Well Control Operations

Ballot: 7046

API RECOMMENDED PRACTICE 59
THIRD EDITION, XXX 202X

Introduction

Bop Installations

The recommended practices are separated into two main systems:

1) Surface Blowout Preventers (BOPs),

2) Subsea BOPs.

In this publication, sections have been prepared to establish practices and procedures pertaining to both surface BOP installations and subsea BOP installations. The delineation between surface BOP installations and subsea BOP installations is mainly on an exception basis, and the recommendations made for surface installations apply to subsea installations unless exceptions are stated. The recommended practices can apply to drilling, well service unit, and coiled tubing unit operations. The fundamentals of well flow and well control are the same.

Operations

This standard was developed to provide recommendations on well control planning and procedures to mitigate the risk of an uncontrolled kick. Details of conventional well control methods are presented for both surface and subsea BOP stack installations. Suggested considerations and modifications to conventional well control methods, which may be dictated by well conditions, are also covered. Recommended well control worksheets for surface and subsea BOP installations are included in Annex B. Instructions are included for completing and use of the well control worksheets. Recommended practices set forth in this standard are considered adequate to meet specified well conditions. It is recognized that there are alternate procedures that can be utilized in well control that may be equally as effective in meeting the well requirements and promoting safety and efficiency.

Furthering the Understanding of Well Control

Details of well control technology and reasons for the recommended procedures are included in Section 4, “Principles of Well Control.” Section 4 was prepared so it can be used as a technical base for instructing personnel in well control operations. Annex A contains pressure and pressure gradient calculations as well as examples to emphasize the techniques and calculations that can aid a well control supervisor in understanding well control operations.

Subsea

The International Association of Drilling Contractors (IADC) has published guidelines for planning and drilling deepwater wells, IADC Deepwater Well Control Guidelines

Recommended Practice for Well Control Operations

1 Scope

This standard establishes recommended practices to maintain pressure control of the well during normal operations and when managing a kick. This standard can be used as a technical resource for teaching well control principles. It serves as a companion to API 53, *Well Control Equipment Systems for Drilling Wells* and API 64 *Diverter Equipment Systems*. API 53 establishes requirements for the installation, testing, operation, and maintenance of equipment for the anticipated well conditions, and API 64 establishes requirements for design, installation, testing, and operation of diverters systems.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata).

API

Spec 6A	*Wellhead and Christmas Tree Equipment*
RP 5C1	*Recommended Practice for Care and Use of Casing and Tubing*
RP 5C7	*Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services*
RP 7G	*Drill Stem Design and Operating Limits*
RP 10B	*Recommended Practice for Testing Well Cements*
RP 13D	*Rheology and Hydraulics of Oil-Well Drilling Fluids*
RP 13B-1	*Standard Procedure for Field Testing Water-based Drilling Fluids*
RP 13B-2	*Standard Procedure for Field Testing Oil-based Drilling Fluids*
Spec 16A	*Specification for Drill Through Equipment*
RP 16Q	*Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*
RP 49	*Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide*
STD 53	*Well Control Equipment Systems for Drilling Wells*
STD 64	*Diverter Equipment Systems*
RP 505	*Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities*

ASTM[1]

D-1418	*Practice for Rubber and Rubber Lattices - Nomenclature*

NACE[2]

MR 01-75	*Materials for use in H_2S-containing Environments in Oil and Gas Production*

IADC[3]

IADC Deepwater Well Control Guidelines

3 Terms, Definitions and Acronyms

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1
abnormal pressure
Pore pressure in excess of that pressure resulting from the hydrostatic pressure exerted by a vertical column of water with salinity normal for the geographic area

3.1.2
accumulator
Pressure vessel charged with nitrogen or other inert gas and used to store hydraulic fluid under pressure for operation of BOPs

3.1.3
annular preventer
Device which can seal around any object in the wellbore or upon itself

NOTE Compression of a reinforced elastomer packing element by hydraulic pressure affects the seal.

3.1.4
annulus
Space between the drill string and the inside diameter of the hole being drilled, the last string of casing set in the well, or the marine riser

3.1.5
annulus friction pressure
Circulating pressure loss inherent in the annulus between the drill string and casing or open hole

3.1.6
apparent non-volumetric wellbore behavior
ballooning
breathing
Situations where it appears there is a fluid gain proceeded by a loss of system fluid in the wellbore but are not due to actual changes in the volume of the drilling fluid itself. These situations are often driven by the interaction between the

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[1] ASTM International, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA, 19428-2959, www.astm.org
[2] NACE International, 1440 South Creek Drive, Houston, Texas 77084-4906, www.nace.org
[3] International Association of Drilling Contractors, P.O. Box 4287, Houston, TX 77210-4287, www.iadc.org

wellbore and the surrounding formation or due to multiphase flow dynamics within the wellbore.

3.1.7
backpressure
(casing pressure, choke pressure)
Pressure existing at the surface on the casing side of the drill string/annulus flow system

3.1.8
barite plug
Settled volume of barite particles from a barite slurry placed in the wellbore to seal off a pressured zone.

3.1.9
barite slurry
Mixture of barium sulfate, chemicals, and water.

3.1.10
belching
Slang term to denote flowing by heads

3.1.11
bell nipple
Piece of pipe, with inside diameter equal to or greater than the BOP bore, connected to the top of the BOP or marine riser with a side outlet to direct the drilling fluid returns to the shale shaker or pit and usually has a second side outlet for the fill-up line connection.

3.1.12
bleeding
Controlled release of fluids from a closed and pressured system in order to reduce the pressure

3.1.13
blind rams
Component in a ram blowout preventer that seals the open wellbore.

3.1.14
blind shear rams
Blind rams with a built-in cutting edge that will shear tubulars that may be in the hole, thus allowing the blind rams to seal the hole.

3.1.15
blowout
Uncontrolled flow of well fluids and/ or formation fluids from the wellbore.

3.1.16
blowout preventer
BOP
Device attached to the casing head that allows the well to be sealed to confine the well fluids to the wellbore.

3.1.17
blowout preventer drill
Training procedure to determine that rig crews are completely familiar with correct operating practices to be followed in the use of blowout prevention equipment

3.1.18
blowout preventer operating and control system (closing unit)
Assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the blowout preventer equipment

3.1.19
blowout preventer stack
Assembly of well control equipment including preventers, spools, valves and nipples connected to the top of the wellhead.

3.1.20
borehole pressure
Total pressure exerted in the wellbore by a column of fluid and/or backpressure imposed at the surface at the depth of interest.

3.1.21
bottom-hole pressure
Depending upon the context, either a pressure exerted by a column of fluid contained in the wellbore or the formation pressure at the bottom of the well (i.e., TVD)

3.1.22
broaching
Venting of fluids to the surface or to the seabed through channels external to the casing

3.1.23
bullheading
Term to denote pumping into shut-in well without returns.

3.1.24
casing pressure
See “backpressure”

3.1.25
casing seat test
formation competency test
formation integrity test
Test whereby the formation immediately below the casing shoe is subjected to a pressure equal to the pressure expected to be exerted later by a higher drilling fluid density or by the sum of a higher drilling fluid density and backpressure created by a kick

3.1.26
casing shoe
Component connected to the bottom of a string of casing designed to guide the casing past irregularities in the open hole; usually rounded at the bottom in shape and composed of drillable materials

3.1.27
choke
Device with either a fixed or variable aperture used to control the rate of flow of liquid and/or gas

3.1.28
choke manifold (control manifold)
System of valves, chokes, and piping to control flows from the annulus and regulate pressures in the drill string/annulus

flow system

3.1.29
choke line
High-pressure piping between BOP outlets or wellhead outlets and the choke manifold

3.1.30
choke pressure
See “backpressure”

3.1.31
circulating head
Device attached to the top of drill pipe or tubing to allow pumping into the well.

3.1.32
circulation
The movement of fluids down the interior of a string of pipe in the well and up the annulus

3.1.33
closing unit
Assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the BOP equipment

3.1.34
conductor casing or conductor pipe
(onshore and bottom-supported offshore installations)
Relatively short string of large diameter pipe that is set to keep the top of the hole open and provide a means of returning the upward flowing drilling fluid from the wellbore to the surface drilling fluid system until the first casing string is set in the well

3.1.35
control panel, remote
Panel containing a series of controls that will operate the valves on the control manifold from a remote point

3.1.36
cut drilling fluid
Drilling fluid, which has been reduced in density or unit weight because of entrainment of less dense formation fluids or air

3.1.37
degasser
Vessel, which utilizes pressure reduction and/or inertia to separate entrained gases from the liquid phases

3.1.38
density
The weight of a specific volume of fluid.

Note: The density of drilling and workover fluids is commonly referred to “mud weight” and expressed in pounds per gallon (lbs/gal)

3.1.39
displacement
Volume of steel in the tubulars and devices inserted or withdrawn from the wellbore

3.1.40
diverter
Device attached to the wellhead or marine riser to close the vertical access and direct flow into a line away from the rig

3.1.41
diverter system
Assemblage of an annular sealing device, flow control means, vent system components, and control system which facilitates closure of the upward flow path of the well fluid and opening of the vent to the atmosphere

3.1.42
drill pipe safety valve
full-opening safety valve
A full-opening valve with threads to match the drill pipe connections or other tubulars that is used to close off the drill pipe to prevent flow

3.1.43
drill stem test
DST
Test conducted to determine production flow rate and/or formation pressure prior to completing the well.

3.1.44
drill string float
Check valve in the drill string that will allow fluid to be pumped into the well but will prevent flow from the well through the drill pipe

3.1.45
drilling break
Change in the rate of penetration that may or may not be a result of penetrating a pressured reservoir

3.1.46
drilling spool
Flanged joint placed between the BOP and casing-head or between BOPs that serve as a spacer or crossover

3.1.47
drive pipe
Relatively short string of large diameter pipe usually set in a drilled hole in onshore operations; it is normally washed, driven, or forced into the ground in bottom-supported offshore operations; sometimes referred to as structural pipe

3.1.48
dynamic well kill procedure
Planned operation to control a flowing well by injecting fluid of a sufficient density and at a sufficient rate into the wellbore to effect a kill without completely closing in the well with the surface containment equipment.

3.1.49
equivalent circulating density
ECD
Effects of pressure exerted by hydrostatic head of fluid, drilled solids, and friction pressure losses in the annulus expressed as density

3.1.50
final circulating pressure

Drill string pressure required to circulate at the selected kill-rate adjusted for increase in kill drilling fluid density over the original drilling fluid density; used from the time kill drilling fluid reaches the bottom of the drill string until kill operations are completed or a change in either kill drilling fluid density or kill-rate is affected

3.1.51
formation breakdown
Event occurring when borehole pressure is of magnitude that the exposed formation accepts whole fluid from the borehole

3.1.52
formation competency
formation integrity
Ability of the formation to withstand applied pressure

3.1.53
formation competency test
See “casing seat test”.

3.1.54
formation fracture gradient
Hydrostatic value expressed in psi/ft. that is required to initiate a fracture in a subsurface formation (geologic strata).

3.1.55
formation integrity
See “formation competency”.

3.1.56
formation integrity test
See “casing seat test”.

3.1.57
formation pressure
pore pressure
Pressure exerted by fluids within the pores of the formation (see Pore Pressure).

3.1.58
flow line sensor
Device to monitor rate of fluid flow from the annulus

3.1.59
fracture gradient (frac gradient)
Pressure gradient (psi/ft) at which the formation accepts whole fluid from the wellbore

3.1.60
gas buster
Slang term to denote a mud: gas separator

3.1.61
gas cut drilling fluid
Drilling Fluid that has become entrained with gas from previously drilled gas bearing formation which in turn lowers the drilling fluid density and hydrostatic head of the drilling fluid column

3.1.62
gunk plug
Volume of gunk slurry placed in the wellbore

3.1.63
gunk slurry
Slang term to denote a mixture of diesel oil and bentonite

3.1.64
gunk squeeze
Procedure whereby a gunk slurry is pumped into a subsurface zone

3.1.65
hard close-in
To Close-in a well by closing a BOP with the choke and/or choke line valve closed

3.1.66
hydrogen sulfide
Highly toxic, flammable, corrosive, gas sometimes encountered in hydrocarbon bearing formations

3.1.67
hydrogen sulfide service
Refers to equipment designed to resist corrosion and hydrogen embrittlement caused by exposure to hydrogen sulfide

3.1.68
hydrostatic head
True vertical length of fluid column, normally in feet

3.1.69
hydrostatic pressure
hydrostatic head
Pressure that exists at any point in the wellbore due to the weight of the vertical column of fluid above that point

3.1.70
influx
A quantity of formation fluids present in the wellbore

3.1.71
initial circulating pressure
Drill pipe pressure required to circulate initially at the selected kill-rate while holding casing pressure at the shut-in value; numerically equal to kill-rate circulating pressure plus shut-in drill pipe pressure

3.1.72
inflow performance
IPR
Ability of a well to produce fluids and is typically represented by the curve of a plot of flowing pressure versus flow rate

3.1.73
inside BOP
IBOP
Device that can be installed in the drill string that acts as a check valve allowing drilling fluid to be circulated down the string but prevents back flow

3.1.74
kelly
Uppermost component of the drill string; the kelly is an extra-heavy joint of pipe with flat or fluted sides that is free to move vertically through a "kelly bushing" in the rotary table; the kelly bushing imparts torque to the kelly and thereby the drill string is rotated

3.1.75
kelly cock
Valve immediately above the kelly that can be closed to confine pressures inside the drill string

3.1.76
kelly valve, lower
Essentially full-opening valve installed immediately below the kelly, with outside diameter equal to the tool joint outside diameter

3.1.77
kick
An unplanned, unexpected flow of formation fluids into the wellbore

3.1.78
kill drilling fluid density
Unit weight, e.g., pounds per gallon (lb/gal), selected for the fluid to be used to contain a kicking formation

3.1.79
kill line
High-pressure piping between the pumps and BOP outlets or wellhead outlets

3.1.80
kill-rate
Predetermined fluid circulating rate, expressed in fluid volume per unit time, which is to be used to circulate under kick conditions

NOTE The kill-rate is usually some selected fraction of the circulating rate used while drilling.

3.1.81
kill-rate circulating pressure

Pump pressure required to circulate kill-rate volume under non-kick conditions

3.1.82
leak-off test
Application of pressure by superimposing a surface pressure on a fluid column in order to determine the pressure at which the exposed formation accepts whole fluid

3.1.83
lost circulation
lost returns
Loss of whole drilling fluid to the wellbore

3.1.84
lost returns
See "lost circulation."

3.1.85
lubrication
Alternately pumping a volume of fluid into a closed wellbore system and waiting for the fluid to fall toward the bottom of the well

3.1.86
marine riser system
Extension of the wellbore from the subsea BOP stack to the floating drilling vessel which provides for fluid returns to the drilling vessel, supports the choke, kill, and control lines, guides tools into the well, and serves as a running string for the BOP stack

3.1.87
maximum allowable annular surface pressure
Surface pressure limit calculated from formation integrity/leak-off tests to prevent fracture at the casing shoe (annular pressure limit)

3.1.88
maximum allowable casing pressure
Mechanical pressure rating limit of the casing string itself (based on burst/collapse ratings)

3.1.89
mud-gas separator
Vessel for removing free gas from the fluid returns

3.1.90
normal pressure
Formation pressure equal to the pressure exerted by a vertical column of water with salinity normal for the geographic area

3.1.91
overbalance
Amount by which pressure exerted by the hydrostatic head of fluid in the wellbore exceeds formation pressure

3.1.92
pack-off or stripper
Device with an elastomer packing element that depends on pressure below the packing to effect a seal in the annulus. Used primarily to run or pull pipe under low or moderate pressures

NOTE This device is not dependable for service under high differential pressures.

3.1.93
pipe rams
Rams whose ends are contoured to seal around pipe to close the annular space.

Note: These can include fixed or variable bore type rams

3.1.94
pore pressure
formation pressure
Pressure exerted by the fluids within the pore space of a formation

3.1.95

pressure gradient, normal
Normal pressure divided by true vertical depth

3.1.96
primary well control
Prevention of unintended formation fluid flow by maintaining a pressure equal to or greater than formation pressure

3.1.97
productivity Index
PI
Represents one point on an inflow performance curve (IPR) and is defined as the well flow in barrels per day per psi pressure drop

3.1.98
remotely operated vehicle
ROV
Unmanned vehicle for offshore subsea use

3.1.99
reverse circulation
The movement of fluids down the annulus and up the pipe in the hole

3.1.100
riser margin
The increase in mud weight required for the wellbore below the mud line to be at or over formation pressure once the riser fluid column is removed.

3.1.101
rotating control device
A drill through device with a rotating seal that contacts and seals against the drill string (drill pipe, casing, kelly, etc.) for the purpose of controlling the pressure or fluid flow to surface.

3.1.102
rotating stripper head
Sealing device installed above the BOPs and used to close the annular space about the drill pipe or kelly when pulling or running pipe under pressure

3.1.103
rotary table
Device through which passes the bit and drill string and that transmits rotational action to the kelly

3.1.104
safety factor
Incremental increase in drilling fluid density beyond the drilling fluid density indicated by calculations to be needed to contain a kicking formation

3.1.105
saltwater flow
Influx of formation saltwater into the wellbore

3.1.106
shale shaker

Vibrating screen that removes relatively large size cuttings from the drilling fluid returns

3.1.107
shear rams
BOP rams with a built-in cutting edge that will shear tubulars that may be in the hole.

3.1.108
soft close-in
To Close-in a well by closing a BOP with the choke and choke line valve open, then closing the choke while monitoring the casing pressure gauge for maximum allowable casing pressure

3.1.109

sour gas
Natural gas containing hydrogen sulfide

3.1.110
space-out
Procedure conducted to position a predetermined length of drill pipe above the rotary table so that a tool joint is located above the subsea preventer rams on which drill pipe is to be suspended (hung-off) and so that no tool joint is opposite a set of preventer rams after drill pipe is hung-off

3.1.111
space-out joint
Joint of drill pipe used in hang off operations so that no tool joint is opposite a set of preventer rams

3.1.112
squeezing
Pumping fluid into one side of the drill pipe/annulus flow system with the other side closed to allow no outflow

3.1.113
stripping
Procedure for running or pulling pipe from the wellbore with pressure in the annulus

3.1.114
structural casing
Outer string of large- diameter, heavy-wall pipe installed in wells drilled from floating installations to resist the bending moments imposed by the marine riser and to help support the wellhead installed on the conductor casing

3.1.115
surging
Rapid increase in pressure downhole that occurs when drill stem is lowered too fast or when the mud pump is brought up to speed after starting

3.1.116
swabbing
Lowering of the hydrostatic pressure in the wellbore due to upward movement of tubulars and/or tools

3.1.117
target
Bull plug or blind flange at the end of a tee to prevent erosion at a point where change in flow direction occurs

3.1.118

targeted

Fluid piping system in which flow impinges upon a lead-filled end (target) or a piping tee when fluid transits a change in direction

3.1.119

trip gas

Accumulation of gas, which enters the hole while a trip is made

3.1.120

trip margin

Incremental increase in drilling fluid density to provide an increment of overbalance in order to compensate for effects of swabbing

3.1.121

tubulars

Drill pipe, drill collars, tubing, and casing

3.1.122

underbalance

Amount by which formation pressure exceeds pressure exerted by the hydrostatic head of fluid in the wellbore

3.1.123

underground blowout

Uncontrolled flow of formation fluids from a subsurface zone into a second sub- surface zone

3.1.124

wireline preventers

Preventers installed on top of the well or drill string as a precautionary measure while running wirelines. The preventer packing will close around the wireline

3.2 Acronyms and Abbreviations

For the purposes of this document, the following acronyms apply

ANVWB	apparent non-volumetric wellbore behavior
API	American Petroleum Institute
BOP	blowout preventer
BOPE	blowout preventer equipment
DST	drill stem test
ECD	equivalent circulating density
FIT	formation integrity test
H_2S	hydrogen sulfide
IADC	International Association of Drilling Contractors

IBOP	Inside blow-out preventor
ID	inside diameter
IPR	inflow performance
LOT	leak off test
MAASP	maximum allowable surface pressure
OD	outside diameter
PI	productivity index
ROV	remotely operated vehicle
psi	pounds per square inch

4 Principles of Well Control

4.1 GENERAL

Unplanned formation flow (i.e., a kick) during drilling and well servicing operations can result in a blowout if not properly managed. Well control procedures are intended to safely prevent or handle kicks and reestablish primary well control. This Section discusses common elements and principles of well control. Annex A, Kick Pressure and Gradient Calculations, contains additional discussion and calculations for well pressure gradients and well control. Well control procedures and practices are discussed in other Sections. However, each is based on the basic principles referred to in this Section.

4.2 Conventions

Most of this standard and the examples are written from a drilling operations perspective. The principles and procedures in this standard cover other operations where well control principles and practices are used such as completion, workover, well service, and plug and abandonment.

4.2.1 Design for Specific Rig, Equipment, and Conditions

The drilling, completion, workover, well service, and plug and abandonment operations are done with a wide range of rigs, equipment, and in a variety of conditions. The procedures contained herein are of a general nature and should be reviewed and modified for the specific rig, equipment, and conditions expected in a particular operation.

4.2.2 Drill Pipe/Tubing/Casing

The term “tubulars” can also apply to any string of pipe being run in the hole whether it be drill pipe, drill collars, tubing, casing, a liner, or coiled tubing.

4.2.3 Drilling/Workover Fluid

Unless otherwise noted, the term “drilling fluid” can also apply to “workover” or “completion” fluid. Drilling and workover fluids can be gas, liquid, or foam (refer to 4.5).

4.3 Primary Well Control

Primary well control is the maintenance of pressure in the wellbore that is equal to or greater than the formation pressure to prevent formation flow. Figure 4.1 illustrates an example of primary well control conditions. The drilling fluid column pressure is 5,200 psi at the bottom of a 10,000 ft. column of 10.0 lb/gal drilling fluid; the formation fluid pressure is 4,650 psi. The difference, or overbalance pressure, is 550 psi; therefore, the formation in the well will not flow.

4.4 The Flowing Well

4.4.1 General

Understanding well control requires some background understanding of well flow. A drilling well experiencing a flow from a formation is acting as a producing well. A producing well is a system of interrelated components. The behavior or performance of any one of the components is related to the performance of each of the other components. These relationships determine the rate and volume at which a particular formation in a well will flow. Two relationships require examination: well performance and equipment performance.

4.4.2 Well Performance

Flow rate versus pressure is calculated through the flow path from the bottom of the well to the top. Well performance is independent of the equipment downstream of the point of analysis. The inflow performance relationship (IPR) is the most common well performance relationship. IPR is the flow rate (q) versus pressure at the formation face (refer to Figure 4.2). The more common term, productivity index (PI), is a special case of IPR that applies only to single phase, incompressible flow.

The type of reservoir and reservoir characteristics influence the production rate. Reservoirs can be one of three basic drive mechanisms: water drive, solution gas drive, gas cap expansion drive, or combinations of the three. Flow may be water, gas, oil or combinations of all three. The productivity of a well increases as formation permeability and net pay increase; as productivity increases, so does kick intensity. A high-angle or horizontal wellbore through a section of formation will have more feet of net pay than a vertical wellbore. If permeability is the same in both wells, the one with the most pay has potential for a larger kick. These factors influence the shape of the IPR curves for particular wells. The same is true for the equipment performance curve. The size of the hole, the size of casings, and the size of the tubular goods influence the shape of a particular equipment performance curve.

