume of a fluid within a given pipe due to increased pressure.

Line Section - segment of line or vessel between two terminals.

Linear Valve Flow Characteristic -proportional increased flow by equal opening increments of the valve.

Line Break Detector - automatic valve operator that activates if the rate of pressure drop exceeds a pre-set amount, thereby limiting fluid loss to the section in which the line break occurs.

Line Pack - increase in volume of fluid in the line or vessel caused by an increase in pressure

Liquid - one of the three states of matter; has a definite volume, but no definite shape.

Liquid Leak Detectors - Liquid leak detectors sense when a liquid is leaking from a pipe, tank, or other receptacle area.

Liquefied Natural Gas (LNG) - Oilfield or naturally occurring gas, chiefly methane, liquefied for transportation.

Liquefied Petroleum Gas (LPG) - fluid consisting mainly of ethane, propane and butane that are gases at atmospheric pressure but under high pressure are liquids.

Load Factor - ratio of the average demand to the peak demand.

Load Profile - manner that the fluid flow varies over a given period.

Load Shifting - moving an entire load from a peak time to an off-peak time.

Look-ahead Model - projects flow transients into the future, based on current operating conditions and any specified schedule of events; if any constraint violations occur, alarms activate to initiate preventative actions.

Loop - sections of pipe that parallel the existing line to increase the capacity and efficiency of a line.

Loop Swing - putting a line or vessel loop into or out of service.

Loop-Fill - volume of commodity that fills the out-of-service loop section.

Looping - installation of sections of pipe that run parallel to the existing line and increase the capacity of the line.

Lower Kelly Cock - Also called drill-stem safety valve, see drill-stem safety valve. .

Low Vapor Pressure (LVP) - hydrocarbons with vapor pressure lower than 50 psi (340 kPa) absolute at 100°F (38°C).

Low head - a drilling procedure using underbalance techniques to maintain a reduced hydrostatic head on the formation.

M.

Managed Pressure Drilling (MPD) - 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. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.

➤ MPD process employs a collection of tools and techniques which may mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.

➤ MPD may include control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.

➤ MPD may allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be economically unattainable prospects.

Manifold - a system of pipe and valves that serves to convert separate flows into one flow, to divide one flow into separate parts, or to re route a flow to any one of several possible destinations.

Master Choke Line Valve - the valve on a choke and flow line that is nearest to the preventer assembly, used to stop flow through flow line and choke.

Man Machine Interface (MMI) - interface between an operator and a computer.

Mass - amount of matter that an object contains.

Maximum Operating Pressure (MOP) - maximum pressure permitted for normal line or vessel operation; MOP is related to pipe strength and the pipe's ability to withstand internal pressure. MOP results from the lowest of three factors: design pressure, hydrostatic test pressure, or flange rating.

MAOP - Maximum Allowable Operating Pressure.

MAWP - Maximum Allowable Working Pressure. See MAOP

Mean Effective Pressure - theoretical constant pressure applied during each power stroke to produce the brake horsepower of an engine.

Mean Pressure - average pressure in a flowing line or vessel.

Mean Temperature - average temperature in a flowing line or vessel.

Mechanical Efficiency - efficiency of the mechanical linkage between an engine and the pump or compressor it is driving.

Mechanical Energy - ability to apply a force to an object causing it to move.

Mechanical Losses - friction losses in bearings and stuffing boxes and other rotational contact points.

Mechanical Vapor Plug - used to provide a gas vapor seal when required during pipe replacement and repair.

Mechanical Work - force acting on an object through a distance.

Membrane Nitrogen - Reduced Oxygen content air produced by passing compressed air over a membrane to reduce the oxygen content to 2-5% on average.

Meter - device that measures the amount of fluid entering and leaving a line or vessel system.

Meter Banks - single meters arranged in parallel configurations.

Meter Factor - used to adjust meter readings to show the actual volume measured by the meter.

Meter Multiplier - used when actual voltages or currents are too large for the meter and would be out of range.

Meter Prover - device to test ("prove") meter accuracy and determine the meter factor.

Meter Run - one leg of a meter bank, consisting of a strainer, a meter, and the associated valves.

Meter Stack - device equipped with a set-stop counter that shuts down the unit when reaching the maximum allowable volume.

Metering - measuring the volume of fluid as it moves past a particular point on the line or vessel.

Metering Manifold - array of pipes and valves allowing an operator to redirect the fluid to other pipes or processes.

Mist Drilling - A method of dispersing water, oil or both in air, nitrogen, gas or a combination of the three and used as the drilling fluid.

Momentum - attribute of an object's velocity multiplied by its mass.