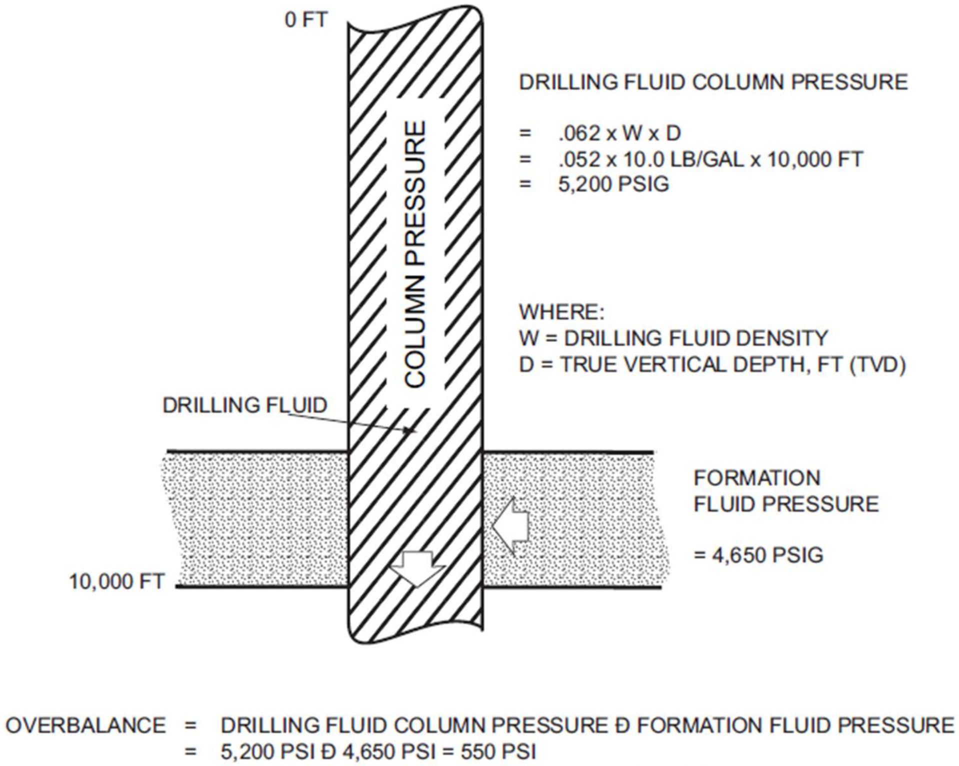


Figure 4.1—Example of Primary Well Control Conditions

4.4.3 Equipment Performance

Flow rate versus pressure is calculated at the point of analysis (refer to Figure 4.3). Every point on the equipment performance curve is valid. However, the only valid value for the well system is at the intersection of the IPR and equipment performance curve (refer to Figure 4.4).

4.4.4 Conditions for Well Flow

If the equipment performance curve for gas/liquid flows in the wellbore does not cross the well performance curve (stays to the right of it in the convention shown in example Figure 4.5), the well will not flow. To kill a well, the equipment performance curve must be designed to exceed the well performance curve. This is called “dynamic kill.” This means the backpressure that can be applied by the hydrostatic head plus the hydraulic friction of the fluids in the annulus must exceed the inflow performance relationship (IPR).

4.4.5 Application of Backpressure to Control Well Flow

Backpressure can be affected by the pump rate, drilling fluid density, and flow restriction in the equipment down-stream of the formation face. These effects should be considered but the choke is used to adjust backpressure during kill operations. Following are three examples:

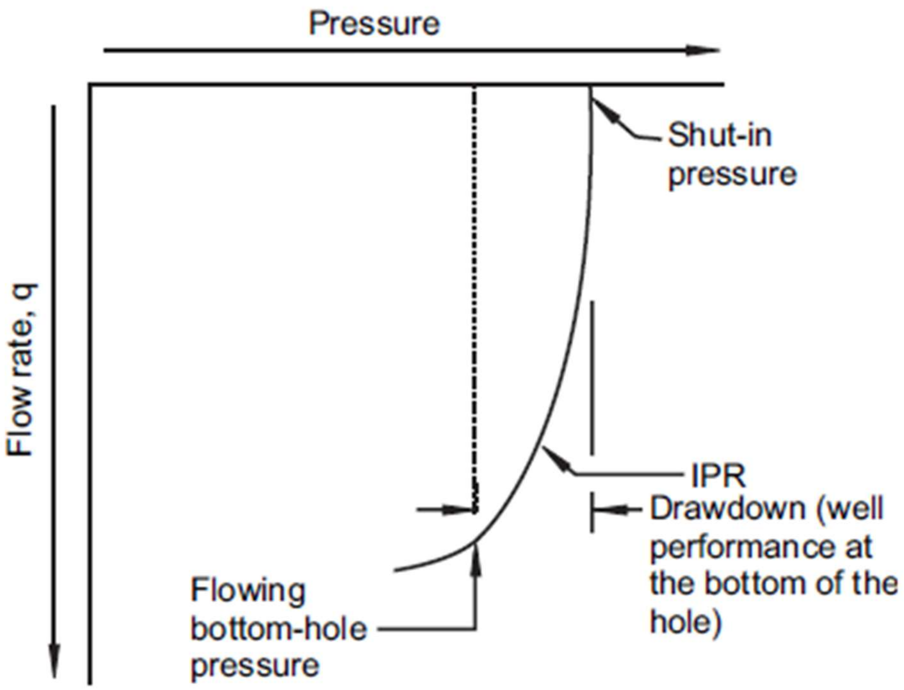


Figure 4.2—Well Performance

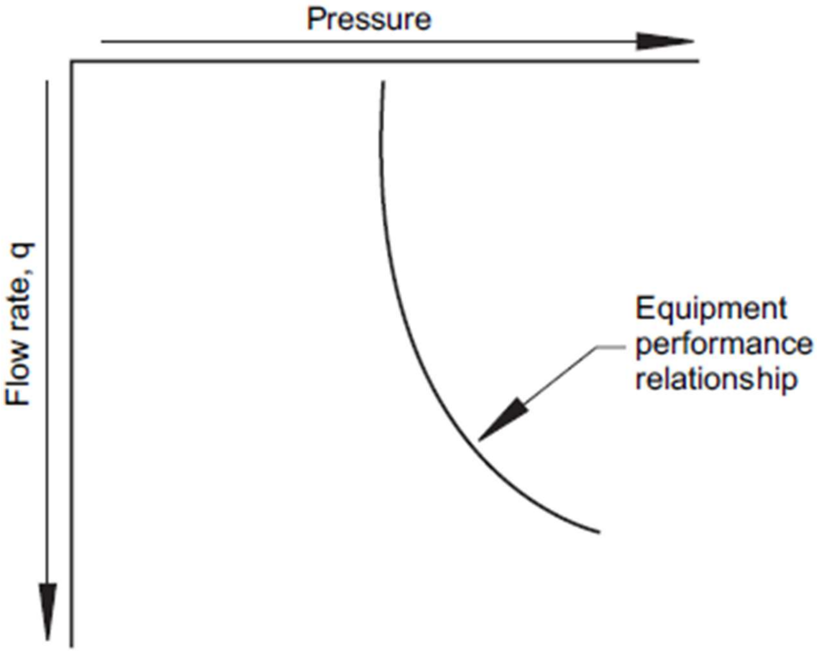


Figure 4.3—Equipment Performance Relationship

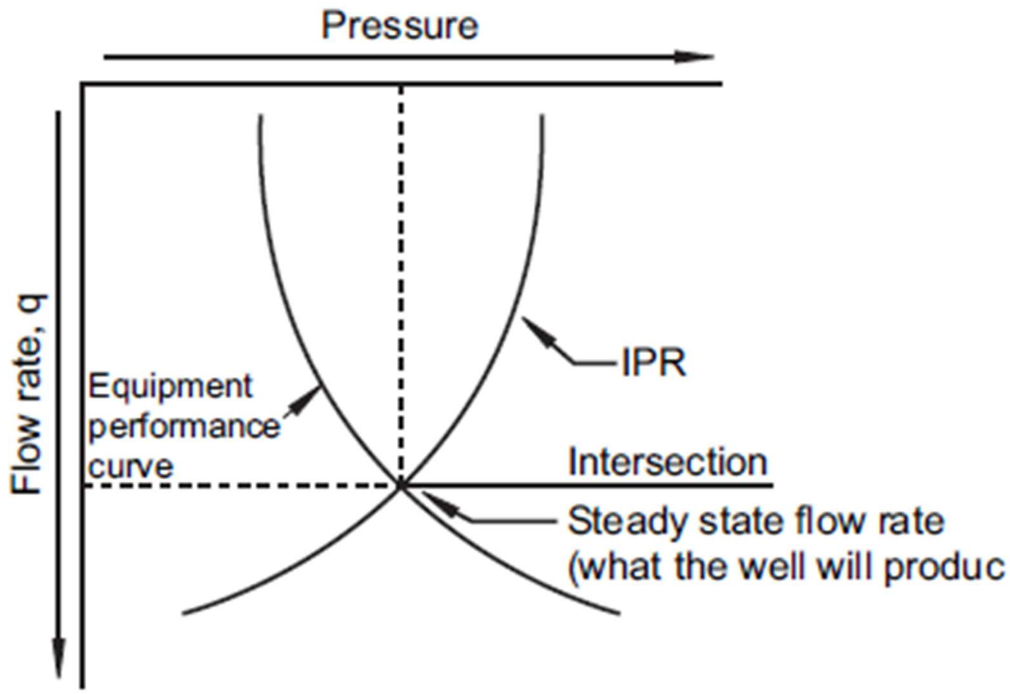


Figure 4.4—Equipment & Well Performance Curves

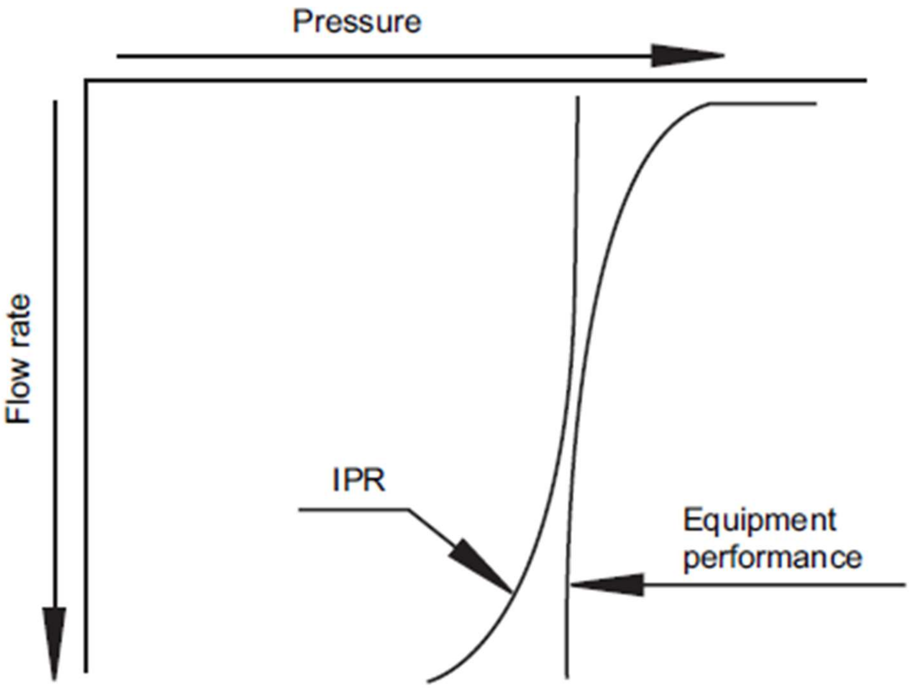


Figure 4.5—Dynamic Kill

1) Pump Rate - Increasing the pump rate results in additional pressure drop, thus more backpressure on the formation.
2) Flow Restriction - When drilling with a BOP, back- pressure can be applied by a surface choke.
3) Fluid Density - If drilling without a riser (circulating mud back to the seafloor), backpressure at the formation face is affected by the hydrostatic pressure of the drilling fluid from the bottom of the hole to the sea floor plus the hydrostatic pressure exerted by the sea.

4.4.6 Well Control Design

A well is usually studied at the discharge (surface) or at the formation (bottom) but may be analyzed at any point in the system. The point selected depends on what is being studied. For example, the diverter may be the point of analysis if the effect of vent line size is being evaluated, the riser may be the point of analysis if the effect of riser size is being evaluated, or the choke line if a deepwater subsea stack is being analyzed.

4.5 Drilling or Workover Fluid

4.5.1 General

Drilling fluid properties are of primary significance in well control. When not circulating, the weight density of the drilling fluid determines the hydrostatic pressure at any point in the static wellbore.

When a well is circulated, the pressure in the wellbore increases due to the resistance of the fluid to flow. The fluid viscosity determines in part the friction of the fluids moving through the pipe, equipment, and hole. This is referred to as ECD and further discussed in section 4.8.5.

Viscosity is a function of the drilling fluid composition as well as the temperature. Drilling fluid composition varies from simple to highly complex. During a kick, the properties of the drilling fluid can be changed due to the influx of formation fluids.

For more information on drilling fluids refer to API RP 13D, *Recommended Practice for Rheology and Hydraulics of Oil-Well Drilling Fluids*; API RP 13B-1, *Recommended Practice for Standard Procedure for Field Testing Water-based Drilling Fluids*; and API RP 13B-2, *Recommended Practice for Standard Procedure for Field Testing Oil-based Drilling Fluids*.

4.5.2 Composition

4.5.2.1 General

There are various types of drilling and workover fluids. The fluid system used varies with the objectives of the well, as well as the temperatures, pressures, and composition of the expected formations. Fluid composition may be changed several times during the drilling and completion of a well. Environmental and government regulation can affect selection of drilling fluid composition.

4.5.2.2 Air, Natural Gas, and Foam

These highly compressible drilling and workover fluids are generally used in areas where low-pressure or highly depleted formations are expected when drilling or conducting remedial cleanout operations. Although these operations are not usually associated with well control problems, well control situations can occur. The hydrostatic pressure exerted by a column of these fluids is small and the fluid density cannot be readily increased. It is important to review field and well history, pressure data, and geology to predict potential problems that might occur and have appropriate contingency plans. In many cases, bullheading (refer to 4.11.1 for bullheading operations) water or other fluid will provide the necessary hydrostatic pressure to regain primary well control.

4.5.2.3 Water-based Fluids

Generally included in this category are freshwater, seawater, produced saltwater, and specialized brine such as calcium chloride and zinc bromide. The desired fluid properties are typically achieved with gels, polymers, inhibitors, weighting material, or combination thereof. Water-based fluids are, for all practical purposes, incompressible and relatively (compared to oil-based fluids) unaffected by expansion due to temperature; the compressibility and temperature expansion factors that exist tend to cancel each other. However, temperature effects should not be ignored when working with water-based fluids. Natural gas solubility in water-based fluids is negligible. These properties provide a relatively stable and predictable fluid density throughout the circulating system and a relatively predictable choke response. Calculated bottom-hole pressures can be predicted with relative certainty. Hydrate formation in cold temperatures can be a concern and is especially so in deepwater. Hydrate formation can be inhibited with glycols and glycerin additives.

4.5.2.4 Oil- and Synthetic-based Fluids

Oil-based fluids can be hydrocarbon and mineral oil based. Synthetic fluids include a number of formulations that simulate the properties of oil-based fluids. Oil and synthetic based fluids can be less dense than water-based fluids; a consideration if less hydrostatic pressure is required to avoid fracturing a formation. However, oil and synthetic based fluids are more sensitive to pressure, temperature, and gas solubility than water-based fluids.

For example:

- Oil and synthetic based fluids are more compressible than water-based fluids and as they compress, they gain density. This effect becomes more pronounced in deep wells and deepwater which can significantly affect both surface and downhole EMW

- Oil and synthetic based fluids are more temperature sensitive than water-based fluids. High temperatures tend to cause thinning and expansion; low temperatures, the opposite. In onshore and shallow water offshore wells, temperature and compressibility tend to balance each other. The temperature effect is most evident in deepwater where the drilling fluid passes from below the mudline to the large diameter riser where the temperatures are typically in the range of 35° to 50°F. Choke and kill lines are similarly affected.

- Natural gas is more soluble in oil and synthetic based fluids than in water-based fluids.

Oil- and Synthetic-based fluids should be confirmed to be compatible with well control equipment elastomers (refer to API 53).

4.6 Influx Behavior

4.6.1 General

Well influx can consist of gas, water, oil, or any combination of these media. Well influx is usually less dense than the drilling fluid and shall be removed from the wellbore.

4.6.2 Gas

Gas is a highly compressible fluid and the volume occupied depends on the temperature and pressure. For example, consider a barrel of gas at the bottom of a 10,000-ft well. The bottom-hole temperature is 170°F and the well is full of 9.0 lb/gal drilling fluid, which provides a hydrostatic pressure of 4,680 psi on the gas. This same barrel of gas will expand to occupy a volume of 280 barrels under atmospheric conditions (assuming 0.6 specific gravity gas at 80°F and 14.7 psia). If that barrel of gas is not allowed to expand in a controlled manner as it is circulated up the wellbore, it will maintain its initial pressure of 4,680 psi as it moves up the annulus and may create excessive wellbore pressures.

Gas is also highly soluble in oil-based and synthetic- or pseudo-oil-based fluids; therefore, special care is required for detecting kicks and handling them with these fluids. Since dissolved gas kicks become an integral part of the liquid phase, these kicks do not behave the same way as free-gas kicks. Specifically, a gas influx which dissolves is more difficult to detect early, and gas breakout can occur rapidly nearer the surface. Solubility depends on factors such as temperature, pressure and fluid composition. For additional information on solubility effects in deepwater operations, refer to the *IADC Deepwater Well Control Guidelines*.

4.6.3 Water

Water is nearly incompressible; it does not expand to any appreciable extent as pressure is reduced. Due to this property, pumping and return rates are equal as a water kick is circulated from the wellbore, provided no further water influx is permitted or fluid is lost. If a water influxes contain some solution gas, surface pressures follow a pattern like that seen during a gas kick.

4.6.4 Oil

Like gas-charged saltwater, oil behaves essentially like a smaller gas influx.

4.7 Formation Tests

4.7.1 General

The pressure at which a formation fractures determines whether the open-hole section can withstand the pressures found in deeper formations. Two tests are designed to yield this information: the leak-off test and the formation integrity test. It is important to have accurate drilling fluid density and pressure data for these tests to yield meaningful results. Use representative samples for measuring the fluid density and use a pressure gauge with the appropriate scale and that has been calibrated.

4.7.2 Leak-off Test

A leak-off test is performed to determine the pressure at which a formation will fracture. Often performed after drilling out the surface casing shoe but can be performed after drilling out subsequent casing shoes of other casings or liner strings to determine the formation leak off pressure at that datum. Normally, 10-15 feet of new formation below the casing seat should be drilled before performing a leak-off test.

Operationally the leak-off test is used to determine how deep the well can be drilled before setting additional casing strings. It provides information on the maximum pressure the wellbore can withstand when shut-in, and the maximum allowable mud weight that may be used.

A leak-off test is typically performed by pumping drilling fluid into the wellbore at a slow rate (typically one-half barrel per minute) with the BOP closed and plotting the resulting pressure versus the total volume pumped. The slow rate enables detection of the leak-off point while mitigating friction effects in the wellbore.

The pressure at which the plotted curve begins to flatten (i.e., when the pressure increases a smaller amount for a volume pumped) is the surface leak-off pressure. At that point, the pump should be stopped immediately to avoid fracturing the formation. This pressure plus the hydrostatic pressure of the drilling fluid is the formation fracture pressure.

4.7.3 Formation Integrity Test

A formation integrity test is performed to a given value less than the estimated leak-off test pressure. The formation integrity test pressure is determined based upon the predicted ECDs required to drill and cement the next section. The test is performed the same way as a leak-off test with the exception that the test is not run until leak-off (i.e., run the test to the target pressure and stop). If the plotted curve begins to flatten or the pressure decreases, pumping should be stopped immediately. Operationally, it is used the same way as the leak-off test.

4.8 Well Control Pressures

4.8.1 General

Well control operations require maintaining bottom hole pressure greater than formation pressure.

A circulating well is more complicated than the static well illustrated in Figure 4.1. This is due to the friction generated by the flow of fluid in the well piping, the open hole, and the inherent resistance of liquids to flow. Pressure must be applied to overcome these forces to circulate a well. Pressure applied at the top of a drilling string alters pressures throughout the pipe and hole. Fluid circulation creates additional overbalance that can help control the well but may also cause excessive pressure that can lead to formation fracture. Several pressure measurements, calculations, and concepts are discussed below with examples to illustrate their significance.

4.8.2 Pressure Measurement

Pressure measurement is a key component of well control. Pressure gauges should be in good working order and calibrated per the recommendations in API 53. Select a gauge with a display range appropriate to the pressure information required. The pressure gauges at the choke panel should be deemed as the primary gauges.

4.8.3 Static Well Pressures

A static wellbore is one in which fluid is not circulating. Figure 4.6 illustrates various pressures in a static wellbore. The drill pipe gauge pressure plus the hydrostatic pressure of the drilling fluid equals the bottom hole pressure. The same pressure balance can be made for the annulus, i.e., surface pressure plus the hydrostatic pressure of the annulus drilling fluid plus the hydrostatic pressure of the influx equals the bottom hole pressure.

4.8.4 Circulating Pressures

Circulating pressures are created while fluid is circulated in the wellbore. The main pressure losses that occur in a circulation system are:

1) Friction loss in the surface piping and connections;

2) Friction losses inside the drill pipe, casing, or work-over string;

3) Pressure drops across the nozzles or water courses in the bit or shoe; and,

4) Friction loss in the annular space between the wellbore and pipe.

The total pressure at the bottom of the hole while circulating is the sum of the combined annular fluid column pressure (hydrostatic head) plus the annular friction pressure plus imposed surface backpressure. The drill pipe circulating pressure is the sum of all friction losses plus corrections due to density imbalances between the drill pipe and the annulus plus any imposed surface backpressure.

4.8.5 Equivalent Circulating Density

The density equivalent of friction pressure in the annulus plus the drilling fluid density in the hole is often expressed as equivalent circulating density (ECD). Figure 4.7 illustrates an example. In this case, the circulating pressure applied to the drill pipe is 2,800 psi. It is largely used to overcome friction of flow through the drill string and bit so that only 200 psi remains to increase pressure in the wellbore at bottom. The additional pressure at bottom is due to the friction loss in the annulus. The annular friction circulating pressure is equivalent to increasing the drilling fluid density by 0.4 lb/gal. No increase in pressure occurs at the top of the annulus when circulating.

For MPD operations, the applied surface backpressure is an additional component of the ECD.

ECDs greater than formation fracture pressure cause loss of mud and well control problems. ECD is relatively high in some operations due to a combination of hole size, drill string OD, measured depth, and mud properties. Some examples are slimhole drilling, some high-angle or horizontal wells, and deepwater wells. When circulation stops in these operations, there may be a significant bottom hole pressure reduction. Therefore, it is important to monitor the well for flow when circulation stops to ensure the well is stable without the ECD effects. Pressure measurement while drilling can be very useful in monitoring ECD. It allows further modeling and calibration of the circulation system.