Moody Diagram - graph that shows relative roughness, and Reynolds number as a way to determine the friction factor (f) used in the Darcy equation.

Motor - converts electrical energy to mechanical energy in the form of a rotating shaft.

Mud Cap - A variable length fluid column maintained above a formation that is taking the circulating fluid and drilled cuttings.

Mud Flow Indicator - Device that continually monitors and records the mudflow from the annulus and out of the mud return line.

Mud Gas Separator - device that separates free gas from mud also known as a Gas Buster.

Mud Return Line - A trough or pipe, usually pipe, running from the surface connection at the wellbore to the header boxes for the shale shakers at the start of the solids control system.

Multi-stage Pump - pump that has two or more impellers mounted on the same shaft and an equal number of liquid pressurization stages.

N.

Natural Gas - Typical composition is (approximate percentages) 80% methane, 7% Ethane, 6% Propane, 2.5% Butane, 1.5% Isobutane, and 3% Pentane. Used in UB Drilling where it is available from local pipelines or other sources at reasonable cost. Has advantage of eliminating downhole corrosion and combustion problems, but surface handling presents safety issues during connections and tripping.

Natural Gas Liquids (NGL) - petroleum fluid primarily composed of ethane, propane, and butane.

NGL is a gas at atmospheric pressure but transported as a liquid by maintaining it under high pressure.

Near Balance - A drilling procedure using underbalance techniques to keep the bottom hole pressure near the pore pressure. This technique is often used in very sour wells.

Needle Valve - A globe valve incorporating a needlepoint disc that allows extremely fine flow control.

Net Positive Suction Head (NPSH) - head above the vapor pressure of the liquid existing at the pump suction nozzle.

Net Positive Suction Head Available (NPSHA) - actual NPSH available at the pump suction for the particular operating conditions; NPSHA is the difference between NPSHR and NPSH.

Net Positive Suction Head Required (NPSHR) - minimum NPSH required by the pump to prevent cavitation.

Net Pumping Requirement - total volume of commodity that the line or vessel must pump every day of the month through each section of pipe in order to meet the Notice of Shipment.

Net Standard Volume - volume of a fluid at standard pressure and temperature after the deduction of S&W.

Network - system model of pipes and equipment.

Nitrogen, (NO₂) cryogenic - inert gas, satisfies the operational requirements of underbalance drilling in terms of safety and operational flexibility. Can be expensive in underbalance operations due to transportation, storage and volume requirements.

Node - connection point between different devices in a pipeline model.

Non-Recoverable Energy - head between the total energy head line and the total head line; energy that is no longer useful for moving oil down the line or vessel because it has been converted to heat and absorbed by the ground surrounding the line or vessel.

NRV - A non-return valve. A float or other check valve in the system. See Inside BOP

NPSHR Capacity Curve - shows the relationship between NPSHR and capacity.

O.

OD - outside diameter of a pipe.

Off-line Model - may be steady state or transient, but does not have access to SCADA data. Typically requires manual inputs.

Oil and Gas Separator - Equipment used to separate liquid phase of well production from the gas components. Separators may be vertical or horizontal, and are cylindrical or spherical in shape. Separation occurs essentially by gravity with the heavier liquids falling to the bottom and the lighter phases (gas) rising to the top.

Online Model - uses real-time telemetry (SCADA) to retrieve current operating data.

Operator - the Company having legal authority to drill wells and undertake the production of hydrocarbons. The Operator is often part of a consortium and acts on behalf of this consortium.

Operating Capacity - average sustainable flow rate over specified periods taking into account routine and unexpected maintenance and operating problems.

Operating Limits - Set of limits for a section of line or vessel established to prevent over-pressuring.

Operating Point - point of intersection between a pump head-capacity curve and a system curve. This value is the maximum flow rate that a given pump can maintain in the line or vessel.

Optimization - selection of the most desirable combination of factors to meet a specified objective.

Optimizer - software that uses mathematical techniques to meet objective functions.

P.

Pack Off or Stripper Preventer - Preventer having an element or packing material that relies on pressure from the wellbore for closure. Used primarily to strip pipe through the hole or allow pipe movement with pressure on the annulus.

Pack Off or Stripper - Device with elastomer packing element that depends on pressure below the packing to create a seal in the annulus. Used primarily to run or pull pipe at low or moderate pressure.

Panhandle Formula - empirical equation used for calculating flow in gas pipelines; two versions are Panhandle "A" (partially turbulent) and "B", sometimes-called Modified, (fully turbulent).

Parallel Operation - configuration where pump or compressor capacities are additive while the head remains constant.