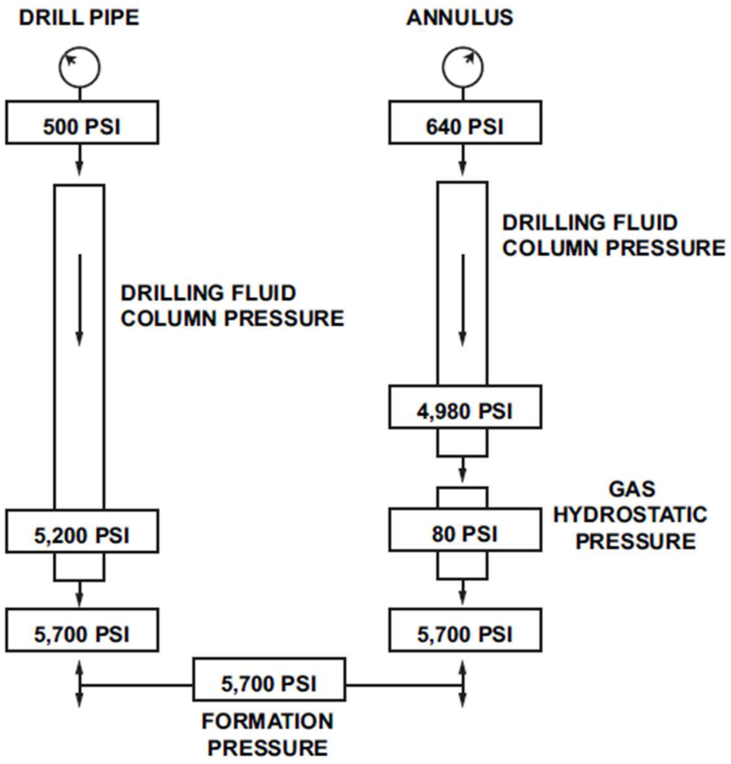


Figure 4.6—Static Well Kick Pressures

4.8.6 Reduced Circulating Pressure or Kill-Rate

For use in well kill planning operations, a circulating pressure is generally measured at a convenient reduced circulating (kill) rate. Kill rates are selected based on the ability of the pumps to pump slow, the ability of the mud mixing equipment to weight up mud, maximum circulation pressures, mud gas separator capacity, choke reaction time, and choke line pressure drop (in the case of subsea wells).

The stroke rate and pressure are typically recorded on the tour sheet for each pump and redone whenever the circulating system pressure is significantly changed (e.g., drilling fluid density, bit nozzles, over 500 ft. of hole is drilled). Alternatively, real-time reduced circulating pressure measurements obtained during a well control event can be used.

Reduced circulating pressures can be used when circulating kicks so that the additional pressure required to prevent formation flow can be added without exceeding system limits (e.g., formation, MGS capacity, mud system capacity, surface equipment ratings). The slower circulating rate also simplifies drilling fluid material mixing procedures and handling returns through the choke.

4.8.7 Initial and Final Circulating Pressures

4.8.7.1 General

An initial and final circulating pressure are used when circulating out kicks. These pressures are a necessity when using the Wait and Weight or Concurrent Weight-up Methods described in 4.10.

4.8.7.2 Initial Circulating Pressure

The initial circulating pressure is the drill pipe pressure after bringing the pumps up to the kill-rate while holding casing pressure constant at the shut-in value. It is also equal to the shut-in drill pipe pressure plus the measured circulating pressure at the selected kill-rate (refer to Figure 4.11).

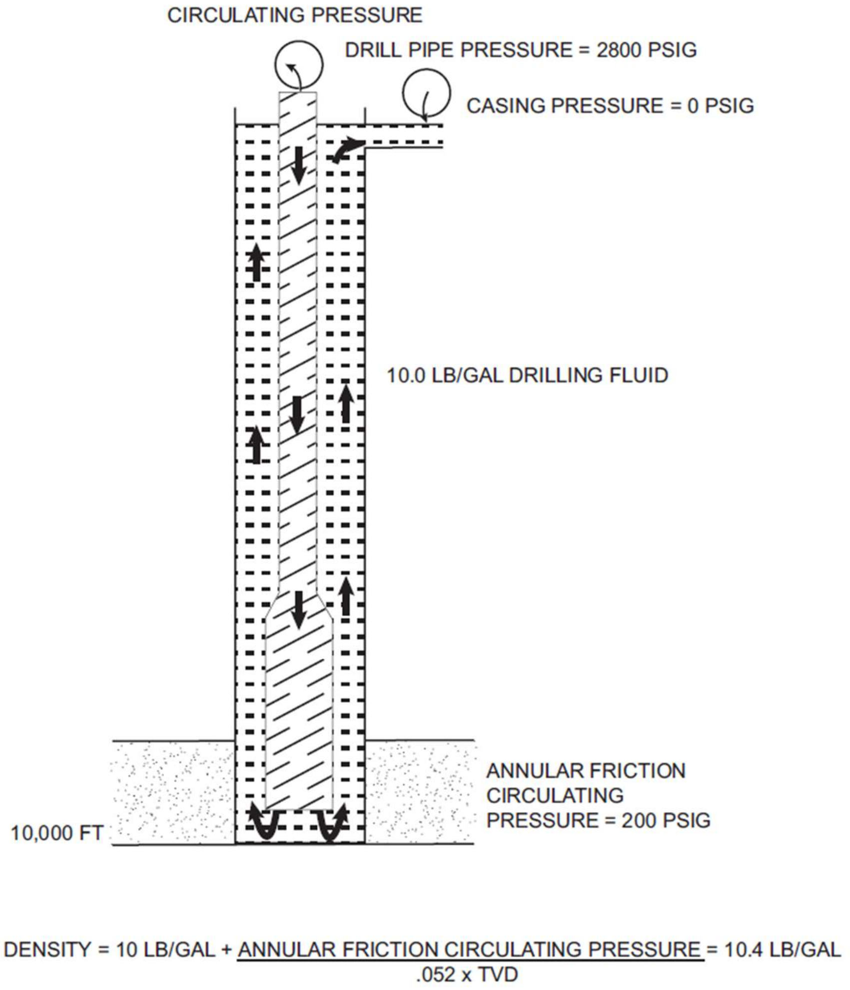


Figure 4.7—Equivalent Circulating Density

4.8.7.3 Final Circulating Pressure

The final circulating pressure is the measured circulating pressure at the selected kill-rate corrected for drilling fluid density increase in the drill pipe.

Example: Figure 4.11 shows that, before the kick, the driller measured 750 psi at a kill-rate of 30 strokes per minute, or 4.5 barrels per minute, using a 10.0 lb/gal drilling fluid. The shut-in drill pipe pressure of 520 psi indicates a required drilling fluid density of 11.0 lb/gal at 10,000 feet.

$$\text{Final Circulating Pressure (psi)} =$$
$$750\text{ psi} \times \frac{11.0\text{ lb/gal}}{10.0\text{ lb/gal}} = 825\text{ psi}$$

4.8.8 Shut-in Drill Pipe and Annulus Pressure

Formation pressure near the wellbore is reduced during flow. When a well is shut-in, the wellbore pressure rises until equal to formation pressure. As the drill pipe and annulus are in communication with the well, the drill pipe pressure will also rise and stabilize.

The stabilized drill pipe pressure indicates the amount to increase the drilling fluid density to balance the formation pressure. The initial stabilized pressures are very important; they are the basis for determining the fluid density required to regain primary well control.

To avoid excess wellbore pressure due to the gas influx migrating up the hole, use a choke to bleed drilling fluid from the casing and maintain the initial shut-in drill pipe pressure. These conditions are illustrated in Figure 4.9. If the well is not circulated, the gas influx will slowly migrate up the hole. During migration the pressure inside the influx will remain the same; however, the wellbore pressure will increase and can lead to formation or casing seat breakdown.

Example: Stabilized Pressures of a Well Shut-in on a Kick–Figure 4.8, is a schematic diagram of a well shut-in on a kick. A 20-barrel gas influx occurs while drilling at 10,000 ft with a 10.0 lb/gal drilling fluid. The stabilized shut-in pressures are 500 psi on the drill pipe and 640 psi on the casing or annulus gauge.

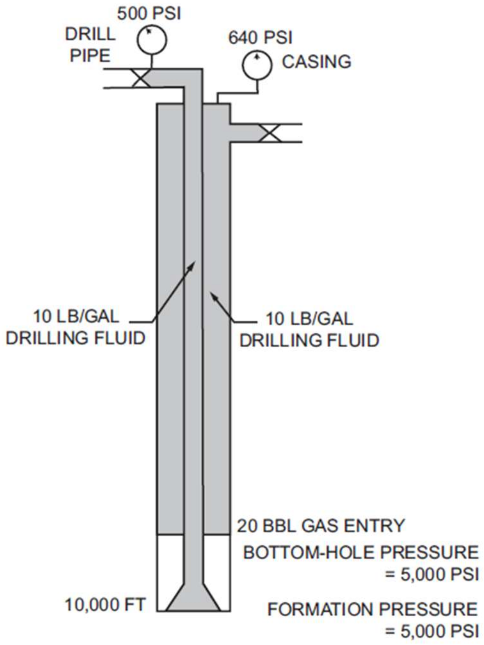


Figure 4.8—Well Shut-in on a Kick

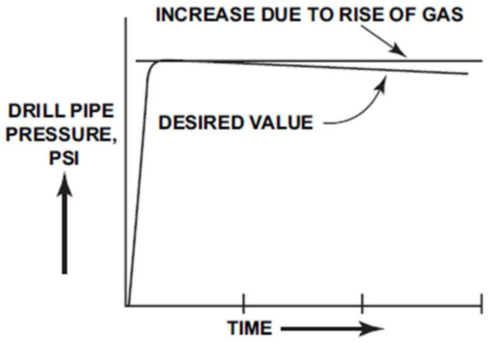


Figure 4.9—Shut-in Drill Pipe Pressure

Example: Shut-in drill pipe Pressure with a Float Valve, to determine the shut-in drill pipe pressure when a float valve is in the drill string, pressure should be increased slowly using the smallest pump available to open the float valve (i.e., bump the float). That resulting pressure is the shut-in drill pipe pressure; however, if casing pressure rises while pumping on the drill pipe, pumping should be stopped and the increase in casing pressure subtracted from the drill pipe pressure to give the shut-in drill pipe pressure (i.e., subtract the erroneous increase from over-pumping).

Example: Gas Influx Migrating Up the Hole–Figure 4.10, illustrates an example of a 10,000 ft shut-in well with 10.0 lb/gal drilling fluid and a small volume of gas at bottom. If a gas bubble is migrating in a wellbore without expanding, the gas pressure will remain constant. When the gas rises to 5,000 ft without expansion or temperature change, the bottom-hole pressure rises to 7,800 psi, which is equivalent to a 15.0 lb/gal drilling fluid column. When the gas reaches the surface, bottom-hole pressure is 10,400 psi, which is equivalent to a 20.0 lb/gal drilling fluid column. At 5,000 ft the borehole pressure is equivalent to a 30.0 lb/gal drilling fluid column to that depth. Such excessive pressure should be avoided whether gas rises through a static drilling fluid column or circulated out by allowing the gas to expand as it rises. The hydrostatic head below the gas column combined with the pressure in the gas column results in a higher bottom-hole pressure. This is not desirable as it can lead to formation or casing seat breakdown.

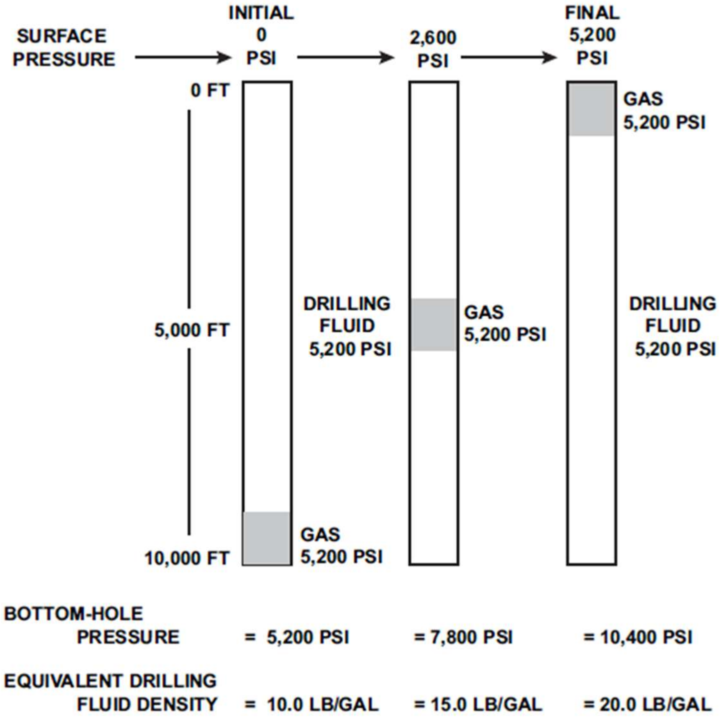


Figure 4.10—Gas Influx Migrating Up the Hole

4.9 Well Close-In Procedures

4.9.1 General

When a kick is detected, the well should be shut-in as quickly as possible to minimize influx volume. There are two shut-in procedure options, the soft shut-in and the hard shut-in. The hard shut-in minimizes kick influx volume, is less complicated, can be performed by one person working on the rig floor, and is usually performed faster than the soft shut-in procedure. If the soft shut-in procedure is contemplated, it should be given consideration in the well pre-planning phase where other mitigations may be identified to remove the need (e.g., higher strength casing, additional casing strings).

4.9.2 Soft Shut-in Procedure

A choke is left open at all times other than during a well control operation. The major disadvantage of the soft shut-in procedure is that the additional time involved in opening the choke line valve and closing the choke allows additional influx into the wellbore. This results in a larger kick volume and potentially higher casing pressure while circulating out the kick thus complicating well control.

Except for one choke line valve located near the BOP, the choke line valves are aligned such that a flow path is open through the choke system. The soft shut-in procedure is:

1) Open the choke line valve.
2) Close the BOP.
3) Close the choke.

4.9.3 Hard Shut-in Procedure

The chokes always remain closed other than during a well control operation. The procedure is simple, allows securing the well in the shortest possible time, and minimizes additional influx into the wellbore. Except for the choke(s) and one choke line valve located near the BOP stack, the choke line valves are aligned such that a flow path is open through the choke system. If the casing pressure cannot be measured at the wellhead, the choke line valve is opened with the choke, or adjacent high-pressure valve, remaining closed so that pressure can be measured at the choke manifold. A hard shut-in is then performed by shutting the BOP.

4.10 Methods for Circulating Kicks at Constant Bottom-Hole Pressure

4.10.1 General

After the well is shut-in, circulation should be established, the kick circulated to the surface at constant bottom-hole pressure to avoid further influx, and drilling fluid density increased to establish primary well control (refer to Section A-1 in Annex A). When circulation can be established, there are two methods of circulating out kicks:

1) Driller's Method - The well is shut-in; then the kick is circulated out without increasing the drilling fluid density; after the kick is circulated out, drilling fluid of required density circulated.
2) Wait and Weight Method - The well is shut-in; the drilling fluid density is increased in the pits as required; then the kick is circulated out with the required density fluid.

4.10.2 Establishing Circulation

The recommended procedure to establish a steady circulating rate while keeping a constant bottom-hole pressure is as follows:

a) Concurrently open the choke and slowly bring the pump up to the pre-selected kill-rate speed.

b) While bringing the pump up to speed, adjust the choke to hold the casing pressure constant at the shut-in value. Holding the casing pressure constant at the shut-in value for the short time required to bring the pump up to speed holds the bottom-hole pressure essentially constant.

c) With the pump running at the desired speed and the casing pressure stabilized at the desired value, read the drill pipe pressure. The drill pipe pressure read at this point is the pressure necessary to maintain a constant bottom-hole pressure if the mud weight and pump rate are held constant. The difference between the shut-in and pumping drill pipe pressure is due to system friction.

d) Determine the sum of the shut-in drill pipe pressure and the pre-recorded kill-rate circulating pressure. If the drill pipe pressure is appreciably different, identify the cause and determine if remedial action is required.

   NOTE Changes in pressure due to choke manipulation require approximately two seconds per 1,000 feet of drill string to register on the standpipe gauge; however, this lag in response time can be longer if a large gas kick is present.

e) If using the Driller's Method, during the first circulation, keep the drill pipe pumping pressure constant by manipulating the choke, while holding a constant pump rate.

f) If using the Wait and Weight method, (or during the second circulation of the Driller's Method), the drilling fluid density in the drill string is increased, the drill pipe pressure will reduce to maintain a constant bottom-hole pressure.

g) Adjustments to the choke will be required for both methods.

Although normally insignificant, annular friction pressure can be viewed as a safety factor to prevent formation fluid flow. This safety factor is equivalent to the amount of the annular circulating pressure.

Additional casing pressure may be applied to provide a larger safety factor. This additional safety factor should be chosen carefully based on ability to manipulate choke pressure to desired values and fracture pressure of the last casing seat. Extra care should be taken with only surface pipe set because shallow formations may break down easily. The well should be killed first then raise the drilling fluid weight to provide the desired overbalance.

When establishing circulation is not possible, practical or desirable, bull-heading or non-circulating methods should be in accordance with 4.11 and lost circulation and underground blowouts should be in accordance with Section 13.

Example: Stabilized Pumping of a Kick—Figure 4.11 illustrates a well just after circulation is initiated. The well was initially shut-in with 520 psi on the drill pipe and 875 psi on the annulus. Circulation was initiated and the choke adjusted to keep 875 psi on the casing while the pump is brought up to the kill-rate of 4.5 barrels per minute (30 strokes per minute). When the kill-rate is reached, a pumping pressure of 1,270 psi on the drill pipe is indicated. The pumping pressure is composed of the kick pressure of 520 psi plus the pressure necessary to overcome the friction losses in the various parts of the circulating system as shown. The friction loss (750 psi) at 30 strokes per minute should have been measured and recorded previously. Since the drill pipe pressure is the same as the sum of the shut-in drill pipe pressure and the kill-rate pressure (520 psi + 750 psi), no adjustment in drill pipe pressure is necessary (refer to 9.6.4). The annular circulating pressure is assumed to be about 50 psi. The bottom-hole pressure is equal to the sum of the casing pressure plus the hydrostatic pressure of the annular fluids plus the annular circulating friction pressure. The bottom-hole pressure is also equal to the drill pipe pressure plus the hydrostatic pressure of the fluid in the drill string less the friction pressure loss in the drill string and bit. The bottom-hole pressure is also equal to the shut-in drill pipe pressure plus the hydrostatic pressure of the fluid in the drill string plus the annular circulating friction pressure loss.

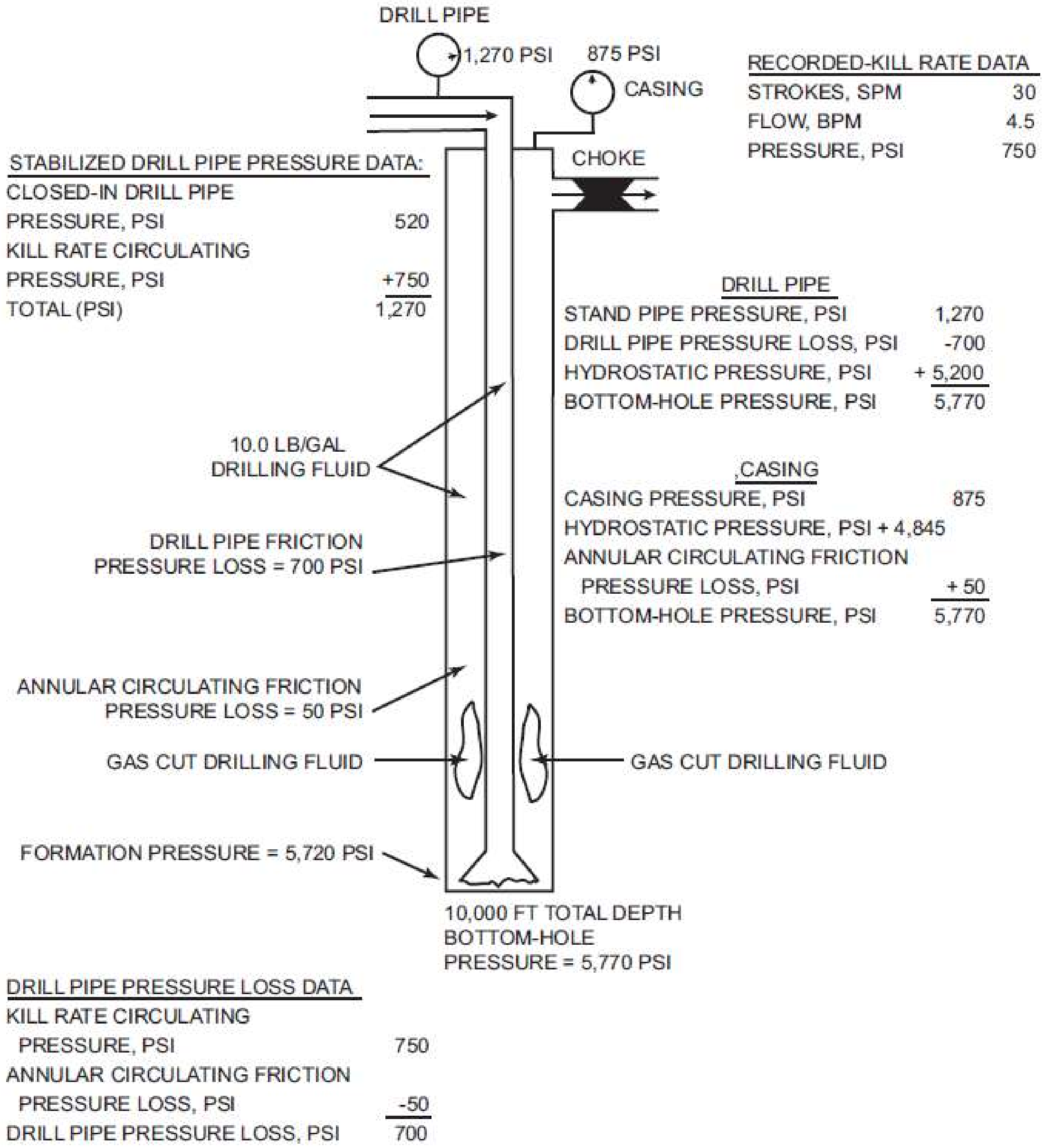


Figure 4.11 — Stabilized Pumping of a Kick

4.10.3 Driller’s Method

The casing pressure required to maintain a constant bottom-hole pressure is dependent on the type of formation fluid and a changing vertical length of formation fluid in the annulus. This change in casing pressure is due to a change in hydrostatic pressure because of influx elongation. Under actual conditions, neither the type nor height of formation fluid is known. Therefore, drill pipe pressure control should always be used to keep constant bottom-hole pressure when circulating kicks out of the annulus. In the drill pipe, drilling fluid density is known and the drill pipe pressure can be read on the gauge. When properly used, these factors determine bottom-hole pressure with relative certainty.

The procedure described for establishing circulation (refer to 4.10.1) results in a desired drill pipe pressure at a constant kill-rate. To circulate a kick at constant bottom-hole pressure without increasing drilling fluid density, circulating rate and drill pipe pressure should be constant. Drill pipe pressure should be held constant by choke manipulation. Circulation can be stopped at any time and the choke closed by keeping casing pressure constant while stopping the pump. Shut-in drill pipe pressure should be the same as when the well was originally closed.

During circulation of the kick, gas expansion and pit volume gain occur. As drilling fluid volume in the annulus decreases due to gas expansion, higher casing pressures will result to maintain constant bottom-hole pressure; but the correct bottom-hole pressure will always result from proper control of drill pipe pressure.

After the kick is circulated out without increasing drilling fluid density, the annulus should be full of drilling fluid. When the well is shut-in, the pressure on the drill pipe and casing should be the same as the original shut-in drill pipe pressure. However, the well is not dead at this point. The well should be shut-in and the drilling fluid density increased in the pits to the required kill density.

Circulation of heavier fluid down the drill pipe at a constant rate will change the circulating drill pipe pressure and eliminate the shut-in drill pipe pressure. The drilling fluid density in the annulus will not change while the heavier fluid is pumped to the bit, therefore to control bottom-hole pressure, maintain constant casing pressure. After the heavier drilling fluid passes the bit, the casing pressure will decrease; but drill pipe pressure will not change and can be used for control. The steps are as follows:

1) Establish circulation at the selected kill-rate as described in 4.10.1. Hold casing pressure constant at the shut-in value by choke manipulation while bringing the pump to speed and thereafter until heavy drilling fluid reaches the bit.
2) When the heavy drilling fluid reaches the bit, read the drill pipe pressure gauge and hold the drill pipe pressure constant at the final circulating pressure and kill-rate by manipulating the choke until the heavy drilling fluid reaches the surface.
3) Shutdown the pump and check for flow.

Example: Driller's Method of Circulating Out a Kick—Figure 4.12 illustrates an example of casing pressure and pit volume increase based on the well conditions shown in Figure 4.11. Initial shut-in drill pipe and casing pressures are 520 psi and 875 psi respectively. When circulation starts, a 50-barrel gas influx is alongside the drill collars and the lower part of the drill pipe. The initial shut-in casing pressure is 875 psi and kick volume is 50 barrels as shown at point A. When 25 barrels of drilling fluid is pumped, the gas bubble is alongside the drill pipe and its total length is shortened in the larger annulus. This produces a longer column of drilling fluid and less casing pressure is required at point B to balance bottom-hole pressure. Gas expansion is slow at first, increasing as it rises in the hole. Maximum casing pressure, gas volume in the hole, and pit gain occur when the gas reaches the surface at point C. Between points C and D, the casing pressure decreases rapidly as gas is being replaced in the well by drilling fluid. Pit volume decreases accordingly. At point D all gas is removed, and casing pressure is the same as the original shut-in drill pipe pressure. Casing pressure and drill pipe pressure are the same because 10.0 lb/gal drilling fluid fills both the drill pipe and annulus. During a kick while drilling, gas flows into the circulating drilling fluid and a mixture occurs. When the well is shut-in, gas migrates up the hole. While circulating the kick, the gas generally rises faster than the drilling fluid. Because the drilling fluid flow rate outside the drill string is not the same at all points across the hole, some gas will be pushed ahead during the circulation, and some will lag. As a result, casing pressures are not exactly as discussed for a single bubble nor are they precisely calculable. Fortunately, the peak casing pressure can be expected to be somewhat less and will occur sooner than dis- placement volume would indicate as shown at point C in Figure 4.13. Due to lag of gas, some additional volume of drilling fluid will be pumped before the well is free of gas as shown in Figure 4.13.

4.10.4 Wait and Weight Method

When the Wait and Weight Method is used, the well is shut-in on the kick, drilling fluid density is increased as required, and the kick is circulated out using the weighted fluid. Circulation is established at the kill-rate as described in 4.10.1. Drill pipe pressure is used to control bottom-hole pressure because of gas expansion in the annulus, but the required drill pipe pressure changes as the pipe fills with the heavy drilling fluid. Drill pipe pressure is maintained by manipulation of the choke.

A schedule of drill pipe pressure change should be prepared and followed. Figure 4.14 shows such a schedule based on the conditions of the 50-barrel kick illustrated in Figures 4.11 and 4.12. Initial circulating pressure is plotted above zero pump strokes, and final circulating pressure is plotted above pump strokes to the bit. A line is drawn between the two points. If a pump stroke counter is not available, the drill pipe pressure reduction schedule can be constructed using either minutes or barrels instead of pump strokes in Figure 4.14. These values are the drill pipe pressures to hold at the strokes, minutes or barrels shown.

In some wells (e.g., deviated wells or internally tapered strings) the line between the ICP and FCP will not be linear. For deviated and horizontal wells, the appropriate kill sheet shall be used.

The final circulating pressure is held until the heavy drilling fluid reaches the surface and the well is dead. Casing pressures and pit volume increases shown in Figure 4.15 are entirely the result of controlling drill pipe pressure. The original shut-in casing pressure is at point A. At point B the gas bubble has been displaced alongside the drill pipe and has shortened in the larger annulus, thus requiring less casing pressure. At point C, the balancing density drilling fluid enters the annulus and begins to reduce the casing pressure.

At point D, the gas begins to expand rapidly, forcing drilling fluid from the hole and increasing casing pressure. At point E, gas reaches the surface. From points E to F, gas escapes and is replaced by drilling fluid, reducing casing pressure. At point F, light drilling fluid in the drill pipe at the time of well closure reaches the surface and the casing pressure continues to drop until the balancing drilling fluid density reaches the surface and casing pressure is zero. Not shown is pit volume increase due to addition of barite.

NOTE: Due to resistance to flow in the choke line and open choke, a small casing pressure can remain when balancing drilling fluid density reaches the surface. The pressure should be less than 100 psi and will bleed off when the pump is stopped.

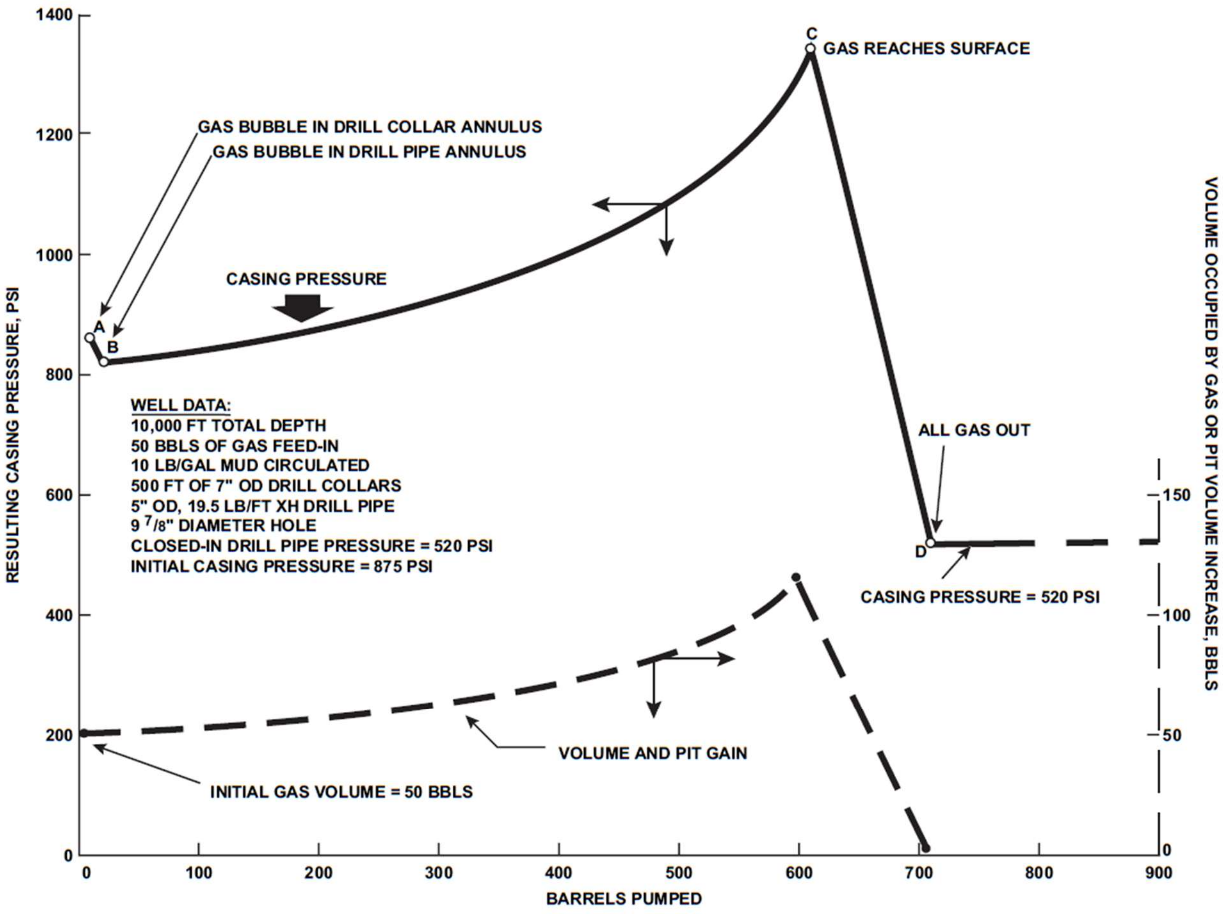


Figure 4.12—Casing Pressure and Gas Volume Resulting from Using the 1st Circulation of the Driller's Method

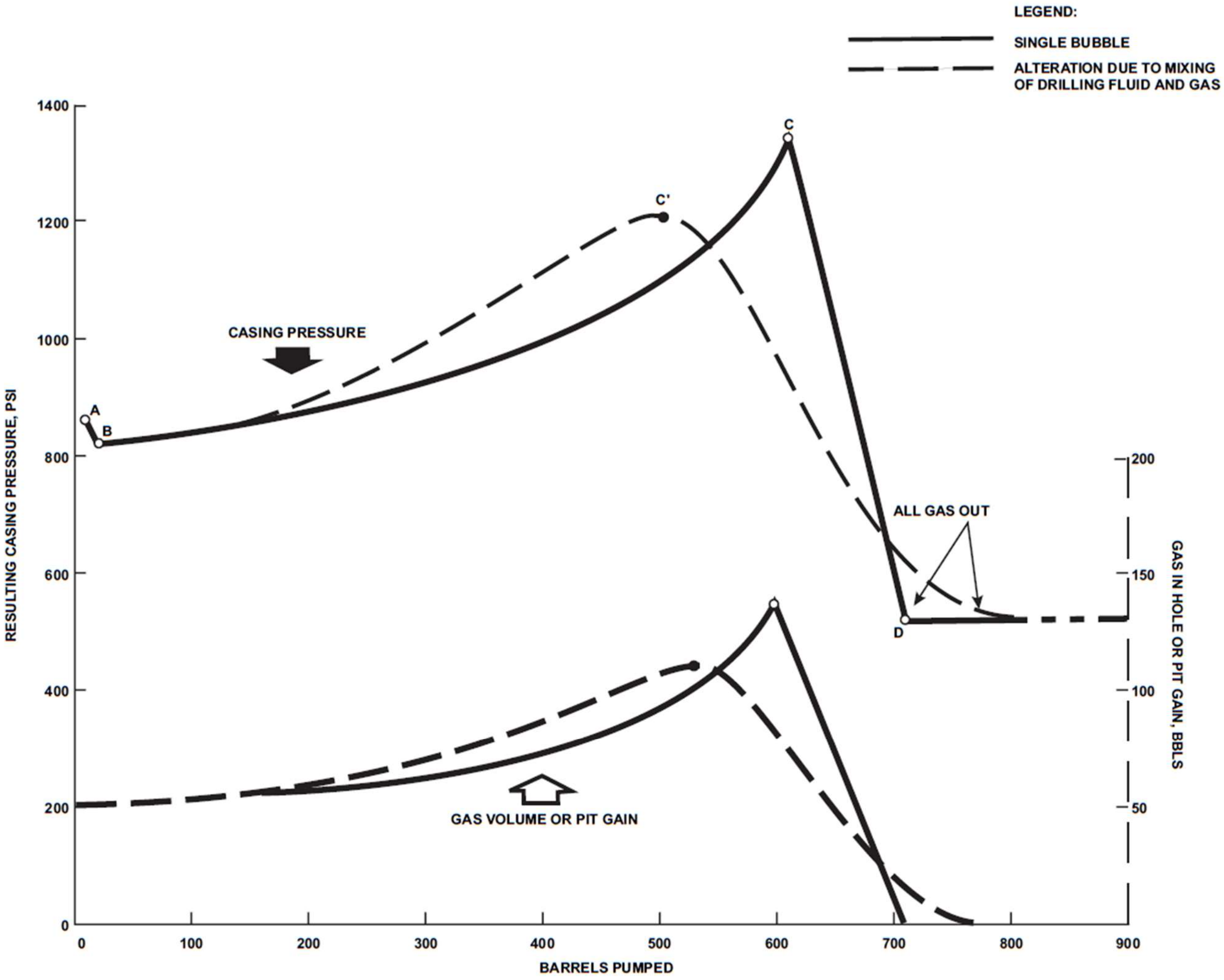


Figure 4.13—Casing Pressure and Gas Volume Using the 1st Circulation of the Driller's Method

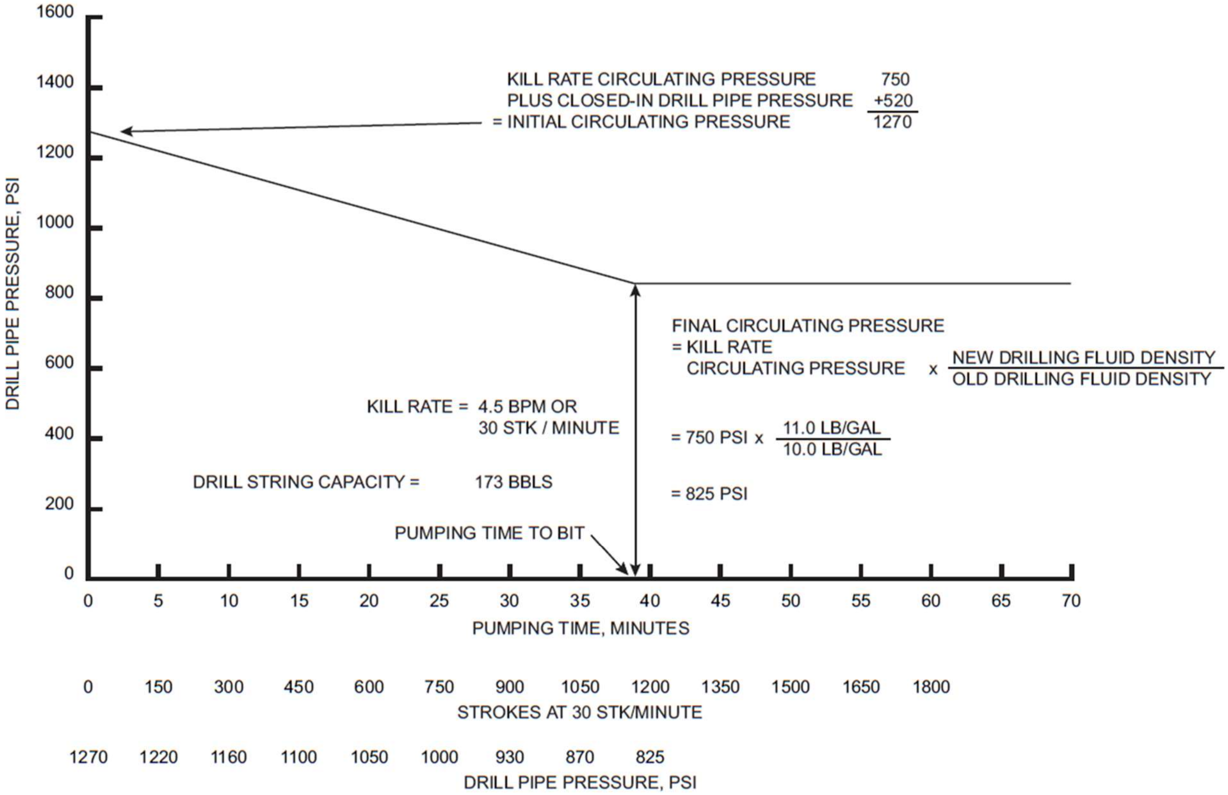


Figure 4.14—Drill Pipe Pressure Schedule for the Wait and Weight Method

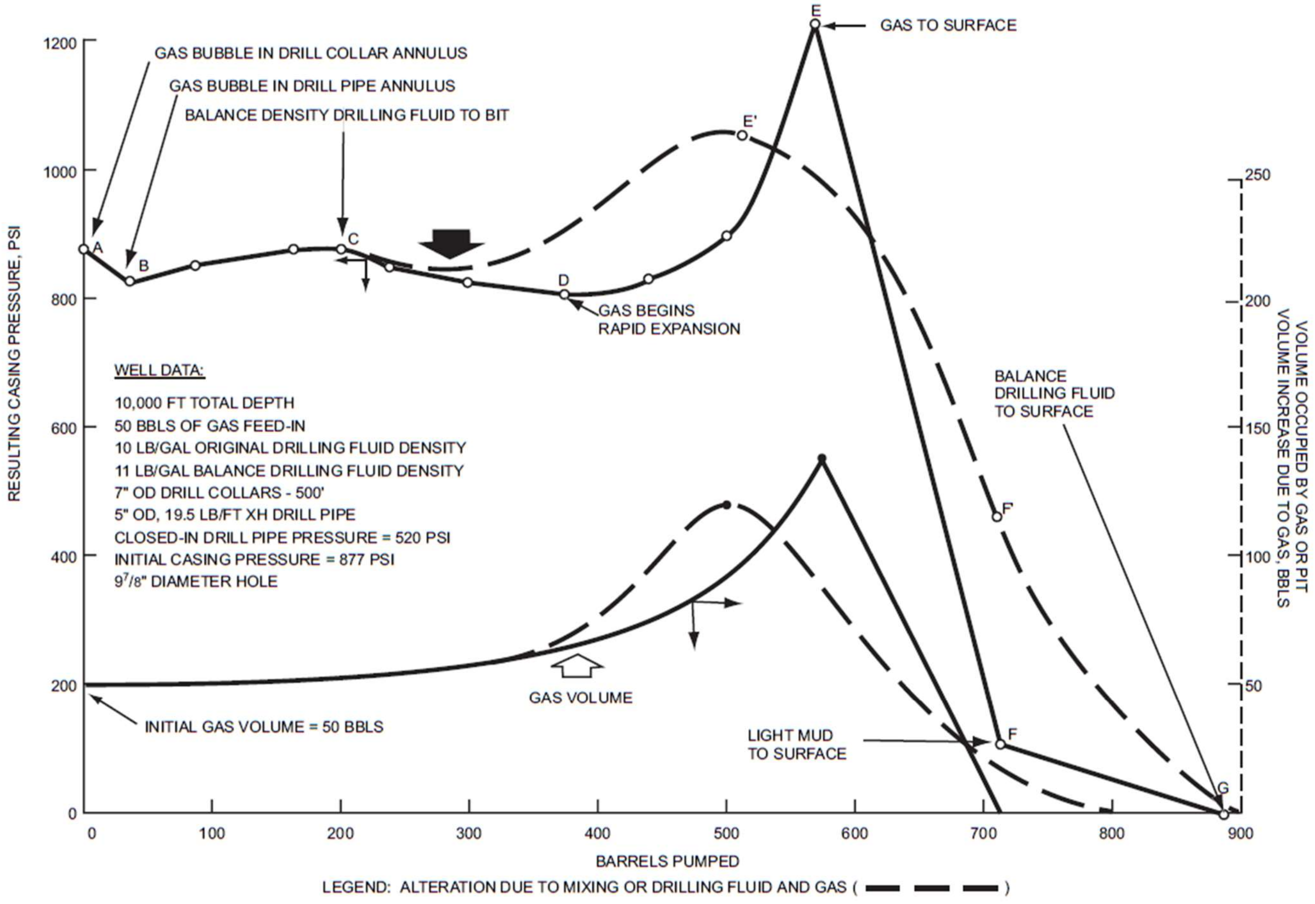


Figure 4.15—Typical Casing Pressure Resulting from Using Wait and Weight Method

4.11 Non-Circulation Kill Methods

4.11.1 Bullheading Operations

Bullheading is continuous pumping of sufficiently dense fluid to kill the well. Bullheading operations are usually employed when anticipated surface pressures are high enough to force the influx fluid back into the reservoir or when the influx contains hydrogen sulfide which cannot safely be handled at the surface. Bullheading is often used in well service operations when circulating is difficult due to a depleted formation.

Bullheading requires surface pressures that can exceed formation fracture pressure. In these instances, wellbore fluids are pumped into the weakest zone exposed in the open hole, which may not be the formation that originally kicked. For these reasons, bullheading is more successful if a long string of protective pipe has been set and the open-hole section is relatively short. Bullheading operations can be used with pipe in or out of the hole and to force lost circulation material into a formation.

4.11.2 Lubricate and Bleed Operations

The lubrication technique is akin to bullheading gently. Instead of forcing continuous fluid into a formation, a fixed volume of kill weight mud is slowly pumped into the kill line where it is allowed to slide downward, increasing the kill mud hydrostatic pressure below the gas. Gas is bled from the surface and the cycle is repeated as conditions allow. Gas at the surface is needed to make lubrication and bleed viable.

Lubricate and bleed reduces surface pressures in a well when gas is at the surface and circulation cannot be established or the pipe is out of the hole. The procedure is as follows:

1) Mix kill fluid of sufficient density to ensure that a minimum volume of kill fluid will be sufficient to reduce the pressures needed for an incremental well kill. Consider using a cement pump for this operation when more accurate volume control is necessary.

2) Plan the increase in casing pressure desired. Pump the mud volume, increasing the well pressure to a pre-determined maximum limit.

3) Allow drilling fluid to settle, then bleed gas until the pressure is reduced an amount equivalent to the hydrostatic pressure of the injected kill fluid.

Bleed dry gas only, do not bleed lubrication fluid.

The following is a method for calculating hydrostatic pressure increase which will reduce surface pressure.

$$Hydrostatic\ Pressure\ Increase = \frac{53.0 \times Kill\ Fluid\ Density\ \left(\frac{lb}{gal}\right) \times Volume\ Injected\ (bbls)}{(Casing\ ID,\ in.)^2 - (Drill\ Pipe\ OD, in.)^2}$$

*Note: If pipe is out the hole, use 0.

Example: For 8 bbl of 12 lb/gal drilling fluid pumped into 9 $^5/_8$-in. 36-lb/ft casing with 4 $^1/_2$-in. drill pipe.

$$Hydrostatic\ Pressure\ Increase = \frac{53.0 \times 12\ \left(\frac{lb}{gal}\right) \times 8\ (bbls)}{(8.921)^2 - (4.5)^2} = 86\ psi$$

4) Repeat this procedure until the situation is resolved.

Note: The injected volume increments will be reduced with time. This can be a very lengthy procedure consuming hours or days. If the pressure cannot be reduced to zero, a snubbing operation can be required.