Parasite (string, casing) - Annulus or ID used to inject fluid at some depth below surface. The use is very similar to a gas lift mandrel.

Partial Pressure - pressure a fluid would exert if it alone were present in the container.

Pascal's Laws - pressure acts uniformly in all directions on a small volume of liquid; in a liquid confined by solid boundaries, pressure acts perpendicular to the boundary.

Peak Shaving - 1) technique used to shift a portion of an electrical load at a peak time of day to a non-peak time; 2) technique used to meet peak demands using alternate gas supplies such as storage, LNG or propane air.

Piezometric Pressure - pipe pressure plus elevation pressure.

Pig (pigged) - device, which may contain instruments, propelled by fluid down the line to clean pipe walls, gather information about the pipe, or separate different batches of fluid.

Pig Time - time required for a "pig" to traverse a section of line or vessel.

Pipe Leg - modeling term.

Pipe light - a condition when the force acting on the drillstring from the wellbore pressure exceeds the weight of the drillstring.

Pipe Prover - common device used in the proving of a meter.

Pipe Work (surface pipe connections) - May be threaded, unions, clamps, or flanged. Flanged connections are preferable (not mandatory) especially in the higher pressure applications, unions and clamps are acceptable in low to medium pressure, threaded connections are appropriate in low pressure operations only and care must be taken to avoid galling / thread damage.

Piping and Instrumentation Diagram (P&ID) - diagram showing the sequence of piping and instruments on a section of the line or vessel but not drawn to scale.

Pit Level Indicator - Device that constantly monitors the level of drilling fluid in the pits during operations incorporates float devices with sensors that report levels to a recording and alarm device (the pit volume recorder) placed near the driller's position on the rig floor, the alarm is set to sound if the pit level goes too high or too low.

PLC - Programmable Logic Controller.

Plug Valve - wedge shaped, reduced part valve with 90-degree rotation; causes high-pressure drop.

Pocket (unloader) - reduces the flow through a reciprocating compressor by increasing the volumetric capacity of the compressor cylinder.

Pore Pressure - Pressure exerted by fluids in a formation pore space.

Positive Choke - choke requiring orifice size change to change the rate of flow.

Potential Energy - energy of position (usually the energy input to the system such as at pumps).

Potential or Head Energy - energy that can be converted to velocity or flow; this pressure is created through changes in elevation or by pump units that are equivalent to positive changes in elevation.

Pour Point - lowest temperature at which a liquid will pour, or flow.

Power (p) - rate of doing work.

Power Factor - ratio of real power (measured in Hp (kW)) and apparent power (measured in kVA).

Predictive Model - performs "what if" analyses by calculating the effects of transients introduced by scheduled or unscheduled line or vessel events, such as pump or compressor outages, valve closures, or supply variations. The operator typically enters these events into a "scenario".

Pressure - amount of force (F) exerted on a unit area (A) of a surface.

Pressure Base - assumed atmospheric pressure used in calculations requiring "absolute" pressure. (DATUM)

Pressure Control - operational limit based on either the line or vessel suction pressure or the discharge pressure at a station.

Pressure Control Valve (PCV) - valve that regulates pressures at stations, restricting flow by use of a ball or plug positioned by an actuator.

Pressure Deployment - process of deploying or recovering drill string or coiled tubing components from a live or pressurized well.

Pressure Loss - rate of decrease in pressure along the flowing line or vessel ($P \cdot t$) due to friction of the fluid against the pipe wall.

Pressure Relief Valve (PRV) - a valve that opens automatically to relieve the line pressure that is above the safe operating limit.

Pressure Transient - pressure waves, traveling through the pipes at the wave speed of the fluid and caused by changes in the operation of the system.

Pressure Transmitters - instruments to measure and report pressure.

Pressurizable Mud Returns - See Closed Returns System.

Pressurized Mud Cap Drilling (PMCD) - Variation of MPD, drilling with no returns to surface where an annulus fluid column, assisted by surface pressure, is maintained above a formation that is capable of accepting fluid and cuttings. A sacrificial fluid with cuttings is accepted by the loss circulation zone. Useful for cases of severe loss circulation that preclude the use of conventional wellbore construction techniques.

Pressurized Surge Tank - also called an accumulator; prevents the transfer of pressure waves to other parts of the line or vessel system.

Primary Location Instruments - location where the instruments normally used to monitor flow conditions are located.

Proactive MPD - Using MPD methods and/or equipment to actively control the pressure profile throughout the exposed wellbore.

Process Disturbances - things that change the steady state of a control system profile.

1) Horizontal line that indicates changes in ground elevation along the line or vessel route.