4.12 Comparison of Kill Methods

Each of the methods has relative advantages and disadvantages. The Driller’s Method is the simplest to handle and to teach, but it requires two circulations and may result in the highest casing pressure as shown in Figure 4.18. This also means that higher casing seat pressure and lost circulation are more likely. The Driller’s Method is preferred for horizontal or highly deviated (i.e., long lateral) wells.

The Wait and Weight Method generally produces the lowest casing seat pressure (often less than initial shut-in pressure) due to assistance of increased drilling fluid density in the annulus while the gas bubble is circulated to the surface. However, this is true only if the drill pipe volume is less than the open hole annulus volume and kill weight mud enters the annulus before the gas bubble reaches the surface. Due to the effect of pressure at the casing seat and associated danger of lost circulation, consideration should be given to use of the Wait and Weight Method, especially if only surface casing is set.

Other considerations of the Driller’s versus Wait and Weight Methods are time on the BOPs, availability of weighting material, ability to mix mud and circulate, hydrates, gas migration rate (function of hole angle, influx type, drilling fluid type), and hole type (e.g., vertical, horizontal, or highly deviated).

The Concurrent Method theoretically has the least danger of stuck pipe, as there is less time with pressure on the well and less time with an uncirculated kick; however, it is not a constant bottom hole pressure method. For the Concurrent Method, casing pressures are intermediate to the other well kill methods and is the most complicated to run due to rig equipment and personnel limitations related to the ability to mix mud reliably for the duration of the kill, and unknown bottom hole pressure at any point in time. For these reasons the Concurrent Method is not recommended or further discussed.

Bullheading and other Non-circulating Methods are for special situations where circulation is impractical or high surface pressure needs to be reduced, or it is undesirable to bring well fluids to the surface, as described in 4.11.1 and 4.11.2.

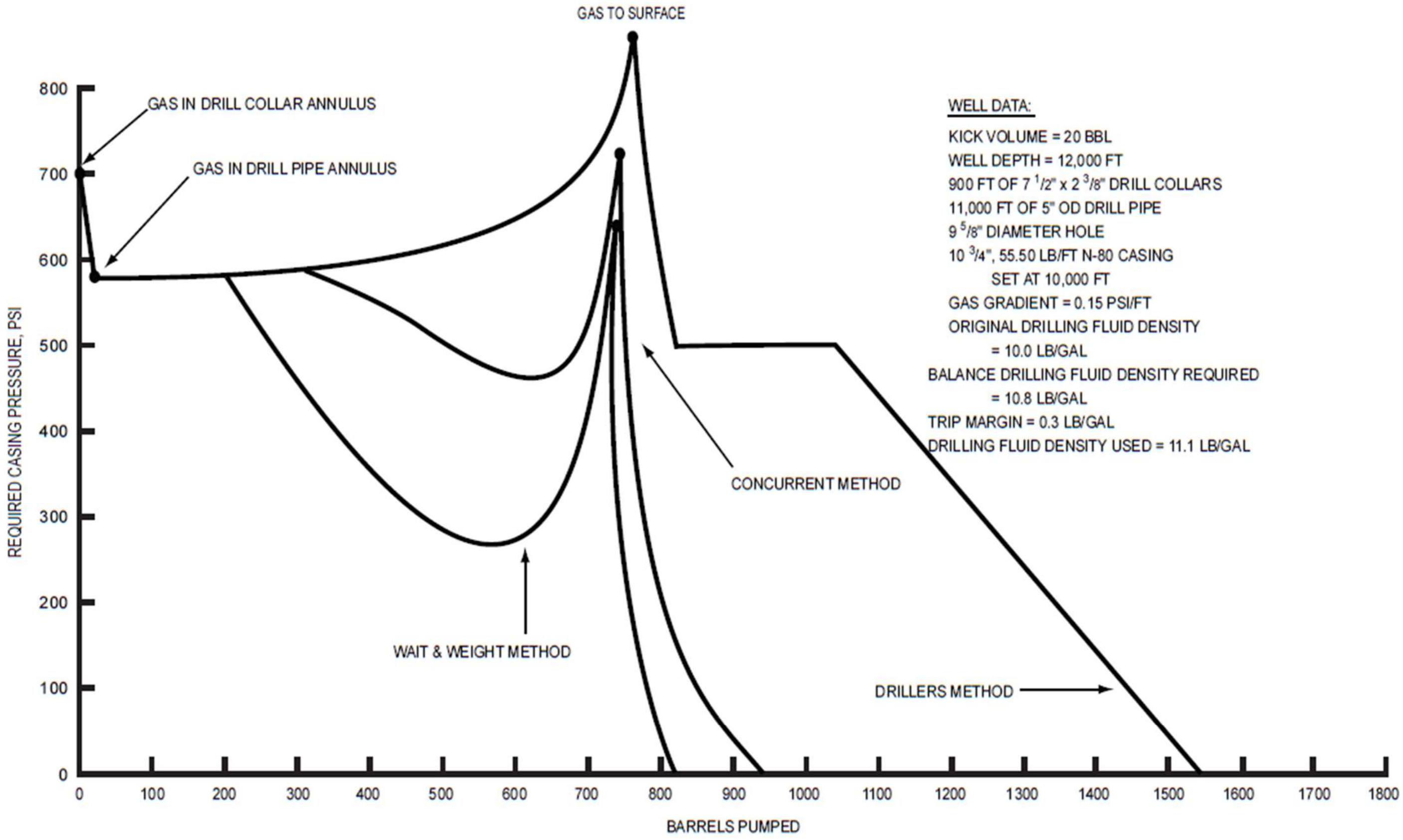


Figure 4.18—Example of Approximate Casing Pressures with Different Kill Methods

4.13 Choke Line Pressure—Subsea Stacks

4.13.1 General

When handling kicks in deepwater, flow resistance (i.e., choke line friction) in the choke line from the BOP stack to the surface plus the manifold and open choke is higher than on a surface BOP. Unless kill-rates are low and the choke line pressure properly taken into account during well kill operations, excess pressures in the well bore can increase the risk of lost circulation.

4.13.2 Measurement of Subsea Choke Line Pressures

The choke line pressure at any one rate is the drill pipe circulating pressure with BOPs closed and the choke line and choke fully open, minus the drill pipe circulating pressure with BOPs open.

If the initial drill pipe circulating pressure can be established at the correct value, there can be some period in the well killing operation where the choke is wide open but the drill pipe circulating pressure is greater than desired by the amount of the choke line pressure. Therefore, a graph should be prepared showing choke line pressure at various flow rates so that a kill-rate can be selected that has a choke line pressure less than anticipated shut-in casing pressure and so that the excess pressure in the well due to choke flow line resistance can be evaluated. The procedure is as follows:

1) Before drilling out surface casing, determine and record the drill pipe circulating pressure through the drill string, choke line, and open choke using a closed BOP and at the predetermined SCR.

2) Determine and record kill-rate circulating pressure for at the same three SCRs as in step 1 with BOPs open.
3) Subtract values obtained in Step 2 from those obtained in Step 1. This value is the CLF at the current mud density.

Using two flow lines, i.e., choke and kill lines, reduces the choke flow line pressure by a factor of approximately four (4). Therefore, if the rig can use both lines to the choke, the procedure should be repeated using both lines in step 1 and determining a kill and choke line pressure.

4.13.3 Direct Measurement of Choke Line Pressure Losses

Choke line pressure losses can be measured directly by pumping into the choke manifold, down the choke line or choke and kill lines into the open BOP stack, and up the riser. The pressure shown on the choke manifold gauge is the choke line pressure loss (CLF) (or if using both choke and kill lines, the combined line loss is shown). Any errors caused by small circulatory pressure losses in the riser are negligible. Choke line pressure loss measurements should be taken whenever drilling fluid properties are significantly changed (e.g., going from seawater to mud, increasing drilling fluid density).

4.13.4 Handling Subsea Choke Line Pressures During Kicks

The kill line or wellhead pressure gauge/sensor can be used to monitor casing pressure when circulation is begun after a kick. The kill line or wellhead pressure should be visible at the surface and the kill line pressure or wellhead pressure held constant by adjustment of the choke while bringing the pump up to speed. The kill line should also be opened to monitor pressure during any changes in circulation rate.

If it is not possible to utilize the kill line pressure, the choke pressure should be allowed to drop an amount equal to the choke line pressure losses while bringing the pump(s) up to speed. Otherwise, the drill pipe pressure will be too high as will bottom-hole pressure and pressure at the casing seat. Even when correct drill pipe pressure is established there can be a time near the end of the kick kill operation when the choke will be wide open and the drill pipe pressure can build to a value higher than desired by the amount of the choke line pressure loss.

4.13.5 Kill-rate Selection with Subsea Stacks

Experience has shown that low formation breakdown pressures are expected in deeper water. As water depth increases, the seawater head plus the soil overburden pressure is less than the total soil overburden pressure at the same depth for a land or shallow water location (water density is less than rock density). Due to the high friction loss in the relatively long choke line used with subsea stacks, it is necessary to circulate out a kick at a rate to avoid formation breakdown.

After a string of casing has been set and if formation breakdown pressure is known, the maximum choke manifold pressure that can be shut-in without causing formation breakdown is the MAASP.

The calculated allowable pressure loss in the cased hole and choke system, shall be used in conjunction with measured slow circulating pressure (SCP) data to determine the appropriate kill-rate selection. SCP values, which are routinely established during daily operations for the active drilling fluid, provide the relationship between circulation rate and system pressure losses required for application of the Driller’s Method or Wait and Weight Method.

By comparing SCP values obtained at predefined reduced circulation rates (e.g., 50 gpm [~10 spm], 100 gpm [~20 spm], and 150 gpm [~30 spm], etc.) with the allowable pressure loss, the maximum kill rate may be selected as the highest reduced circulation rate for which the measured pressure loss does not exceed the formation breakdown limit.

4.14 Diverter Systems Applications

The recommendations in this section distinguish clearly between surface stack installations and subsea stack installations. Diverter system philosophy, operational objectives, and recommended pump operation differ significantly between these two configurations.

Guidance applicable to surface stack installations shall not be assumed applicable to subsea stack installations, where gas in the riser is addressed as a riser management hazard with applicable riser gas handling procedures.

4.14.1 Surface Stack Installations

At shallow depths where drive pipe, conductor pipe, and structural casing are set, fracture gradients are very low, and wells sometimes cannot be shut-in on a kick without danger of lost circulation possibly broaching to the surface. Controlling these shallow gas flows can be difficult as these formations can be abnormally pressured and gas expands rapidly as it rises to the surface. Furthermore, drilling these shallow gas sands can rapidly gas-cut the drilling fluid to the extent that expansion during flow to the surface lowers the hydrostatic pressure enough to cause formation flow.

In addition, dispersal of drilled cuttings in the drilling fluid can cause the drilling fluid density to increase to a point where circulation may be lost, causing the hydrostatic head to drop thereby allowing the well to flow. In these situations, a diverter can be used to direct well flow away from the rig during kicks.

The diverter shall be arranged so that a diverter line automatically opens or is open when the diverter is closed to divert the fluids and prevent inadvertent well shut-in.

Flow shall be diverted from the rig to a safe area downwind and results in loss of drilling fluid from the system. Under these conditions, formation fluid flow continues during the well control operation until the hole bridges or hydrostatic pressure can be built enough to regain primary control and stop formation fluid flow. Pumping at a fast rate with heavy fluids is a method for controlling a shallow gas kick. Alternatively, the rig can be evacuated.

Refer to 8.3 for more information on diverter operations and Section 13 for mixing heavy fluids.

4.14.2 Subsea Stack Installations

For subsea stack installations, diverter systems are not intended to function as a primary well control device when the well can be isolated by closing the subsea BOP. In these cases, gas in the riser represents a riser management hazard rather than a well control event, and operational response should follow the guidance for gas in the riser.

When gas is suspected or confirmed in the riser above a closed subsea BOP, circulation and pressure management should be conducted using dedicated riser gas handling methods, where available, rather than relying on conventional diverter operations. For rigs equipped with Managed Pressure Drilling (MPD) or Riser Gas Handling (RGH) systems, these systems can provide controlled flow paths and/or pressure management capabilities within design limits that significantly reduce risks associated with unrestricted diversion.

In subsea stack applications, diverter systems shall be considered a secondary HSE barrier, intended primarily to:

a) protect the rig floor from unintended releases, and
b) provide a contingency flow path in abnormal or emergency conditions, and
c) prevent inadvertent well shut-in.

Surface diverter overboard lines should be preselected to divert flow away from the rig to a safe area downwind.

Diversion with pumps running is not recommended for subsea stack installations when the well is isolated and riser gas handling or MPD capabilities are available, as uncontrolled diversion may increase risks associated with excessive outflow, surface equipment overload, and gas dispersion. Pump operation during riser gas events should instead be governed by the selected riser gas handling procedure and the capacity limits of the surface handling equipment.

4.15 Well Control Worksheets

Refer to IADC guidelines for well control worksheets.

5 Causes of Kicks

5.1 Conditions Necessary for a Kick

Two conditions in the wellbore are required for a kick to occur:

— The pressure at the face of the kicking formation must be greater than the pressure in the wellbore; and

— The kicking formation must have sufficient permeability to allow flow into the wellbore.

Loss of primary well control is usually due to:

— Failure to keep the hole full;

— Swabbing;

— Insufficient drilling fluid density;

— Insufficient combination of hydrostatic head plus backpressure (e.g., MPD operations)

— Lost circulation; or

— Combination thereof.

These problems can occur during any operation conducted on a well.

5.2 Insufficient Hydrostatic Pressure

5.2.1 General

Two primary causes of well kicks are insufficient fluid density and insufficient fluid level in the wellbore, especially while tripping.

5.2.2 Insufficient Density

This can be caused by:

1) Higher than anticipated pore pressures or,

2) The drilling or workover fluid becomes contaminated by less dense fluids or formation gas.

5.2.3 Hole Not Full of Adequate Density Fluid

When the fluid level in the wellbore is allowed to drop the resulting reduced hydrostatic pressure can become less than the formation pressure and allow formation fluid entry into the wellbore.

5.2.4 Tripping Out of the Hole

5.2.4.1 General

When pipe is pulled from a well, a reduction of bottom hole hydrostatic pressure will occur. Two causes of lower hydrostatic pressure are:

— failure to fill the hole to correct for the volume displacement of the pipe and,

— swabbing

5.2.4.2 Drilling and Completion Operations

In operations where circulation is desirable, such as most drilling or completion operations, the displacement volume of the pipe being pulled from the hole should be replaced to keep the hole full and maintain constant hydrostatic pressure. The displacement volume should include at a minimum the BHA, drill string attachments, tapered drill strings, and slug volume changes.

If the hole fails to take the proper amount of drilling fluid, hoisting operations should be suspended and a preplanned safe course of action executed while monitoring the well. This can require returning to bottom and circulating the hole. The frequency of filling the hole during tripping operations is critical; the hole should be completely filled at intervals that prevent an influx of formation fluid. Continuous filling or filling after each stand of drill pipe may be advisable. The hole should be filled after each stand of drill collars. When the hole is filled continuously, an isolated drilling fluid volume measurement facility (such as a trip tank) shall be used.

5.2.4.3 Well Service Operations

In operations where circulation is not normally maintained, as during well service operations where wells with depleted formations are being worked over, consideration should be given to keeping a volume of fluid in reserve to add or bullhead into the well as needed to maintain control. A common practice is to continuously lubricate fluid with enough density to maintain well control.

5.2.4.4 Swabbing

Bottom-hole pressure reduction occurs when swabbing takes place and is one of the major reasons for losing primary well control. Swabbing can be difficult to detect. Formation fluid may enter the wellbore as the pipe is withdrawn and results in the wellbore taking less than the expected fill volume. Detection of an influx due to swabbing can be determined by measuring the drilling fluid added to the hole as pipe is pulled. Trip tanks or an equivalent is commonly used to accurately measure the fluid addition.

Three prime factors in controlling swabbing are:

a) Drilling fluid properties;

b) Rate of pulling pipe; and

c) Drill string and hole configurations

5.2.5 Tripping In the Hole

When running pipe in the hole, the drilling fluid volume increase at the surface should be equal to the calculated pipe volume displacement. Highly permeable and weak formations can be susceptible to fluid loss or fracture if pipe or tools are run in the hole too fast, causing pressure surges which can lead to lost circulation.

5.2.6 Lost Circulation

Lost circulation can result in the loss of well overbalance that constitutes primary control. The loss can result from natural or induced causes. Natural causes include fractured, vugular, cavernous, subnormal-pressure, or pressure-depleted formations. Induced losses can result from mechanical formation fracturing resulting from:

a) Excessive drilling fluid density,

b) Excessive ECD,

c) Pressure surges related to running pipe or tools,

d) Excessive pressure resulting from breaking circulation, or

e) Packing-off in the annulus.

Casing leaks or downhole plug failures can also cause lost circulation (refer to section 13.2).

5.2.7 Excessive Drilling Rate Through Gas Sand

Even if the drilling fluid density in the hole is sufficient to control formation pressure, gas from the drilled cuttings will mix with drilling fluid. The composition of the drilling fluid can influence the amount of mixing (refer to section 4.5). A high ROP through a shallow gas zone or coal bed can supply enough gas from the cuttings to reduce the hydrostatic pressure of the drilling fluid column. The hydrostatic pressure loss can reach the point where the formation begins flowing into the wellbore. In deeper wells a similar effect can occur through a progressive combination of drilling fluid density reduction resulting in “belching” drilling fluid out of the hole without the well flowing.

5.2.8 Drill Stem Testing

A drill stem test (DST) is performed by setting a packer above the formation to be tested and allowing the formation to flow. During testing, the wellbore or casing below the packer and at least a portion of the drill pipe or tubing is filled with formation fluid. Depending on the length of hole below the packer, type of fluid entry, and formation pressure, the normal drilling overbalance can be reduced or lost. At the conclusion of the test, the fluid in the test string above the circulating valve shall be removed by established well control techniques, such as reverse circulation, to return the well to a safe condition.

Note: Swabbing can occur when pulling the test string due to the larger diameter packers.

5.3 Drilling into an Adjacent Well

Many directional wells can be drilled from the same offshore platform or onshore drilling pad. If a drilling well accidentally penetrates the production string of an existing well, the formation fluid from the existing well can enter the wellbore of the drilling well or the drilling fluid of the well being drilled can be lost to the penetrated wellbore; either of which can lead to a kick.

6 Well Control Warning Signals

6.1 Well Control Information Sources

Information that can indicate a possible well control issue can be classified into the following categories:

a) Previous Field History and Drilling Experiences
    1) Depth of zones capable of flowing
    2) Formation gradients
    3) Fracture gradients
    4) Formation content
    5) Formation permeability
    6) Intervals of lost circulation
b) Physical Response from the Well (well monitoring indicators)
    1) Pit gain or loss
    2) Increase in drilling fluid return rate
    3) Flow after the pumps are stopped
    4) Changes in flow line temperature
    5) Drilling breaks

    6) Variations in pump speed or standpipe pressure
    7) Swabbing
    8) Drilling fluid density reduction
    9) Effects of connections, short trip, and trip on shows and gains
    10) Hole problems indicating underbalance (i.e., tight hole, packing-off, sloughing)
    11) Excessive pressure or pressure changes between casing strings
    12) Cuttings size, shape, and quantity
- c) Chemical and Other Technical Responses from the Well
    - 1) Chloride changes in the drilling fluid
    - 2) Oil show
    - 3) Gas show (chromatograph)
    - 4) Formation water
    - 5) Shale density
    - 6) Electric logs
    - 7) Drilling equation exponents
- d) Nearby well operations
    - a) Fracking
    - b) Injection wells

6.2 Primary Kick Indicators

6.2.1 General

Primary kick indicators shall be treated as a kick and the well shut-in until confirmed otherwise.

6.2.2 Gain in Pit Volume

An unaccounted volume gain in the drilling fluid pit(s) is an indication that a kick may be occurring. As the formation fluid feeds into the wellbore, it causes more drilling fluid to flow from the annulus than is pumped down the drill string, thus the volume of fluid in the pit(s) increases.

6.2.3 Increased Flow from Annulus

If the pumping rate is held constant, the flow from the annulus should be constant. If the annulus flow increases without a corresponding change in the pump rate, the additional flow is caused by formation fluid(s) feeding into the wellbore or gas expansion.

6.2.4 Flow after Pumps Stopped

This can be due to several causes including an underbalanced formation kick, thermal expansion of the drilling fluid, rig heave, or Apparent Non-Volumetric Wellbore Behavior (ANVWB). If flow continues, excluding normal drain back, after the pumps are stopped, the well shall be shut-in and evaluated to determine subsequent actions (refer to section 6.4 Well Monitoring and Fingerprinting).

6.2.5 Volume of Drilling Fluid to Keep the Hole Full on a Trip

Formation fluid entering the wellbore will result in the recorded trip volume being less than the calculated trip sheet value. As soon as the fluid discrepancy is detected, tripping operations shall be stopped and a flow check conducted.

If a kick is detected (well flowing), the well shall be shut-in, drill string stripped to bottom, and killed using a well control method.

If the well was swabbed (well not flowing), the drill string should be run back to bottom (or well shut-in and stripped to bottom depending on size of influx), the well shall be shut-in, and influx removed using the driller’s method.

NOTE: When the drill string is run back to bottom with well not shut-in the influx will be elongated which will reduce bottom hole pressure and can result in the well flowing.

6.3 Secondary Kick Indicators

6.3.1 Sudden Increase in Bit Penetration Rate

A sudden change in penetration rate (i.e., drilling break) is usually caused by a change in the type of formation being drilled; however, it may also signal an increase in formation pore pressure. If a sudden change is detected, the well should be drilled 5-10 feet and then flow checked.

NOTE: In wells with high geologic uncertainty (i.e., wildcat/exploratory wells), circulating bottoms-up is often performed to give more insights into the reason for the sudden change in penetration rate.

6.3.2 Change in Pump Speed or Pressure

If a change in pump speed or pressure is detected the well should be flow checked.

NOTE: Change in pump speed or pressure can also be caused by mechanical pump issues.

The initial surface indication that a well kick has occurred can be a momentary increase in pump pressure. The pump pressure increase is seldom recognized because of its short duration, but it has been noted on some pump pressure recording charts after a kick was detected. The pressure increase is followed by a gradual decrease in pump pressure and can be accompanied by an increase in pump speed. As the lighter formation fluid flows into the wellbore, the hydrostatic pressure exerted by the annular column of fluid decreases, and the drilling fluid in the drill pipe tends to U-tube into the annulus. When this occurs, the pump pressure will drop, and the pump speed will increase.

NOTE: Modern drilling rig control software can mask these indicators.

The lower pump pressure and increase in pump speed are also indicative of a washout (i.e., hole in the drill string). Until confirmation can be made as to whether the cause is a washout or a well kick, a kick should be assumed.

6.3.3 Gas-Cut Drilling Fluid

6.3.3.1 General

Gas-cut drilling fluid often occurs during drilling operations and can be considered one of the early warning signs of a potential well kick; however, it is not a definite indication that a kick has occurred or is impending. An essential part of analyzing this signal is being able to determine the downhole conditions causing the drilling fluid to be gas-cut. Gas-cut fluid occurs due to one or more of the following downhole conditions:

- Drilled Gas;
- Trip Gas;
- Connection Gas; and
- Flow from Gas Zone.