2) Modeling term used to define changes with respect to time.

Productivity Index - The continuous production capacity of a well. PI is a measure of rate (MSCFD) divided by the pressure drop to generate the flow rate (PSI). Index is MSCFD/PSI or Barrels per day per PSI.

PHA - Process Hazard Assessment. An organized and systematic methodology to identify the potential hazards associated with a particular operation, piece of equipment, or total system. Processes commonly used are:

- i) What if
- ii) Checklist
- iii) HAZOP
- iv) FMEA
- v) FTA

Proportional Integral Derivative (PID) - controller that uses all terms in determining the movement to meet the set point.

Pressure Gradient - Change of pressure with depth, usually expressed as pounds per square inch per foot.

A scale of pressure differences in which there is a uniform difference in pressure from point to point.

Pressure Vessel -Phase Separation - First Option.
Single four - phase separation vessel using velocity drop in the first compartment to create gas and solids phase

separation. Liquids cascade to the back compartments where with sufficient residence time the interface forms. Requires sufficient time for the interface between liquids to take place which means the vessel has to be correspondingly large to accomplish the process.

Second Option. A series of vessels designed to separate the phases sequentially. Order of phase separation may vary from system to system. Different systems available are: Gas to be separated first as it is compressible and of lower density than solids or liquids. Remove solids first as they will erode pipe work and components in the system. Separation of gas, solids, and liquids occurs in individual hydro-cyclones connected in series, parallel, or a combination of both. In all separators, the design should make it impossible for gas to travel down the liquid leg and liquid to travel down the gas leg.

Pump Capacity - flow rate of a pump at a particular head as read off the pump head-capacity curve.

Pump Curve - graph that shows the relationship between flow, head, horsepower, efficiency, and NPSHR of a pump.

Pump Differential - total pressure output of a pump minus its suction pressure.

Pump Differential Head - difference in total head between the suction and discharge of the pump.

Pump Head - amount of the increase in total head across the pump. Also referred to as pump differential head.

Pump Head-capacity Curve - graphical representation of pressure produced by the pump vs. flow rate.

Pump Horsepower Capacity Curve - graphical representation of required power versus flow.

Pump Run Out - flow rate that produces little to no head.

Pump Station - one of the installations built at intervals along a liquid line or vessel to route and increase the flow; contains pumps and other equipment.

Pump Unit Lockout - removal from service of a shutdown pump unit.

Pump Unit Shutdown - temporary loss of a pump unit, indicates exceeded one or more of the pump's operating parameters.

Purge - procedure that removes all air from a line or vessel to prevent fire or corrosion. The length of time required to purge a line is dependent on the size and length of the line, size of the blow off valve, and the purging method selected.

PVR (Plant Volume Reduction) - the volume of gas removed from a line or vessel at a hydrocarbon processing plant.

Q.

Quick Opening Valve Flow Characteristic - produces a very rapid increase in flow between the closed position and the partially open position.

R.

Ramping - 1) gradual startup or shutdown of a pump unit.

2) Modeling term meaning to change variables with time.

Rankine (degrees temperature) - English measurement of absolute temperature (+459.69 offset).

Rate of Rise - surge control in which a pressure sensor initiates a device control that is proportional to the rate of pressure increase caused by the surge.

Reactive MPD - Using MPD methods and/or equipment as a contingency to mitigate drilling problems as they arise.

Real-time Model - uses SCADA data to run in lock step with the actual line or vessel. The goal is for calculated flows and pressures to track telemetered points, with consistent and reasonable accuracy, so that confidence can be gained in the model's ability to predict future operating conditions, as well as estimate conditions at non-telemetered locations.

Reciprocating Compressor - 1) a piston-type positive displacement compressor which increases the pressure of a definite volume of gas by reducing the cylinder volume, resulting in a pulsating delivery of gas; 2) any compressor which employs a piston working inside a cylinder to compress a gas; usually has "pockets" that allow for limited pressure and flow control.

Recoverable Energy - head below the total headline; energy which is still useful for moving oil down the line or vessel.

Recycle Line - gas line that allows re-circulation of discharge gas into the suction side of a centrifugal compressor; this permits a centrifugal compressor to be placed on-line or off-line in parallel with other units without creating a surge condition.

Reference Level - zero elevation/head on a total energy diagram. For line or vessel applications, the reference level is usually sea level.

Regulator - control valve used to regulate pressure or flow.

Reid Vapor Pressure - a test method to determine the vapor pressure of volatile petroleum liquids at 100° F with an initial boiling point above 32° F. (ASTM D 323)

Relative Roughness - ratio of the absolute roughness of the inside pipe wall to the internal diameter of the pipe; Absolute roughness is the average height of imperfections in the pipe wall surface.