6.3.3.2 Drilled Gas

When the hydrostatic pressure exerted by the drilling fluid is greater than the pore pressure of a gas-bearing formation being drilled, there is no influx of gas from the formation. Nevertheless, gas from the drilled cuttings when present will mix with the drilling fluid causing the returns to be gas-cut.

As gas is circulated up the annulus, it expands slowly until just before reaching the surface. The gas then undergoes a rapid expansion, resulting in the drilling fluid density being reduced and a small hydrostatic pressure reduction. This reduction in density is not necessarily an indicator that a kick is about occur because drilling fluid of correct density is still maintained in most of the hole.

6.3.3.3 Trip Gas

After circulating “bottoms-up” following a trip, a higher level of gas entrained in the drilling fluid returns may cause a short duration density reduction or gas unit increase. This condition can be caused by various mechanisms (e.g., swabbing, incorrect hole fill, gravity segregation, ANVWB). These symptoms can indicate increasing formation pressure when compared with previous trips.

6.3.3.4 Connection Gas

After circulating “bottoms-up” following a connection, a higher level of gas entrained in the drilling fluid returns may cause a short duration density reduction or gas unit increase. This condition can be caused by various mechanisms (e.g., reduced BHP due to pumps stopped / lost ECD). These symptoms can indicate increasing formation pressure when compared with previous connections.

6.3.3.5 Flow from Gas Zone

Influx from a gas zone while drilling is a kick and the well shall be shut-in. While drilling, the formation pore pressure must exceed the hydrostatic pressure of the drilling fluid plus the circulating friction losses in the annulus for gas from the formation to flow into the wellbore. Once influx begins, continued circulation without the proper control of surface pressures will induce additional flow, since the density of the hydrostatic column (annulus) is continually reduced by the flow of formation fluid and expansion of gas.

6.3.4 Liquid-Cut Drilling Fluid

When a permeable liquid-bearing formation having pore pressure greater than the drilling fluid hydrostatic pressure is encountered, fluid will feed into the wellbore. Depending upon the pressure differential between the formation and the drilling fluid, the influx can be detected by:

- A gain in pit volume;
- Lower density returns;
- A change in drilling fluid chlorides;
- A change in temperature; and
- An increase in torque.

6.4 Well Monitoring and Fingerprinting

6.4.1 Introduction and Purpose

Well monitoring is the process of observing all drilling activities and analyzing the data trends. Fingerprinting is observation of drilling trends using modern equipment and analysis methods. A perfectly volumetric well will exhibit constant stable circulation with no gains or losses while drilling. Such wells should still be monitored and even fingerprinted if for no other reason than to gain operational command over the techniques of fingerprinting. This section provides guidance with respect to Apparent Non-Volumetric Well Behavior (ANVWB), also sometimes called, supercharging, ballooning, or breathing. HTHP wells are often susceptible to ANVWB phenomena due to narrow gaps between formation pore pressure and fracture gradient. Non-HPHT wells can also manifest ANVWB.

Apparent Non-Volumetric Well Behavior (ANVWB) features finite, measurable “losses of mud to the formation” when pumps are turned on, followed by the return-to-surface of substantially all the “lost” mud when the pumps are turned off. The mud is apparently “lost” due to either ECD-induced fractures or induced pore space storage and/or, previously-existing micro fractures or pore space. Unlike a true constant lost-circulation situation, the formation is temporarily “storing” the finite mud volume which will be returned to the surface upon cessation of circulation. The common, but misleading, term for this phenomenon is “ballooning.” The wellbore is not actually “flexing” or changing volume itself. Mud is simply being “stored” temporarily in some kind of connected reservoir system adjacent to the wellbore itself. Drill string surging and swabbing can cause or exacerbate ANVWB. If ANVWB is present, the “loss to formation” while drilling always precedes the “gain to rig” while the pumps are shut off.

6.4.2 Well Control Concerns

ANVWB raises two immediate concerns. The first is losses which initially demonstrate the symptoms of true lost circulation. The second is the return of stored drilling mud, which initially demonstrates the symptoms of a formation fluid influx (kick) into the wellbore. The first line of defense in both phases of ANVWB (loss and gain phases) is to fingerprint the well. Any pumps-on losses should be described in terms of the pump parameters and return-to-surface flow patterns with particular attention paid to the pressure, volume, and rate of losses versus time. Any pumps-off returns should be similarly described with particular attention paid to return flow volumes, rates, and pressures versus time.

Accurate fingerprinting might be impossible due to irregular loss/gain and fluctuating pressures. Erratic pressure and loss/gain situations indicate crossflow due to an underground blowout (UGBO). Pressures and volumes in an UGBO are so erratic that tertiary well control methods should be used.

The most common crossflow begins with a kick from a deep high-pressured zone. When the well is shut in, shallower zone(s) fracture, causing fluid to flow upward into fresh fractures between the kick zone at well TD and open zones below the last casing.

There are theoretical ways to use tertiary well control all of which are both difficult and potentially dangerous, beginning with “simple” tasks. Constant pressure fluctuations prevent accurate determination of downhole pressure and required kill weight. Flowrate and velocity of kick fluid might have to be a guess. Depth of thief zone(s) are probably available if LWD is in the drill string. Define all the pressure weaknesses of the drill string, mud pumps, and mud mixing system.

Overpowering an UGBO might be feasible using a dynamic kill in which high volumes of heavy mud is injected into the well. Also possible is an “IN/OUT” method like PMCD. In that case, LCM is pumped down the annulus while kill weight mud (if known) is pumped down the drill pipe. Finally, it may be possible to use various slurry combinations of diesel oil, barite, and cement.

The result of this ANVWB will have the same initial indications as a kick, flow from the well with pumps off or flow out greater than flow in when at a reduced pump rate. As the result is an indicator of a WCE, the conventional response is to shut in the well using the BOP. Alternatively, if Managed Pressure Drilling is being used and procedures and permissions are in place to use MPD for well control purposes, the MPD well control procedures can be used to arrest the flow.

Once the well is secure, and initial diagnostics determine that ANVWB is a possible reason for the flow there are two initial options to address resolution. The well can be circulated using the driller’s method to evaluate constituents of what flowed into the well. Alternately, conducting the volumetric bleed technique can be done to confirm if the source of the flow was ANVWB or a kick. The general procedure below describes the volumetric bleed technique. While executing the volumetric bleed, once ANVWB has been identified, the well can be circulated after bleeding back an agreed total bleed volume the well can be circulated routing BU through the MGS. All subsequent BU, including once well has returned to static unless prior BU has indicated the absence of gas.

Initial parameters to investigate for ANVWB

- Mud losses greater than seepage have occurred
- Shut-in casing pressure is less than annular friction pressure

- Shut-in casing pressure less than or equal to shut in drill pipe pressure
- Volume gain prior to shut-in less than total volume lost

Post shut in diagnostics – volumetric bleed technique

- Bleed flow path should be as direct to a trip tank or stripping tank as possible.

  Note: Bleeds through the MGS will prevent accurate volume control and result in confusion.
- Record the following info:
  - Total loss volume
  - Cumulative loss volume
  - Shut-in Drill Pipe Pressure (SIDPP)
  - Shut-in Casing Pressure (SICP)
- Initial bleed step
  - Open choke to pre-determined position
  - Bleed 5-10 bbls
  - Close choke (assure no leakage)
  - Record and document
    - Initial SIDPP/ISICP (HPHT/WH/BOP pressure if available)
    - Bleed duration
    - Post bleed stabilized SIDPP/SICP
    - Time to stabilize
- If stabilized post bleed pressures are higher than initial, the event is Well Control and a drillers method circulation should be conducted
- If Stabilized post bleed pressures have decreased, prepare for another bleed step
- Additional bleed step:
  - Open choke to pre-determined position use for initial step
  - Bleed 5-10 bbls
  - Close choke (assure no leakage)
  - Record and document
    - Initial SIDPP/ISICP (HPHT/WH/BOP pressure if available)

- Bleed duration
- Post bleed stabilized SIDPP/SICP
- Time to stabilize

To define the event as ANVWB, the stabilized pressure after each bleed will continue to decrease and the durations for the bleed / build will increase. If this is true, bleeding should continue until the well becomes static. If the initial choke position is not open enough to allow for adequate flow (pressures becoming low and flow back rate slow, the choke position can be adjusted to a larger open position. This should be documented as it will prevent use of the time duration of that bleed from being a monitorable indicator for the current bleed step, however, stabilized pressure reduction will apply.

6.4.3 Fingerprinting Procedure to Identify ANVWB

The activities necessary to identify ANVWB are as follows:

- Begin fingerprinting inside a casing shoe prior to drilling out. Start pumps to impose ECD (annular friction pressure) on wellbore in addition to mud hydrostatic density (ESD). The compressibility of the drilling mud can also be determined. The annular friction pressure is significant. Document and log any mud loss to the formation while drilling out.
- After drilling out, if losses are noted, the first sign of ANVWB is a decreasing trend of losses as the formation fractures fill up. An increasing trend of returns at the surface while circulating or drilling might also demonstrate fracture fill up. When the hole stops taking fluid, the induced storage capacity of the formation is reached and the circulation pattern can become normal with no more losses.
- Turn pump off and drain back the ECD, leaving ESD which will not keep the fractures full of mud.
- Drain back and log the mud previously lost to the formation. Given that ANVWB might be suspected from previously turning on the pump as described in the first step above, the drain back should exhibit decreasing trends of volume and pressure, provided no influx is also occurring. The volume of mud pumped into "storage" should be virtually identical with the volume that returns to the rig with the pumps off. When in doubt about drain back, perform a hard shut in and use the Driller's method to circulate the suspected influx to surface.
- It is imperative to keep accurate logs of the amount of mud lost to the formation and subsequently gained back. Both the Driller and Mud Logger should keep logs. Accurate records are the key to successfully managing ANVWB. The chart of mud loss with pumps on, should overlay previous charts. Similarly, the pumps-off charts should overlay with each other.
- The difficulty with ANVWB is discriminating between the mud coming back and a genuine kick. Unless it is certain that only the lost mud is being returned, the gain when the pump is turned off must be treated as an influx.
- It is desirable to avoid ANVWB by keeping the wellbore pressure (ECD) less than the ANVWB propagation pressure, assuming that pressure is known.

6.4.4 Procedures for Handling Mud Flow Back in ANVWB Wells

Drain back is the volume of mud that flows out the top of the well when the pump is turned off. To reduce the risk associated with rogue flow back (i.e., an influx), the following procedure can be used:

- The first-time flow back is encountered, consider it a real kick. The mitigating circumstance is that a previously fingerprinted mud "loss" upon starting the pumps defines an expectation for the drain back to expect with the pumps turned off.

- The driller’s method should be used so that the influx can be analyzed before the mud weight is raised.

- The rate of drain back into the wellbore should be closely monitored. ANVWB should result in a steady or declining rate of drain back. If the rate of drain back is increasing, the well should be shut-in immediately and the influx circulated out as a kick.

- Fluid shall not be bled from the well without first consulting the Toolpusher who should supervise the bleed-off operations. If consistent drain back is occurring, more specific rules can be made as to what volumes of fluid can be bled off without specific authorization from the Operations Manager. It is essential that all operations be carried out consistently. The OIM and Toolpusher should be responsible for ensuring that sufficient information is relayed to the Driller.

6.4.5 Drilling Ahead After Identification of ANVWB

When ANVWB is identified, the hole section being drilled has not reached section TD. Once losses have been identified, the current open hole section being drilled has no kick tolerance. Drilling under these conditions requires risk assessment with input from subsurface, drilling engineers, rig supervision and a WC SME. The risk assessment should evaluate the likelihood of encountering a flowable formation of higher pore pressure and determine whether the risk can be mitigated. The primary risks of associated with continued drilling are the potential loss of reliable well monitoring and the possibility of encountering a higher-pressure zone, which could result in an underground blowout and subsequent broaching to surface.

Understanding the mechanism of the losses should be evaluated to determine if the opportunity exists to artificially strengthen the wellbore using loss circulation material.

From a well monitoring perspective, this task becomes more complex when both losses and gains take place while being unable to artificially strengthen the loss zone. Under these conditions, personnel responsible for well monitoring must be able to distinguish between flowback associated with ANVWB and flow resulting from a kick. This requires establishing a revised baseline flowback after drilling a joint or stand down and stopping pumps to make a connection. Connection monitoring is no longer focused on confirming drain back to a "no flow" condition. Instead, it is focused on assessing flow back signature / fingerprinting based on the losses experienced.

Based on the risk assessment outcome, if drilling ahead is deemed feasible, the engineering and operations team shall develop a well monitoring plan that accounts for ANVWB. This plan shall define the expected flow back volumes at pre-determined points during connections to verify flowback rates remain consistent with baseline values. For mitigations related to an underground blowout, reference section 13 discussing non-conventional kill methods (i.e., sandwich kill, barite pill, DOBC pill).

6.4.6 Additional Considerations

All mud conditioning, mixing, and transfer between pits shall be done in isolation from drilling activities designed to identify mud losses while drilling and mud gains with pumps off.

All instrumentation should be calibrated. If multiple instruments are used on any parameter, the values should be correlated.

Synthetic based muds present issues related to their pressure, volume, and temperature that impact HTHP and deep-water wells.

Pipe movements and varying circulation rates affect ECD and ESD.

When penetrating condensate zones, drilled gas can go into solution and be circulated toward the rig. The gas is known to enter solution in both synthetic base muds and lignosulfonate water base muds. The PVT behavior can be such that when the gas comes out of solution, a mini-blowout can occur. The thickness of condensate zones determines the volume of drilled gas available to go into solution.

The volume of liquid contained in the cuttings is usually so small that unless accompanied by gas, it will not significantly affect the drilling fluid density.

7 Well Planning

7.1 Introduction

Well control starts with the planning phase of a well. A well control plan and contingency plan are developed beforehand with the objective of keeping a well under primary control during operations. Subsurface conditions should be predicted, detected, and controlled. Consideration should be given to the anticipated well conditions, the equipment used, the procedures to be followed, and competency of the crew.

7.2 Data Availability and Gathering

7.2.1 General

The following types of data are useful and, if available, should be obtained:

- Lithology,
- Seismic,
- Downhole surveys,
- Drill stem tests,
- Offset well pressure tests,
- Drilling logs (bit records and penetration rates),
- Mud logs,
- Temperature and pressure gradients,
- Drilling fluid programs,
- Cementing programs and techniques,
- Drilling program,
- Hazards,
- Environmental conditions,
- Logistics,
- Communications,
- Safety practices,
- Well control indications and problems,
- Remedial operations,

- Plug and abandonment, and
- Government regulatory requirements.

7.2.2 Geological and Geophysical Data

Seismic data should be correlated to data from wells in the area where the well is proposed. Regional and area geological studies and maps, high-resolution 3D seismic data, and sequence stratigraphy are among the information and methods that can aid in predicting the presence of permeable formations and pressures.

Based on the information and predictions, well locations, well path, drilling fluids, well logging, and casing programs can be designed or modified. On deviated and closely spaced wells, care should be taken not to drill into other wells or in proximity close enough to communicate hydraulically between wells.

7.2.3 Formation Pressure

All available engineering, geophysical and geological information should be analyzed to predict formation fracture gradients, pore pressure, and shallow hazards. Investigate the area for the possibility of charged or depleted formations from previous drilling or production. Pressure profiles should be made and plans prepared for handling under- and over-pressured formations, both shallow and deep. Pressure data and formation strength are fundamental to the design of the drilling program, drilling fluids required, casing strings, and selection of best operating practices. Prediction of formation pressure can be difficult in exploration wells; seismic data and field analogs may be the only data available. As more experience is gained in a field, the problem is minimized as correlation with nearby wells improves predictability.

7.2.4 Drilling Data Utilization

Several methods or indicators that can be used to detect abnormal pressure while drilling, including:

- Drilling rate or “d” exponent;
- Sloughing shale;
- Shale density;
- Gas units in drilling fluid;
- Chloride increases in drilling fluid;
- Drilling fluid properties;
- Temperature measurements;
- Bentonite content in shale;
- Paleontology information;
- Wireline logs; and
- Torque and drag.

Data can be obtained from previously drilled wells and obtained and interpreted while drilling. Real time pressure while drilling (PWD) and real time logging while drilling (LWD) and can provide instant feedback on several parameters such as gamma ray, resistivity, formation density, temperature, and pressure. This data can be correlated to geologic and geophysical data to provide warning of potential well control problems such as over pressured shallow water or shallow gas zones and pressure transition zones. However, LWD/PWD tools are located above the bit, and this must be accounted for as the bit may have already penetrated a formation containing abnormal pressures before the logging tool detects the formation.

7.2.6 Plug and Abandonment

Plug and abandonment rules and regulations, as well as actual plug and abandonment data on area wells, can provide insight into problems that may have occurred with offset wells and lead to useful contingency planning for future operations.

7.3 Shallow Hazards

7.3.1 General

Shallow hazards can be gas or liquid flows and are problematic wherever they occur. Drilling operations involving any land or bottom supported marine structure, legs, or a barge are particularly susceptible to shallow hazards. These operations include all onshore drilling operations. In the marine environment, they include jack-up drilling rigs, barge rigs, production platforms, and templates.

In addition to the other hazards associated with uncontrolled flow to the surface, gas flows (and to some degree, liquid flow) may cause damage to, or failure of, the rig foundation. Onshore and offshore bottom supported drilling units, production platforms, and templates are vulnerable to foundation failure under these conditions and may overturn or collapse. For these reasons, BOPs are not used until surface casing is set.

Diverter systems should be installed before surface casing is set since they are not designed to shut-in the well, but to divert gas or liquid flows away from the rig to a safe place.

7.3.2 Guidelines for Use of Diverter Systems

Following are general guidelines for possible use of diverter systems. There may be other alternatives that are as, or more, acceptable for site-specific conditions or environments. For more information, refer to API 64, *Diverter Equipment Systems*.

1) A diverter system shall be installed if there is an expectation of encountering gas or fluid flows in quantities sufficient to cause well control or operational problems before the BOP is installed on a surface wellhead.

2) A diverter system shall be installed in drilling operations utilizing a marine riser and subsea BOP equipment. Gas may pass the BOPs before they are closed on a kick or gas may be trapped below the BOPs in normal kill operations. A diverter can provide additional flexibility and safety when removing gas in the marine riser.

3) On drilling locations where personnel or equipment cannot readily evacuate the immediate location in the event of a complete loss of well control, with or without BOPs in use, a diverter system should be considered as additional redundancy and safety to divert uncontrolled well flow while taking corrective action and evacuating personnel.

7.3.3 Shallow Water Flows in Deepwater

Shallow water flows may result in loss of well support, buckling and collapse of the casing, and poor wellbore integrity that can result in loss of well control at a later stage in the operation. A risk assessment should be performed to identify ways in which the hazard can be avoided. Common mitigations to typical risks include, but are not limited to, top setting the shallow hazard if a competent casing seat can be achieved, moving the rig, or directional drilling around the shallow hazard, controlling ROP, drilling a pilot hole, and maintaining proper ECD (e.g., cuttings efficiency).

The real time information provided by LWD can be beneficial by allowing timely correlation of the formations with available geological and geophysical data.

7.3.4 Other References

Guidelines for predicting, drilling, cementing, and controlling shallow water flows, including several descriptions and illustrations of mechanical shallow water flow shut-off devices are available in the *IADC Deepwater Well Control Guidelines* and API RP65.

7.4 Casing

7.4.1 General

When considering well control, the most important casing requirements are tube strength, setting depth, and size. Misalignment, hydrogen sulfide exposure, deviated holes, doglegs, long drilling times, coarse hardbanding, and corrosion are some of the factors affecting design and performance. Inspection and test schedules should consider these factors. Each new string should be set at a depth so that formation fracture gradients will exceed anticipated gradients of the drilling fluid. The internal pressure and external collapse ratings of casing should be designed to handle the anticipated pressures.

7.4.2 Casing Wear

Wear bushings should be used. If the surface pipe becomes worn or holed, closure on a kick can allow formation fluids to broach to the surface or allow an underground blowout. If any casing string is exposed to longer than anticipated drilling operations, casing thickness should be measured.

7.4.3 Setting Depths

These will vary according to well conditions. Surface casing is the first well control string and should be set into formations competent to contain the anticipated wellbore pressure until the next casing string is set. The casing should be pressure tested prior to drilling out the casing shoe. A pressure test of the cement job and a formation competency test should be performed after drilling out below each casing string. These tests will dictate the drilling fluid densities and surface pressure that will be allowed before the next string is set.

7.4.4 Existing Wells

The setting depth and condition of the casing should be evaluated before drilling, workover, or well service operations. Depending on the evaluation, testing of the casing may be needed.

7.4.5 Casing and Liner Landing and Handling Practices

Casing and liner running and handling procedures should be evaluated to include:

- Prevention of buckling and joint failure
- Handling a kick if non-shearable/sealable tubulars/equipment are across BOPs
- Converting from autofill and confirm conversion
- Shutting-in on a kick
- Well monitoring
- Other operations (e.g., draining the surface stack, setting surface slips)

7.4.6 Contingency Plans

Contingency plans that include actions to take should be established for the following events:

- Loss of wellhead integrity,

- Casing failure,
- Broaching,
- Relief wells,
- Underground blowout, and
- Equipment failure.

7.5 Cementing

Casings should be adequately cemented to confine wellbore fluids; this is especially important in surface and conductor cementing. A good cement job is essential so any pressure encountered later will not break out around the casing and broach to the surface. Drilling fluid returns should be monitored while cementing to determine if there is a gain or loss. Lightweight cements are sometimes necessary to keep from breaking down the formation(s) encountered. When cementing subsea, a remotely operated vehicle (ROV) should be used to ensure cement returns have reached the mudline.

7.6 Blowout Prevention Equipment Selection

BOP equipment shall conform to the requirements in API 53. The rig's well control choke manifold shall only be used for well control operations.

API RP 7G, *Recommended Practice for Drill Stem Design and Operating Limits*

7.7 Drilling Fluid

7.7.1 General

A variety of fluids are available to satisfy well objectives: air, nitrogen, natural gas, foam, water-based, synthetic-based, oil-based, and specialized heavy weight brines (see section 4.5). The following are some considerations for well planning.

7.7.2 Maintenance of Overbalance

Overbalance shall be maintained with a fluid, an applied pressure, or a combination thereof. Changes in drilling fluid density can be caused by drilled solids or fluid influxes. Controlled drilling rates are advisable in certain cases where ECD is approaching fracture pressure or gas-filled formations which can cause severe fluid density cuts.

7.7.3 Managed Pressure Drilling

Refer to API 92 series as appropriate for further information.

7.7.4 Underbalanced Drilling

Refer to API 92U for further information.

7.7.5 Well Monitoring Equipment

It is essential to monitor the quality and quantity of fluid in the system. Fluid measuring devices that will monitor the active drilling fluid volume shall be used. Several methods of combining different types of equipment can be used, depending upon the well requirements. These can include:

1) Pump stroke counters;

2) Flow line sensors with alarms;

3) Pit level recorders with alarms;

4) Stripping tank;

5) Trip gain-and-loss meters; and

6) Trip tanks.

7.7.6 Fluid Storage

Adequate supplies of fluids are necessary for well control operations. Logistics and storage should be thoroughly reviewed and planned, especially offshore where space on a drilling rig or platform is limited. Priority should be considered for storage of adequate supplies of base fluids, weighting material, and loss circulation materials.

Procedures and fluid recipes should be pre-planned and readily available. Consideration should be given to having kill weight or LCM fluids pre-mixed and available during certain operations such as drilling into a suspected shallow gas formation or a transition zone.

In floating drilling operations, plans should be made to recover and store riser fluids during planned disconnects, especially when using oil or synthetic based drilling fluids and certain heavy brines.

7.7.7 Mud-Gas Separator

Selection and sizing of the mud-gas separator should be done in the pre-planning stage before rig selection. Refer to API 16C for information on Mud Gas Separator sizing requirements.

Refer to API 53 for operation and maintenance of the MGS.

7.7.8 Hydrates

Hydrates can form in surface and subsea operations. An analysis of hydrate formation potential and the associated risks should be performed. Appropriate contingency plans and well control procedures should be developed. Hydrate prevention programs should be implemented.

For more information on hydrate issues in subsea environments, refer to the *IADC Deepwater Well Control Guidelines*.

7.8 Service Operations

Well planning should include service operations. These include, but are not limited to: logging, coring, fishing, drill stem testing, slick-line, and coiled tubing operations (refer to API 16ST *Recommended Practice for Coiled Tubing Well Controls Equipment Systems).* Considerations for these operations include:

- Keeping the hole full
- Avoiding surge and swabbing
- Continuous wellbore monitoring
- Consideration of lubricator design and best operating practice for high-pressure wireline work
- Procedures for stuck pipe and tools
- Procedures for plugged tubulars and bits when fishing or coring

- Stripping procedures and equipment arrangement
- The hazards and material requirements associated with sour gas

7.9 Kick Response Plans

Once all the well data are gathered and a general well plan is complete, attention should focus on response to potential kicks during drilling and workover operations. Following are some of the items that should be considered:

- Pre-kick data requirements and collection for each stage of operations
- Divert procedures
- BOP close-in procedure selection at each stage
- Kicks while tripping pipe in and out of the hole
- Kicks while running in or out of the hole with casing and liner
- Underground blowout
- Stuck pipe procedures
- Plugged or packed-off pipe or bit
- Fluid compatibility and interactions
- Gas bubble migration
- Lost circulation–recipes and procedures
- Riser disconnect procedures–planned and emergency
- Well modeling of kick potential
- Equipment selection suitability

7.10 Riser Disconnect

Situations that require the release of the marine riser should be considered. These can include well or equipment problems, severe weather, eddy currents, planned operations, etc. When required the well shall be secured and the riser disconnected before damage occurs to the wellhead, the drilling rig, or well control equipment.

If a planned or unplanned riser disconnect is required while drilling or tripping pipe, the system should be capable to:

- Hang-off the drill pipe on pipe rams;
- Shear the pipe;
- Effect a seal on the wellbore;
- Disconnect the lower marine riser package;
- Clear the BOP with the lower marine riser package;

- Dissipate any energy in the riser/riser tensioning system; and,
- Capture the riser.

Those situations and conditions where a riser disconnect procedure are to be initiated shall be clearly defined. Disconnect procedures should be prepared. Procedures to select the proper disconnect mode should be prepared. Crew training and drill exercises should also be prepared. For additional information and recommendations, refer to the *IADC Deepwater Well Control Guidelines*. Refer to section 10.4 *Special Subsea Procedures* for further information.

7.11 Simultaneous Operations

Plans and risk assessments for simultaneous operations should be performed when drilling operations, workover operations, rig maintenance, etc. are conducted that can affect well control. Examples include: a drilling and production pad, an offshore drilling and production platform, drilling/workover operations in a gas storage field or a natural gas plant, or potential for offset well stimulating activities communicating with a well drilling operation. These facilities all have additional exposure due to the presence of oil and gas processing facilities, pipelines and pipeline connections, and producing wells as well as the potential for production and service personnel nearby or on-board.

Consideration should be given to shut-in producing wells and oil and gas processing facilities during certain simultaneous operations such as moving the rig or hoisting loads near or above producing wellheads, piping, or process vessels. Operations on one well should not cause loss of well control on another.

7.12 Emergency Management Plan

7.12.1 General

An emergency management plan shall be established and approved prior to commencing well operations. The plan shall address foreseeable emergency scenarios and define roles, responsibilities, resources, and decision-making processes necessary to ensure personnel safety and environmental protection. At a minimum, the emergency management plan should include the following elements:

- System access and egress, including evacuation and escape routes;
- Required equipment, including emergency and safety-critical systems;
- Required services, such as well control, fire response, and external support;
- Safety and medical provisions, including first aid, medical response, and medevac arrangements;
- Communication plan and systems, including internal and external notification protocols;
- Gas dispersion modeling, where applicable, to support emergency response planning and risk mitigation.

For additional information and recommendations regarding system access, escape, evacuation, and rescue arrangements, refer to **ISO 15544**, *Petroleum and natural gas industries — Offshore production installations — Requirements and guidelines for emergency response* (First edition, 2000).

For additional information and recommendations regarding safety and medical preparedness for drilling and well operations, including first aid and medical response, refer to **API RP 54**, *Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operations* (Fourth edition, 2019).

For additional information and recommendations regarding gas dispersion and consequence analysis in support of emergency preparedness, refer to **ISO 17776**, *Petroleum and natural gas industries — Offshore production installations — Major accident hazard management* (Second edition, 2016).

The following documents provide complementary guidance and recommendations relevant to emergency management planning for offshore drilling and well operations:

- API RP 75 - Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations (Fourth edition, 2019)
- BSEE – 30 CFR Part 250 - Oil and Gas and Sulphur Operations in the Outer Continental Shelf
- IOGP Report 699 — Offshore Emergency Response Services (2021)

7.13 Training and Instruction

7.13.1 General

The following are general guidelines for personnel training and instruction:

1) Formal training and instruction in well control procedures should be reviewed and updated as necessary prior to spudding.
2) Written emergency procedures should be developed prior to spudding that detail specific emergency action plans.
3) Well control drills shall be prepared in advance and designed to measure personnel and system response to various scenarios.
4) Well control drills shall be conducted at appropriate intervals to ensure personnel are capable of quickly and competently reacting to various scenarios.
5) Well control drills shall be documented and analyzed to identify areas where improvement is required.
6) Deficiencies identified in the drills shall be documented and corrective actions taken.
7) Emergency plans, training, and drills should be updated as conditions change.

7.13.2 Personnel

Personnel involved in well control operations shall be certified for their role by an industry recognized well control training organization.

Personnel involved in well control operations should be knowledgeable with the installation and operation of the well control system components specific to their role and capable of reacting quickly and efficiently to potential situations requiring their use.

8 Well Control Procedures for Surface Diverter Installations

8.1 Purpose

The diverter is a device used to seal the annulus around pipe in the wellbore or the open hole when it is desired to divert wellbore fluids away from the drilling rig and personnel. A diverter system is not designed to shut-in or halt flow; rather it permits routing of the flow to a safe distance away from the rig with minimal backpressure. Diverters are primarily used to divert flow in situations such as:

- Shallow water and gas flows,
- Break-out gas flows,

- Gas flows in a marine drilling riser.

8.2 Installation of Equipment

Information on equipment and installation can be found in the following:

- API 64 – Diverter Equipment Systems
- API RP 16Q – Design, Selection, Operation, and Maintenance of Marine Drilling Riser Systems

8.3 Diverter Operation

8.3.1 General

Following are recommendations for diverter operation and controlling diverted flow. The diverter shall not be closed while all diverter lines are closed to prevent shutting in the well except during testing.

If the diverter is closed on an uncontrolled flowing well, the rig personnel should evacuate immediately.

8.3.2 Kick or Suspected Kick

When drilling through a diverter and a kick is indicated or suspected:

- Immediately stop drilling;
- Pick up to clear the kelly or tool joints;
- Close the diverter;
- Sound the alarm;
- Check for flow through the open diverter line;
- Allow the well to flow through the open diverter line;
- Continue pumping water or drilling fluid;
- Evacuate rig personnel if uncontrolled well flow.

8.3.3 Divert Pressure Trapped Under a Subsea BOP

If a subsea stack has been used to control a kick in normal well control operations, the gas bleed line or a stack gas sweeping procedure should be used to remove trapped gas under a closed preventer. When necessary, the diverter should be used to divert the residual gas that accumulates under the BOPs not removed by stack gas sweeping procedure.

8.3.4 Controlling Flow

Pumping at a higher rate improves the drilling fluid/gas ratio and creates a small increase in bottom-hole pressure due to annular friction pressure. Increasing the drilling fluid density at a higher rate increases hydrostatic pressure and can eventually stop flow. If the rig personnel are not evacuated, the following guidance should be considered for mitigating well flow:

- Pump at the maximum rate;
- Increase drilling fluid density while pumping;
- If the drilling fluid supply is depleted, continue by pumping water.

  Note: A reserve supply of drilling fluid weighing 1 to 2 ppg above expected, can be stored on location.

For more information on diverters and shallow gas flows, refer to 4.14, 7.3, 7.3.1, and API 64.

8.4 Diverter Stripping Operations

Diverters should not be used for stripping pipe into the hole while diverting well flow.

9 Well Control Plan—Surface BOPs

9.1 Well Control Goals

1) Always maintain primary well control of the well during well operations by maintaining pressure in the wellbore equal or greater than the formation pressure to prevent formation flow.
2) Effectively implement secondary well control options whenever primary control of the well is lost.
3) Restore primary well control using well control methods referenced in this standard.

9.2 Pre-Kick Planning

9.2.1 General

A plan shall be in place for activating the BOPs in the event of a kick prior to the start of operations and shall be documented in the well control bridging document between the operator and the contractor. The plan shall be discussed with personnel involved in well control.

This plan shall define:

a.) Well control roles and responsibilities
b.) Shut-in procedure
c.) Well kill method(s) to be used to re-establish the primary well barrier

A stack-up diagram of the BOPs shall be available at the driller's station showing:

a.) BOP configuration, bore diameter, distances between rams and annulars, distances to wellhead, distances below rig floor of the BOP stack components
b.) Pressure ratings of the BOP stack components

Operator's representative and contractor rig-site management shall verify that:

a.) Rig-site personnel involved in well control operations have received job-specific well control training
b.) Rig-site personnel involved in well control operations can demonstrate well control competency specific to their role

c.) Operator representatives, drilling contractor OIMs, rig managers, toolpushers, drillers, assistant drillers, and derrickmen possess the appropriate well control certification (e.g., introductory level, drillers level, supervisory level)

9.2.2 Well Control Kill Sheet

An appropriate well control worksheet (Kill Sheet) for the type of well, shall be prepared and available at the Driller's station.

The Kill Sheet contains pre-recorded information which shall be kept up-to-date. Prior to spudding the well, and daily while drilling or after operations which result in a significant change in circulating system pressure, the operator's representative, OIM, rig manager, toolpusher or designate(s) are responsible for updating the well control worksheet (Kill Sheet).

a) Pertinent tubular data such as weight, grade, casing internal yield pressure (i.e., burst), ID, length.

b) Rated Working Pressure of the surface BOP equipment, wellhead, and casing string.

c) MAASP to cause formation fracture based on present drilling fluid density.

Note: This pressure may be calculated using either estimated or measured fracture drilling fluid density. If formation leak-off pressure is measured, use this pressure to determine the fracture drilling fluid density and to calculate the fracture pressure.

d) Slow circulating rate pressures needed for killing the well (typically 2-3 rates are recorded on the IADC daily drilling report), SPM, BPM, and depth at which pressures were measured

e) SIDPP, SICP, MW, MD, TVD, Kick Volume (pit gain)

f) The tubular (drill string, BHA, etc.) and annular capacities (volumes), and surface line volumes

g) Strokes and time for surface to bit, open hole section (i.e., non-cased), bottoms up, and surface to surface

h) Calculated KWM, MAASP, ICP, FCP

i) Kill pump schedule

9.2.3 Equipment Inspection and Test Schedule

Refer to API 53 for the inspection and test requirements of well control equipment.

Warning devices should be inspected before each tour and maintained operational (e.g., pit level recorders, flow indicators, gas detectors, lights, horns).

9.2.4 Drilling Fluid System

There should be a sufficient inventory of materials to handle, within reason, unexpected well flow or lost circulation condition.

9.3 Kick Indications

9.3.1 Primary Indication of Kick

Upon primary indication of a kick, forward operations shall be suspended and the well secured. Check for pressure on the casing pressure gauge.

9.3.2 Secondary Indication of Kick

Stop drilling (or other operation), stop pumps, and check for flow. If kick is confirmed secure the well.

9.3.3 Immediate Action When a Kick Occurs

9.3.3.1 While drilling

Stop drilling

a.) Space out to position the drill pipe such that tool joints are clear of the BOP ram closures.

b.) Shut down the pumps to prevent trapping pressure on the well, which will increase annular pressure during the well kill and potentially break down the formation.

c.) Hard shut-in the well

d.) Confirm well shut-in by checking for flow

9.3.3.2 While tripping

Stop Tripping

a.) Stab Drill Pipe Safety Valve and close same

b.) Space out to position the drill pipe such that tool joints are clear of the BOP ram closures

c.) Hard shut-in the well

d.) Confirm well shut-in by checking for flow

e.) Install IBOP and prepare to strip back to bottom.

There are two commonly used shut-in procedures:

a.) Hard shut-in

b.) Soft shut-in

Hard shut-in:

a.) Close preventer

b.) Open HCR or other valves as necessary to enable reading casing pressure at the choke panel

Soft shut-in:

a.) Open the choke

b.) Open HCR or other valves as necessary to enable reading casing pressure at the choke panel

c.) Close preventer

d.) Close choke

Observe casing pressure. Allow shut-in pressures to stabilize and record the stabilized drill pipe and casing pressures. Check for increased pressure due to gas migration.

Determine the kick volume from the pit gain observed prior to shutting-in the well. Mud compressibility may need to be considered.

Using the stabilized Shut-in Drill Pipe Pressure (SIDPP), calculate the drilling fluid density required to balance the formation pressure and re-establish the primary fluid barrier. This fluid density is alternately referred to as “Kill Mud Weight” (KMW) or Kill Weight Mud. In practice, this is the mud weight required to “kill” the kick and re-establish overbalance on the well, thereby restoring the primary well control barrier.

Update the well control worksheet (Kill Sheet).

Adjust pit volume to allow for increases in pit volume due to:

a.) Pit gain due to gas expansion while circulating out the kick.

b.) Pit gain due to kick fluid volume.

c.) Pit gain due to barite addition while weighting the mud system up to the required KWM density.

Check pressures on the drill pipe and all annuli of the well.

Prepare to conduct well control operations using the selected well kill method to restore the primary barrier.

9.3.4 Removing the Influx/Restore Primary Well Control Barrier

9.3.4.1 General

Once a kick occurs, there are four well control methods commonly used to remove the influx from the well and restore the primary well control barrier. The method chosen will depend on several factors, including:

a.) Composition of the influx (water, oil, gas, H_2S, CO_2, etc.)

b.) Condition of the rig (ability to pump)

c.) Wellbore geometry

The four well control methods commonly used are:

a.) Driller’s method

b.) Wait and Weight method (i.e., Engineer’s method)

c.) Lube and Bleed method (and variations)

d.) Bullheading

The Driller’s Method and the Wait and Weight are the most frequently used constant bottom-hole pressure well control methods. They are simple, easy to understand and straightforward in application. Both methods require that the rig be capable of circulating.

The Lube and Bleed method is a constant bottom hole pressure well control method that is most commonly used when circulation is not possible, either due to some type of mechanical problem with the rig or wellbore which prevents circulation, or the pipe being out of the hole, as in a swabbed kick. The procedure does require that rig-site personnel have the ability to pump fluid into the well. This procedure requires gas at surface with stabilized surface pressures. If gas is not at surface, the volumetric method should be used to allow the gas to expand as it migrates to surface.

Bullheading is a procedure most used when acid gases, such as H_2S or CO_2 are encountered or suspected. Bullheading may be performed as a constant bottom hole pressure method by controlling surface pump pressure such that the bottom hole pressure remains constant, or the procedure may simply consist of displacing the formation fluids (bullheading) into the formation without concern as to the effects on bottom hole pressure. In either case, the objective is to prevent handling the formation fluids, or “kick”, at surface by forcing them back into the formation.

9.3.5 Circulating Out Using the Driller’s Method

This procedure dictates that the invading fluid (flow) be circulated out before increasing the drilling fluid density. Constant drill pipe pressure control is required throughout the initial circulation (refer to 4.10.2 and its subparagraphs).

1) Open the choke while bringing the pump to the kill rate (refer to 9.5.3). Increase the pump rate slowly while holding the casing pressure at its initial shut-in value by adjusting choke.

2) When the kill-rate is reached, the observed drill pipe pressure should be equal to the calculated initial circulating pressure. If not, investigate cause (refer to 9.5.4). If no cause is evident, use the observed drill pipe pressure and update the kill sheet.

3) Continue to pump drilling fluid of the original density at the kill-rate, maintaining the drill pipe pressure constant by adjusting the choke. Keep the drill pipe pressure above the ICP plus safety margin and below the fracture pressure. Continue to pump until the influx is removed.

4) Stop the pump while holding the casing pressure constant. The shut-in drill pipe and casing pressures should be equal and approximately the same as the initial shut-in drill pipe pressure. If not, circulate additional drilling fluid as in step 3 until the well is free of invading fluids.

5) Increase the drilling fluid density in the suction pit to the density required to kill the well. Monitor drill pipe and casing pressures. Percolation of gas causes shut-in drill pipe and casing pressures to increase. If this occurs repeat steps 4 and 5.

6) Circulate kill weight drilling fluid, establishing circulation by bringing the pumps up to speed while holding the casing pressure constant at the value observed in the step 3 procedure plus any desired safety factor. Hold the pump rate constant at the kill-rate. Maintain casing pressure constant by adjusting the choke until the drill pipe is displaced with kill weight fluid.

   Note: At this point the drill pipe pressure is expected to decrease from the ICP to the FCP due to the increase hydrostatic pressure of the kill weight fluid

7) When the drill string has been displaced with kill weight drilling fluid, observe the drill pipe pressure. This is the FCP.

8) Continue to circulate at a constant rate holding the drill pipe pressure constant at the pressure observed in step 7 (FCP) by adjusting the choke. When the kill weight drilling fluid reaches the surface, the casing pressure should approach zero.

9) Simultaneously close the choke and stop the pump. The shut-in drill pipe and casing pressure should be zero.

10) If the shut-in pressures are not zero, check the well for flow. If the well will flow, repeat the aforesaid operations beginning with step 5 and recalculate the drilling fluid density required to kill the well based on the observed shut-in pressure.

11) If shut-in pressures in step 9 are zero and well will not flow, prepare to open the preventers. Caution: If, for some reason, more than one preventer is closed, pressure can be trapped between the closed preventers; therefore, the choke should remain open.

12) Open preventers and resume operations.

9.3.6 Wait and Weight Method

The well is shut-in on the kick; the drilling fluid density is increased in the pits as required; then the kick is circulated out with the weighted fluid (refer to 4.10.3 and its subparagraphs). If migration is detected during the wait period while weighting up the fluid and wellbore pressures approach the casing seat or fracture pressure, an alternative well control method should be used.

1) Mix kill weight fluid. Note how long it takes to mix and at what rate the equipment can continue to mix to the proper drilling fluid density. This gives a guide to selection of proper kill or displacement rate. To avoid shutdown, do not displace at a rate exceeding mixing rate (refer to Annex B). If the mixing rate is insufficient to avoid shutdown, kill weight mud should be premixed and available prior to drilling that section.

2) While mixing kill weight fluid, review and update pump output volume data and complete the well control worksheet.

3) Open and adjust the choke to hold casing pressure constant at its present shut-in value while bringing the pump up (slowly, if possible) to the kill-rate. Hold the kill-rate constant. At this time, the observed drill pipe pressure should be equal to the calculated initial circulating pressure. If they are not approximately equal, then use the observed drill pipe pressure as the initial circulating pressure and re-calculate the drill pipe schedule.

4) If the circulating pressure is correct, displace drill pipe at a constant pump rate in accordance with the pumping schedule on the well control worksheet. Maintain drill pipe pressure as per schedule by adjusting the choke.

5) Maintain constant pump rate and drilling fluid density. After the kill fluid reaches the bit, maintain the drill pipe pressure constant at the final circulating pressure.

6) Continue pumping until kill fluid is circulated to the surface. Then stop the pump and shut-in the well. If sufficient kill fluid density was used during this circulation, the pressure should be zero.

7) If pressures are not zero, check the well for flow. If flow is detected, repeat operations in steps 1 through 6, with drilling fluid density adjustments.

8) If shut-in pressures in step 6 are zero, check well for flow before opening preventers. Caution: If, for some reason, more than one preventer is closed, pressure may be trapped between the closed preventers; therefore, the choke should remain open.

9) Open preventers and resume operations.

9.3.7 Volumetric Method

Volumetric is a method of controlling bottom-hole pressure (BHP) with a migrating kick when circulation is not possible. Examples include:

- a) Pumps are inoperative.
- b) Plugged drill string.
- c) Drill pipe is above the kick.
- d) Pipe is out of the hole.
- e) Packed off below kick.

Note: The Volumetric Method is a pressure management method and not a well kill method.

Volumetric Method Procedure:

1. Select a Safety Factor (SF) and Pressure Increment (PI) within the design limitations of the well.

2. Based on wellbore geometry, calculate the Mud Increment (MI) that in hydrostatic pressure (HP) = the (PI) selected.

3. Wait for the surface casing pressure to increase by the selected SF and PI

4. Hold casing pressure (CP) constant while making small incremental bleeds of mud until the equivalent HP bled from the well is equal to the PI selected.

5. Close choke and wait for CP to increase again by the selected PI.

6. Repeat steps 4 and 5 until:

    - Casing pressure stops increasing and stabilizes, or

    - Operations can revert to a preferred circulating constant bottom hole pressure method.

Note: The surface casing pressure will increase to the equivalent PI in each step of the Volumetric Method which is a controlled proportional exchange of increased surface pressure to compensate for the loss of hydrostatic pressure being bled from the well to maintain a relatively constant BHP.

9.4 Drill String Off-Bottom

Well control operations with the bit off-bottom offer less chance of achieving hydrostatic control of formation pressure. If the bit is off-bottom, consider stripping the drill pipe back to bottom (refer to 12.8), or a top-kill method (e.g., riser cap). If the drill pipe is stripped to bottom, a drill pipe safety valve and inside BOP should be installed. If it is impractical or unsafe to strip back to the bottom, consider using bullheading or volumetric method of well control.

9.5 High-Angle and Horizontal Wellbores

9.5.1 General

The techniques used in conventional well control can apply to high-angle or horizontal wells. The high angles and small hole sizes require some additional considerations and precautions.

9.5.2 Kicks and Kick Detection

Compared to a vertical wellbore, the characteristics of a kick in a high-angle or horizontal well include:

a) Potential kick volume can be larger due to the long, high-angle section that may be through the kicking formation.

b) ECD is relatively large due to the length of measured depth.

c) Kick detection can be complicated in a high-angle or horizontal wellbore due to the small hydrostatic pressure difference; pit gain and monitoring for drilling fluid flow are extremely important as these will be the first indicators.

d) Gas migration will occur relatively slowly in the high-angle wellbore and may not occur at all in the horizontal portion of the wellbore.