Relief Valve - valve specifically designed to protect a line or vessel from exceeding MAOP by relieving to atmosphere or a tank.

Remote Choke Panel - A set of controls, usually placed on the rig floor, used to control the amount of fluid circulated out through the choke manifold.

Remote Station - Auxiliary controls for operating a blowout preventer.

Remote Control - line or vessel control achieved at a remote control center using a SCADA system.

Remote Terminal Unit (RTU) - computer located at a remote location that gathers the information provided by all the PLCs at the location, and transmits that information back to the host computer.

Report by Exception - RTU sends information to the Host when data has changed by a specified amount.

Reservoir - An economic hydrocarbon-bearing zone.

Return System - Handles returns from the well - injected fluids, (gas and liquid) cuttings, hydrocarbons, formation

water etc. Consists of flow diverter, flow cross, emergency shut down valve, choke manifold, pressure vessel and solids control equipment, from where the liquid phase used for drilling is passed on to the drilling fluid tank, and then to the rig pumps for re injection to the well.

Reverse Circulation - circulation of drilling fluid down the annulus and up through the drill string.

Reynolds Number - mathematical relationship that describes the interdependence between the pipe diameter, fluid viscosity, and flow velocity; a dimensionless number used to describe the type of flow exhibited by a fluid flowing through a pipe.

Riser - vertical pipe intended to move fluid to either a higher or a lower elevation, such as from the ocean floor to a platform.

Rising Characteristic Curve - preferred curve shape for pump H-Q curves; this curve has a steady increase of H with decreasing Q.

Rotary Motion Valve - valve whose closure member rotates opening or closing rotating equipment, centrifugal pumps, or compressors.

Rotating Diverter - Generic term, - sometimes used to mean rotating head, or rotating blowout preventer.

Rotating Blowout Preventer (rotating annular preventer designed to rotate with pipe and seal on both pipe and kelly while allowing upward and downward movement of the pipe - also known as RBOP) Design specific to underbalance drilling. Models available for both top drive and Kelly drive applications.

Rotating Head, Low-pressure diverter designed to rotate with drill pipe and used mainly in air drilling.

Roughness - measure of the surface condition of the internal wall of pipe; Roughness can change with the age of the pipe and the type of service it has provided.

RTU - remote transmission (terminal) unit used in telemetry (SCADA) systems to transmit operating information to a master terminal unit (MTU) usually located in a control center.

Rupture disc - device that relieves pressure when an absolute pressure value is high enough to rupture the disc material, thus allowing fluid to flow into some type of a vessel.

S.

Safety Valves (pop offs) - valves most commonly used for temperature or pressure relief. Ensure venting from these valves terminate in a safe area.

Sample Catcher - Designed to take a portion of the flow from the wellbore, direct it through a chamber to remove drilled solids but reject liquids and gas.

Scraper - pigging device for cleaning paraffin or other substances from the inside surface of a pipeline. See pig.

Scraper Pig - pig equipped with brushes or urethane blades used to clean line or vessels; see also: pig.

Seat, Casing - designed to ensure that damage or breakage does not result from a hard shut in.

Sediment and Water (S&W) - dissolved impurities such as salt, water, asphalt and other substances in crude

- oil, which come out of suspension and sink to the bottom of a container as the oil cools and settles. .
- Sensor** - instrument used to measure operating information such as pressure, flow or temperature.
- Separator** - horizontal, vertical, or spherical vessel used to remove liquid from gas, and gas from liquid. .
- Series Configuration** - a configuration of pumps or compressors linked together so that the discharge of one pump or compressor enters the inlet of another. Heads are additive at the same flow series/parallel operation flow is divided between the series pumps/compressors and the parallel pumps/compressors according to the capacity of each of the units.
- Set Point** - preset value that is the desired value of a variable, such as suction or discharge pressure.
- Shipping Pumps** - Typically centrifugal in design, used to transport drilling fluids to the suction tank and produced fluids to the storage facility. Mostly activated manually, but some float activated pumps are in use.
- Sight Windows** - Sight windows are an effective and economical way of viewing tank, pressure vessel and piping systems interiors. Also referred to as a sight glass.
- SICP** - Shut in casing pressure.
- Shutdown Valves, Emergency** - used to shut down flow line from rotating head in emergency situations, preferably butterfly or similar quick - closing design See ESD
- Shut-off Head** - head delivered by the pump at zero flow.
- Single Stage Pump** - one impeller and single stage of pressurization.
- Slack Pipeline** - maintaining column separation at a location with an extreme drop in elevation so that the pressure does not exceed the maximum operating pressure (MOP).
- Slug Flow** - A multiphase fluid-flow regime where the gas and liquid phase are discrete over portions of the flow. Generally occurs in combination with bubble flow. Flow will vary from high liquid to high gas cuts. Also called Line Jacking
- SMYS** (Specified Minimum Yield Strength) - the design value of the strength of the steel used in the pipe or vessel.
- Snubbing** - conducting tripping operations when the force acting on the drill string or coiled tubing from the wellbore pressure equals or exceeds the drill string or coiled tubing weight.
- Soft Shutdown** - using the VFD to slow the motor before stopping.
- Soft Shut In** - To shut in a well by closing the blowout preventer with the choke and choke line valve open, then closing the choke while monitoring the casing pressure gage for maximum allowable casing pressure.
- Soft Start** - with VFD, logic circuit increases AC power gradually until the motor has reached full speed.
- Solubility** - capacity of a substance to be dissolved.
- Sonic Flow Meter** - device for measuring fluid flow by timing sound waves across a cross-section of pipe.
- Sonic Wave Speed** - speed at which a transient wave travels through a line or vessel. It depends on fluid properties, and the elastic modulus of the pipe.
- Sour** - Hydrocarbon fluids containing sulfur. Generally taken as greater than or equal to 10-ppm, the 8 hour occupational exposure limit.
- Sour Fluids (handling)** - in underbalance drilling operations, where sour fluids are expected a closed system is utilized to meet recognized industry standards for handling such fluids
- Sour Water (handling)** - water contaminated with hydrogen sulfide (H₂S). Run through a degasser (poor boy, vane type etc) and pass to a tank before disposal.
- Source** - flow into a system.
- Spacer Spool** - used in underbalance operations to adjust height of stack and components on assembly, and to raise or lower height of flow line.
- Specific gravity** - 1) measure which compares the density of any liquid with the density of water at the reference temperature; 2) weight of a given volume of gas compared under standard conditions to an equal volume of dry air.
- Specific Heat** - heat required to raise a unit mass of a substance one degree.
- Specific Heat Ratio** - Ratio of specific heats at constant pressure and constant volume.
- Specific Speed** - design index that gives a general indication of the overall performance and geometry of the pump and impeller.
- Specific Weight** - substance weight divided by its volume.
- Spitzglas Formula** - equation used for calculating flow in small diameter, low-pressure distribution lines.
- Square Law** - relationship between velocity and the pressure drop in the pipe, where for over a limited range of flows, pressure drop is proportional to the square of the velocity for flow rate (also called capacity).
- Squeeze Job** - Remedial operation to pump cement slurry down a well into open perforations, formation cavities etc, to create a blockage..
- Standard Temperature** - temperature used to correct volumes to a standard volume.
- Static** - usually refers to a pipe segment with no flow.
- Static Gradient** - representation of the height of liquid column or static head above the elevation at any point on the line or vessel.
- Static Head** - elevation of a column of liquid above a given reference point.
- Static Head Pressure** - pressure exerted upon a unit area by a column of liquid.
- Static Hydraulics** - refers to the properties of liquids when liquids are at rest and examines how pressure and changes in elevation affect fluid behavior in the line or vessel.
- Static Pressure** - pressure when the system is shutdown.
- Static Resistance** - sum of the elevation head and static head that must overcome before any liquid begins to flow.

Static Fluid Level - the level to which fluid rises in a well when shut in.

Station Bypass - diverting a full or reduced flow in the line or vessel around a shut down station.

Station Differential - pressure difference between the station suction pressure and the station discharge pressure.

Station Suction Valve - ON/OFF valve that allows fluid to enter a station when open, and forces fluid to bypass a station when closed. Operates together with the bypass valve.

Steady State - For steady state to occur the flow into a pipe must equal the flow through the pipe that must equal the flow out of the pipe. Steady state also has no change in flow or pressure with respect to time.

Steady State Analysis - method of flow analysis of a line or vessel system that assumes constant flowing conditions.

Steady State Energy Equation - modification of Bernoulli's equation that accounts for friction and work added by pumps. It compares the energy in a fluid at two different points and accounts for the addition or removal of energy between the same two points.

Steady State Model - performs offline simulation that does not allow for changing line or vessel conditions over time. Stead-state models are the historical norm for facilities planning and quick evaluation of operational situations. It remains an essential step in the transient modeling process.

Steep Characteristic Curve - rising pump H-Q curve, with a large increase in head between the head developed at design capacity and at shut-off storage field.

Studded Block - A solid block of metal bored and studded to accept flanges. Used for erosion points or high stress connections.

Stress Corrosion Cracking - Cracking induced by a combination of stress and corrosion.

Stripper Head - Blowout prevention device consisting of a gland and packing arrangement bolted to a wellhead. Used to seal annular space between tubing and casing.

Stripper Rubbers - Internal component of rotating head used to strip pipe in and out of hole, available for drill pipe and casing sizes, and may be polyurethane composition where required to suit application / conditions e.g., high temperature service, or in certain drilling fluid applications where standard elastomers are inappropriate.

Stripper Well - A well having minimal hydrocarbon production.

Stripping - Adding or removing drill pipe into a live or pressurized well after exceeding pipe light depth.

Stripping In - The process of lowering the drill stem into a well when the well is live.

Stripping Out - The process of raising the drill string out of the wellbore when the well is live.

Storm Choke - A choke that is pre-set to close automatically if flow exceeds its pre-set rating.

Suction Control - control based on the limits of the station suction pressure.

Suction Pressure - pressure at the suction flange of a pump or compressor.

Suction Set Point - required suction pressure necessary for the station.

Suction Valve - ON/OFF valve, such as a gate valve or a ball valve. If the valve is open, fluid can flow into the pump or compressor. If the valve is closed, no fluid can flow into the pump or compressor.

Supervisory Control and Data Acquisition (SCADA) - computer and communications system that gathers and analyzes operating data and sends reports to the control center. In addition, the SCADA system carries out commands issued by the operator at the control center.

Supply - flow into a system.

SCSSV - Surface controlled sub surface safety valve.

SSV - Surface safety valve.

Surge - 1) pressure change produced by conditions such as pump or compressor startup or shutdown, valve openings or closures, and line leaks 2) pulsating flow in centrifugal compressors caused by operating under low flow conditions.

Surge Pressure - rapid change in line or vessel pressure.

Sustainable Capacity - average sustainable flow rate over long periods taking into account routine maintenance and operating problems.

Sweep - a procedure that accelerates gas velocity, or increases gas turbulence, through a specific section of line or vessel, for removing accumulated liquids.

System Curve - line graph that shows how variables like viscosity, density, and flow rate combine with fixed conditions such as length of pipe, inside diameter of pipe, internal roughness of pipe, and changes in elevation influence throughput.

T.

Tension Tool - a retrievable or drillable packer where sufficient pipe weight is not available to set the tool in compression.

Thermal Energy - ability to do work via temperature.

Thermal Expansion - as temperature increases, fluid volume increases thus decreasing the specific gravity.

Throughput - actual flow rate of fluid to flow through the system.

Tie Downs - Used to secure lines and system components on land and offshore drilling rigs, particularly important in underbalance drilling operations, where vibration is encountered. Specialist tie down equipment is available. Also, anchoring device for the deadline of a hoist block arrangement.

Tight System - minimized phase separation at a location with an extreme change in elevation by maintaining sufficient pressure upstream and down-stream of the drop in elevation.

Time Step - each calculation out in time for a transient model.

Torque - force that produces rotation of an object around a point. Also called a couple.

Total Energy Diagram - graphical representation that shows the elevation profile of a line or vessel, with the total head for each batch drawn as a horizontal line above the elevation profile.

Total Energy Head - total head at the beginning of a line or vessel segment.

Total Energy Head Line - horizontal line on the total energy diagram that indicates the amount of total head that is in the liquid at the start of a line or vessel segment.

Total Head - the sum of static head, elevation head and dynamic head. Total head is the total useful energy the liquid has at any point.

Total Line Pressure - gravitational pressure plus pump pressure.

Total Static Head Gradient - sum of the static head and the elevation at any given point in the line or vessel.

Traceability - The ability for parts to traced to their origin. The origin refers to material and place of manufacture.

Transducer - see sensor.

Transient - unsteady (changing) flow or pressure condition that changes with time. A transient can also refer to a transition between two steady state conditions.

Transient Flow - unsteady (changing) flow or pressure condition that changes with time. A transient can also refer to a transition between two steady state conditions.

Transient Analysis - method of flow analysis of a line or vessel system that takes into consideration changing flowing or pressure conditions over time usually using a computer program.

Transient Model - on- or off-line simulation that considers dynamic fluid flow characteristics over a specified time span. Also called unsteady state model.

Transit Time - time it takes the carrier to transport a batch from the supply point to the delivery point.

Transition Flow - multiphase-fluid flow regime characterized by a chaotic mixture of liquid and gas, with neither phase appearing to be continuous. Also known as churn flow, transition flow is an intermediate flow condition between slug flow and mist flow.

Transition Region - flow regime where the fluid flow is turbulent but not fully developed turbulence.

Trip Gas - Accumulation of gas in wellbore while a tripping.

Trip Margin - An incremental increase in drilling fluid density to provide an element of overbalance and compensate for the effects of swabbing.

Tuning - tweaking physical system characteristics until predicted flow and pressure values match actual data.

Turbine Meter - a meter using a multi-bladed rotor to which the fluid imparts a rotational velocity that is proportional to the mean velocity of the stream; counting rotor revolutions derives volume.

Turbulent Flow - occurs when fluid particles in the line or vessel flow in random directions and forward at the same velocity.

U.

UBD Zone - section of well, in the context of Underbalanced Operations, where performing UBD.

Ultimate Potential - An estimate of recoverable reserves produced by the time all exploration and development activity is completed.

Underbalance - A condition where the pressure exerted in the wellbore is less than the pore pressure in any part of the exposed formations.

Underbalanced - Conducted in a state of underbalance.

Underbalanced Drilling (UBD) - A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.

Underbalanced Operation (UBO) - A well construction or maintenance activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.

Unloader - See: pocket unloader.

Upsurge - positive pressure surge. Upsurge pressure is above the normal operating pressure.

V.

Valve - device used to stop or control the rate of flow in a line or vessel or to serve as an automatic or semiautomatic safety device. Common valves include the butterfly, gate, plug, globe, needle, check, and pressure relief.

Valve Actuators - General - devices that, in response to a signal, automatically move the valve to the desired position using an outside power source.

Valve Actuators Manual - by definition, require no outside power source.

Motor Actuators Electric/Electronic - Valve actuators using a motor to drive a combination of gears that generates the desired torque or thrust level.

Valve Actuators Pneumatic - Pneumatic valve actuators that convert air pressure into motion.

Valve Actuators Hydraulic/Electro-hydraulic - Hydraulic and electro-hydraulic valve actuators convert fluid pressure into motion.

Valve Flow Coefficient - specifies the friction coefficient for a valve.

Valve Positioners - Valve positioners compare the control signal to the actuator's position and move the actuator accordingly.

Valve Position Indicators - are devices that show the position of the closure element.

Vaporization - a change of state from liquid to gas.

Vapor Pressure - For a given temperature, the pressure that maintains a liquid and its vapor in equilibrium.

Variable Frequency Drive (VFD) - electric motor that adjusts its speed by adjusting the frequency of AC power.

Variable Speed Drive – A system using a VFD. Pumps that use VFD have the same system curve but the changed rotational speed creates a new pump curve and operating point.

Velocity – speed.

Velocity Transients - Pressure waves occurring when there is a change in flow rate caused by a change in fluid energy in the line or vessel. Also known as pressure transients.

Vena Contracta - point of lowest pressure is just downstream of the actual orifice at a distance of about half the diameter of the orifice downstream.

Venting (gases) - The release of unburned gas through a vent or flare stack. Also called cold venting.

Vertical Centrifugal Pump - pump's rotating unit is mounted in a vertical position.

Vertical Inline Pumps - single-stage vertical pumps with top-mounted motors. Suction and discharge nozzles arranged so the pump cases can be conveniently fitted into and supported by the piping.

Vibration – three-dimensional motion a machine exhibits from its static state.

Viscometer - instrument that measures the viscosity of a fluid.

Viscosity - measure of a fluid's tendency to resist flow.

Volatility - measure of how easily a liquid will vaporize.

Volume – the space occupied by an object.

W.

w.t. - Abbreviation for pipe wall thickness.

Wafer Check Valve - variety of check valve that has a two-piece disk, hinged down the diameter of the pipe. Flow pushes the valve into the open position. When there is no flow, a spring pushes the disk shut to prevent back flow.

Water Hammer - pressure wave created by the rapid closing of a valve on a flowing line or vessel.

Weight - measure of gravitational force on an object.

Weight Cut - drilling fluid density reduction by entrained fluids.

Wet Gas - gas containing water or condensate vapor.

Weymouth Formula - equation used to calculate flow in line or vessels.

Work - force applied through a distance.

Workover - Remedial work done to the equipment within a well, the well pipe work, or relating to attempts to increase the rate of flow.

X.

Y.

Yielding - The permanent deformation of the steel walls of a line or vessel caused when the MOP is exceeded.

Z.

Z factor – The factor used to compensate for change in density of gas with temperature and pressure not accounted for in the ideal gas law ($PV=nRT$).

Zoning - All equipment should meet API RP 500 for zoning purposes.

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