9.5.3 Well Control

Once a kick is detected, conventional shut-in and well kill methods are effective. The hard shut-in procedure is recommended to minimize kick influx due to the potential high productivity of the horizontal or high-angle formation. Some factors to consider after shut-in include:

a) Zero shut-in pressures do not mean a kick has not occurred. A positive pit gain can indicate a kick that is still in the high-angle or horizontal hole section.

b) Shut-in casing and shut-in drill pipe pressures will be very close due to little or no reduction in the annular hydrostatic pressure in high-angle or horizontal wellbores.

c) Determining influx fluid type based on shut-in pressures and pit gain are not valid with high-angle/horizontal sections. However, increasing casing pressure indicates a gas kick expanding above the horizontal section.

d) The pump schedule for displacing the drill string with kill weight fluid is more complex due to the horizontal section.

9.6 Reference Notes for Section 9

9.6.1 Trapped Pressure

Trapped pressure is a type of overbalance pressure in which pressure recorded on the drill pipe or annulus greater than the amount needed to balance the formation pressure. Trapped pressure can occur in the system in several ways. Common ways include bumping the float, gas migrating up the annulus, or closing the well in before the mud pumps have stopped running. Using pressure readings containing trapped pressure results in erroneous kill calculations.

It is good practice to check for trapped pressure after each well shut-in using the volumetric bleed technique. The recommended check consists of bleeding a predetermined volume from the annulus slowly through an adjustable choke. After choke closure, monitor casing and drill pipe pressure to detect a decrease in pressure from the initial values. The maximum volume bled should be limited to one barrel or less. If a pressure decrease is seen repeat the volumetric bleed until no decrease is seen. If drill pipe pressure does not decrease, pressure was not trapped.

9.6.2 Required Drilling Fluid Density Calculations

After the shut-in casing pressure has stabilized, the shut-in drill pipe pressure should be determined. The required kill weight fluid density is then calculated using the initial static, shut-in drill pipe pressure (Refer to Annex B for equation).

Prior to mixing kill fluid, the pit volume should be adjusted to allow for gas expansion and barite addition anticipated during the kill circulation.

9.6.3 Kill-rate

Rig equipment may be the primary factor in selecting a kill-rate for the well (refer to 4.8.5 for a description of kill-rate and 4.13 for information on subsea choke lines, another factor affecting kill-rate selection). A rate should be selected which will eliminate interruptions. Some of the considerations are:

a) Drilling fluid mixing capabilities, i.e., displacement rate should not exceed the mixing rate;

b) Surface fluid handling equipment, e.g., the mud-gas separator;

c) Minimum pump speeds (pump crippling may be required);

d) Pump pressure limitations;

e) Choke line friction; and

f) Choke-manipulation delays (human factors). Lower kill-rates should be selected to minimize interruptions.

9.6.4 Initial Circulating Pressure

In the event the observed initial drill pipe circulating pressure does not equal or approximate the calculated value the reasons for this difference should be determined. This may be caused by any of several factors including, but not limited to:

a) Improper choke management during pump startup,

b) Calculation mistake,

c) Washout,

d) Pump failure,

e) Plugged bit nozzle or hole pack-off,

f) Erroneous gauges, and

g) Changes in mud properties.

Recommendations for remedial actions for several of the factors listed above are covered in Section 12.

10 Well Control Procedures for Subsea BOPs

10.1 General

The procedures used to control wells equipped with subsea blowout prevention equipment are essentially the same as for those with surface control. The purpose of this Section is to discuss additional factors related to subsea well control and show how they can be applied with the procedures recommended in Section 9, "Well Control Procedures—Surface BOPs."

10.2 Additional Causes of Kicks Unique to Subsea Operations

10.2.1 Loss of Integrity in the Marine Riser

Wellbore hydrostatic pressure is a function of the height and density of the drilling fluid column from the flow line to the depth of interest. If a riser fails, leaks, or becomes disconnected, the drilling fluid gradient in the riser is lost and replaced by a seawater gradient (approximately 0.445 psi/ft-8.56 lb/gal) from the point of failure to sea level. The loss of wellbore hydrostatic pressure associated with this situation can sometimes be sufficient to allow a well to flow. The first response should be to close the BOPs. In some situations, the drilling fluid density may be sufficient to compensate for the loss of hydrostatic pressure. This is referred to as riser margin. If no riser margin exists, the loss of hydrostatic pressure should be restored prior to opening the BOP.

10.2.2 Trapped Gas Below BOPs

During the circulation of a gas influx out of the hole, there is a possibility that gas becomes trapped between the closed preventer and the side outlet in use during the kill operation. This accumulation of gas will be under the hydrostatic pressure of the fluid from the BOP choke outlet to surface. This volume of gas under pressure can result in rapid unloading of the riser if not properly managed and removed through a controlled process. Rapid unloading of riser due to rapid gas expansion could result in injury to people, damage to equipment and a pollution incident. Following circulation of a gas kick, trapped gas shall be removed or managed using an appropriate process to address this risk.

Three common methods are recommended for the removal of trapped gas.

The following 2 methods provide a generic guide for the removal of trapped gas from a subsea BOP. An exact procedure shall be developed and included in the rig-specific procedures.

10.2.2.1 Bleed Valve Below Preventer Method

Allows circulation of bubble out very nearly completely; remaining bubble is very small. This method has the advantages of being the safest and quickest method to remove the bubble and is the preferred method if equipment allows this technique. To execute this process, with the BOP closed, using kill fluid, displace volume in the stack plus the volume of the return line (choke or kill) to the surface. If this option is not available, the methods below are recommended.

10.2.2.2 High-Rate Circulation Method

Prior to opening the closed BOP component circulating across the BOP at a rate in excess of the SCRs used during the kill operation. It is recommended to pump at a rate of 8-10 bpm with the lower most preventer closed to mitigate any pressure impact to the well.

1. With the lower annular remaining closed, isolate the wellbore with the lower pipe ram.
2. Close the upper annular
3. Displace the riser to kill weight mud via the boost line.
4. Open the lower annular and permit the gas to migrate to below the upper annular.
5. Circulate kill weight mud at a high flow rate across the BOP via the closest outlets below the upper annular— down the kill line, via the bleed line, and up the choke line.
6. Monitor returns at the surface manifold and MGS, displace a minimum 1½ times the line volume and/or until such time that the gas reading approaches zero to ensure that as much gas as possible is removed from the system. Ensure the liquid seal integrity is maintained and set the alarm appropriately.
7. Monitor the riser level via the trip tank.
8. Once any potential gas has been circulated out of the BOP, confirm alignment of the failsafe valves, slowly reduce the upper annular closing pressure and function the upper annular open.
9. Monitor the riser level status and prepare to close the diverter in the event of gas detection in the riser.
10. Open the lower pipe rams; confirm the well status with a trip tank flow check.
11. Circulate and condition the mud conventionally via the drill string

10.2.2.3 U-Tube Method

The U-tube method can be used as an initial method of removing trapped gas or as an additional action if the high-rate circulating method resulted in high gas levels. This method involves displacing the choke line to a suitable lighter-density fluid and allowing the heavier kill mud weight (KMW) in the marine riser to U-tube into the choke line, where it can be removed by circulating down the kill and taking returns up the choke. The procedure may need to be modified according to subsea BOP stack components and configurations.

1. With the lower annular remaining closed, isolate the wellbore with the lower pipe ram.
2. Displace the kill line with KMW, taking returns up the choke line via upper choke outlet
3. Continue circulation until the choke and kill lines are full of uncontaminated KMW

4. Close the upper annular.

5. Equalize and open the lower annular to allow any residual gas to migrate upwards below the upper annular

6. Circulate KMW down the kill line and up through the gas bleed line

7. Establish the U-tube by displacing the choke line to inhibited water (WBM) or base oil (SOBM) down to the BOP stack, taking returns up the kill line. Do not over displace.

Note: Limit the displacement volume such that the differential pressure across the annular does not exceed 500psi.

8. Close the failsafe valves on the kill line.

9. Vent the choke line to the MGS. This will allow the water/base oil and depressurized gas to unload to the MGS.

10. Open the upper annular preventer and allow KMW to U-tube from the marine riser into the choke line, while continuously filling the riser with KMW.

11. Close the upper annular preventer and displace the choke line with KMW through the kill line.

12. Flow check the well through the choke

13. Open the upper annular and flow check to ensure the well is static

14. Circulate and condition the mud conventionally via the drill string

10.2.3 Vessel Motion

Vessel heave alternately lengthens and shortens the drilling riser and can make the well appear to flow. In extreme cases, it can cause an apparent loss of returns by exceeding the surge capacity of the shale shaker. Vessel pitch, roll, and heave can cause changes in pit level and can make kick detection difficult.

Wear on BOP or Diverter Sealing Elements—Pipe movement through a closed BOP or diverter can cause wear of the sealing elements. Wear on sealing elements can be minimized by:

a) Adjusting the system closing pressure to the lowest pressure that results in an acceptable closing time,

b) Hanging off the drill pipe as soon as practical after a kick has been identified,

c) Reducing the closing pressure to the lowest practical value during sustained periods of pipe motion, and

d) Adjusting the motion compensator.

Floating drilling rigs with a subsea BOP stack use ram locking devices. These locks may operate fully automatic, semi-automatic, or independently. A procedure should be developed to instruct the user on how to reduce pressure to minimize wear when the BOPs are closed on drill pipe. Specific recommendations as to closing pressures should be obtained from equipment manufacturers.

10.3 Subsea Exceptions to Well Control Procedures

10.3.1 General

The well control techniques discussed under Section 9, “Well Control Procedures—Surface BOPs,” apply to subsea operations with the following special considerations:

a) Choke line pressure loss,

b) Establishing circulation,

c) Low fracture gradients in deepwater,

d) Shut-in and hang-off operations.

10.3.2 Choke Line Pressure Loss

The choke manifold on a surface BOP installation is located close enough to the BOP stack that the pressure loss in the choke line can be neglected for most installations. The pressure at the choke manifold can be considered the wellhead pressure. In subsea stack applications, this is not the case. The pressure loss in the choke line imposes a significant backpressure on the wellbore (refer to 4.13.1). This pressure loss can be reduced by taking returns through both choke and kill lines or reducing the circulating rate. Whichever method is used, it is imperative that correct drill pipe pressure is maintained to hold the correct bottom-hole pressure. If the circulating rate is reduced, it is necessary to have pre-determined the circulating system pressure loss for the reduced rate.

In deepwater wells, at least two, and preferably three, slow circulating rates and pressures and the corresponding choke line pressure losses should be determined. The pressure loss in the choke and kill lines can be determined by circulating down the line (refer to 4.13.1 and 4.13.2 for more detail).

10.3.3 Establishing Circulation

To establish circulation with a subsea BOP stack while maintaining constant bottom-hole pressure, it is necessary to reduce the surface choke line pressure by an amount equal to the choke line friction loss while bringing the circulating pump up to speed.

If the static kill line, or subsea stack pressure sensor is used to monitor casing pressure, the choke should be used to keep the static kill line pressure constant while bringing the pump up to speed. If the kill line pressure cannot be monitored, and no subsea stack sensor is available, the choke line pressure should be reduced by the previously measured choke line pressure loss while bringing the pump up to speed.

Clean drilling fluid should be circulated through the choke and kill line at regular intervals to prevent fluid from gelling. This enables accurate pressure monitoring and prevents pressure surges when breaking circulation.

10.3.4 Fracture Gradients

Experience in deepwater has shown that low formation breakdown pressures can be expected. The basic cause is that a substantial part of the overburden is water. To avoid formation breakdown, it may be necessary to circulate out a kick at a very slow rate.

10.4 Special Subsea Procedures

10.4.1 Marine Riser Release During Well Control Event

Planned Release—If time and weather conditions permit, the following is an example outline of a procedure to release the drill string before the well is killed. Specifics of each rig and operation will vary and should be planned well before operations begin. The following procedure requires that the well was shut-in in accordance with section 9 and the drill string is hung-off on a pipe ram.

1) Displace the drill string with kill weight fluid.

2) Bleed-off the drill pipe pressure.

3) Pick up the weight of the drill string from the closed pipe ram supporting it.

4) Close the annular preventer and adjust the closing pressure so the tool joints may be stripped into and out of the annular preventer. Open the pipe rams.

5) Strip out enough drill pipe to reach the joint that was hung in the ram preventer (refer to 10.4.3).

6) Install the rig's subsea preventer hang-off tool or loosen the tool joint of the landing joint if a hang-off tool is not available.

7) Strip the drill string back into the hole to place the hang-off tool or loosened tool joint immediately above the closed annular preventer.

8) Close the hang-off ram, bleed the pressure between the preventers, and open the annular preventer.

9) Lower the drill string, landing the hang-off tool or loosened tool joint on the hang-off ram.

10) Release the hang-off tool or back-out the loosened tool joint above the hang-off ram.

11) Close and lock the blind shear rams above the hang-off tool or broken-out tool joint.

12) Close the choke lines; close and lock the applicable pipe rams.

13) Recover the drilling fluid in the riser, pull the remaining drill string, and release the riser.

Emergency Release—If weather conditions or other well problems prevent the above procedure, an emergency release may be performed per the following general outline:

Emergency Disconnect Sequence:

- The EDS system is normally used. The sequences will vary depending on the installed equipment and operational requirements.

Manual Release:

- Hang-off as described in 10.4.3.
- Displace the drill string with a kill weight fluid.
- Bleed off the drill pipe pressure.
- Shear the drill pipe using the blind shear rams and leave the shear rams closed and locked.
- Release the lower marine riser package.

10.4.2 Kick with Drill Pipe Out of Hole

If a well begins to flow when the drill pipe is out of the hole, following is an outline of a procedure that can be used to regain control:

- At the first indication of the well flowing, close the blind rams, open the gate valve on the subsea BOP stack to a closed choke line at the surface (i.e., a hard shut-in), and record the shut-in pressure. A 0-500 psi gauge is recommended to detect small pressure changes (refer to 4.8.1). Record the kick volume.

  If the choke line is filled with a fluid other than what is in the well, it should be taken into consideration when performing the shut-in casing pressure calculations.

- Verify well has stopped flowing. If well appears to continue to flow, there may be gas in the riser. Refer to section 10.4.4 (Gas in the Riser).

- If flow has stopped and there is no gas in the riser, run the drill string in the hole to the top of the BOPs. Install an IBOP.

- Add the hydrostatic pressure of the fluid in the choke line to the surface pressure to determine the pressure below the blind rams.

- Determine if the pressure below the blind rams can be overbalanced by hydrostatic pressure of the drilling fluid that can be safely contained by the riser. If so, adjust the riser tensioners to support the additional drilling fluid weight and displace the drilling fluid in the riser with drilling fluid of the required density.

- When running in the hole the influx can elongate due to drill pipe displacement which can change the hydrostatic pressure in the well. Ensure to compensate for this reduction in pressure when calculating the riser cap density.

- Close the diverter. Open the BOPs and watch for flow.

    i. If the well does not flow, open the diverter and run in the hole.

    ii. If the well starts to flow, close the blind ram preventer, displace the choke and kill lines with heavy drilling fluid, and circulate until the riser contains drilling fluid of the desired density.

- Continue going in the hole. As drill pipe is run in the hole, lighter mud weight will be displaced into the riser. Stop periodically as per the well control plan and circulate the riser to remove the lighter fluid and maintain the required drilling fluid density.

- Once reaching the bottom of the well, shut-in the well and begin killing the well using a constant bottom-hole method.

10.4.3 Close-in and Hang-off Operations

To minimize wear on the annular BOP sealing element, to be prepared for an emergency disconnect, or to minimize trapped stack gas, the drill string can be hung-off on a pipe ram BOP after a kick is shut-in.

1. Stop drilling (if applicable), shut down the drilling fluid pumps, and perform a hard shut-in with the annular BOP while sounding the alarm.

2. Observe the casing pressure. If the casing pressure will exceed the allowable level, follow the pre-selected contingency plan (refer to 7.4.5).

3. Adjust the closing pressure on the annular preventer to permit stripping of tool joints. (Refer to 12.8 for stripping operations). Confirm space-out by stripping through the annular to locate tool joint.

Note: Confirm hang-off capacity of desired pipe ram is sufficient for string load

4. Hang-off the drill pipe on the desired pipe ram as follows:

    i. Position a tool joint above the hang-off rams.

    ii. Close the hang-off rams.

    Note: Reducing the closing pressure of the pipe rams can help prevent damage to the rams while stripping.

    iii. Carefully lower the drill string until the tool joint rests on the hang-off rams. If closing pressure was reduced for stripping, increase pressure to recommended operating pressure for hang-off.

If using a motion compensator, reduce support pressure on the motion compensator so it will remain in tension to aid shearing.

5. Allow the shut-in pressure to stabilize and record pressures.

6. Determine the volume of the kick.

7. Calculate the drilling fluid density required to kill the kick (refer to 9.6.2).

8. Kill the well using a constant bottom hole method.

9. Check rig crew duties and stations.

10. Review and update output and hole volume data and complete the well control worksheet.

11. Inspect the BOP stack with ROV.

10.4.4 Gas in the Riser

Refer to the IADC Drilling Manual, Riser Gas Handling guidelines.

11 Well Control Procedures—Recommended Rig Practices

11.1 Well Control System Equipment Installation

On drilling rigs, a schematic drawing should be available on the rig showing all system components, equipment sizes, and equipment locations, including the location of the main control panel and remote panel(s). Well completion and well service operations schematics should also be available on the rig during these operations.

11.2 Well Control Equipment Installation Test

All well control system components shall be inspected and tested in accordance with API 53.

11.3 Crew Drills

11.3.1 General

All concerned personnel should be familiar with the well control system components and installation and capable of reacting quickly and efficiently to potential situations requiring their use. Drills should be documented, executed, repetitive, and followed up to correct identified problems.

Drills may or may not be announced in advance. Drills generally enhance the crew proficiency in well control situations. The drill should be repeated on a daily basis until each crew shuts-in the well within the specified competency assurance program time. Thereafter, the drill should be repeated weekly to maintain proficiency.

The following drills, frequency, and proficiency levels are considered desirable for drilling operations.

11.3.2 Pit Drills

During a routine operation, the rig supervisor should simulate a gain in pit drilling fluid volume to cause an alarm to be activated if possible. If this is not possible, the drills may be initiated by word of mouth. The drilling crew should immediately initiate one of the four procedures discussed in 11.3.2.1 through 11.3.2.4 below, depending on the operation at the time of the drill. A pit drill is terminated when the crew has completed all of the listed steps. The supervisor initiating the drill should record response time, which should be in accordance with the competency assurance requirements for the drilling contractor and operator.

11.3.2.1 On-Bottom Drill

This drill should be carried out to completion.

a) Signal given.

b) Stop drilling or other operation.

c) Space-out the drill pipe in the BOPs while sounding the alarm.

d) Stop pump and rotating.

e) Check for well flow.

f) Close or simulate closure of the annular preventer

g) Record simulated influx volume and time to secure the well.

11.3.2.2 Tripping Pipe Drill

Tripping drills shall only be performed in cased hole. A full-opening safety valve and wrench for each size and type connection in the string shall be open and on the floor ready for use. Safety valves shall be clearly identified as to size and connection to avoid confusion and lost time when stabbing.

a) Signal given.

b) Stop tripping operation.

c) Position the upper tool joint above the floor and set slips.

d) Stab the drill pipe safety valve on drill pipe.

e) Close the drill pipe safety valve.

f) Close or simulate closure of the annular preventer.

g) Record simulated influx volume and time to secure the well.

11.3.2.3 Drill Collars or Tool Joints in the BOP Drill

Prepare for this operation in advance. Prior to reaching the drill collars or bottom-hole assembly when pulling out of the hole, the appropriate crossover sub must be placed on a single joint of pipe. A full open safety valve is then made-up on the top of the joint of pipe. Flows that occur with drill collars or the bottom-hole assembly in the BOPs are generally quite rapid since they are usually the result of expansion of a gas bubble close to the surface. A joint of pipe picked up with the elevators is usually easier to stab and make-up than a safety valve alone. Under actual kick conditions (other than drill) if only one stand of drill collars or the bottom-hole assembly remained in the hole it is probably faster to simply pull that last stand and close the blind rams.

a) Signal given.

b) Position the upper drill collar or tool joint and set the slips.

c) Stab the drill pipe safety valve made up on one joint of pipe with the appropriate crossover sub onto the drill collars or tool joint.

d) Lower the collars with joint of pipe into the hole and set the slips

e) Close the drill pipe safety valve.

f) Close or simulate closure of the annular preventer (or ram preventer on surface stacks with drill pipe crossover).

g) Record simulated influx volume and time to secure the well.

11.3.2.4 Out of the Hole Drill

a) Ensure nothing is in the hole.

b) Signal given.

c) Close the blind rams or blind shear rams.

d) Record simulated influx volume and time to secure the well.

11.3.3 Stripping Drill

Physical stripping drills are not recommended for standard operations. Stripping drills can be beneficial for some high-risk wells to confirm stripping is possible. As an alternative, a tabletop stripping exercise should be considered. For more information on stripping operations, refer to 12.8.

11.3.4 Choke Drill

With pressure trapped below a closed preventer, use the choke to control casing pressure while pumping down the drill pipe at a prescribed rate. This drill establishes equipment performance and allows the crew to gain proficiency in choke operation. Discharge into a trip tank or pit to accurately monitor flow rates for correlation with choke opening, pump rates, and pressure drops in the circulating system and across the choke. This is particularly important for subsea BOP stacks in deepwater, which may have significant circulating pressure losses in the choke lines.

a) On floating rigs, activate the motion compensator.

b) Shut in the well

c) Apply 500psi to annulus

d) Line up returns through the choke line, to MGS, and to pits (or trip tank)

e) Record SICP every minute

f) Turn on pumps and hold bottom hole pressure constant

g) On floating rig, monitor and record CLFP

h) Compare recorded volumes pumped to returns to ensure they are the same

i) Record lag time

11.3.5 Hang-off Drill (Subsea BOPs Only)

Following prescribed procedures, the crew should place the drill string in position for hang-off. One hang-off should be made before drilling out of surface pipe to ensure that all necessary equipment is on hand and in working condition. Actual hang-off is not normally performed on subsequent drills. This drill can be conveniently performed in conjunction with the pit drill.

11.3.6 Diverter Drill (Gas in Riser)

Only required for subsea BOPs with marine drilling risers. Performed immediately after a well has been secured on a pit drill.

a) Monitor riser on the trip tank

b) Simulate flow from the riser

c) Close diverter and sound the alarm

d) Ensure downwind diverter overboard valve is open

e) Record total drill time.

11.3.7 Diverter Drill (Shallow Gas or Shallow Water Flows)

Only required for surface stack (land and offshore). For land rigs, a decision should be made as to whether or not to keep circulating after diverter closure. If the driller is required to leave the drill floor, the pump should be shut down to prevent damage and the ESD should be activated.

a) Close diverter and sound the alarm

b) Ensure downwind diverter overboard valve is open

c) Simulate lining up the pumps to circulate either kill mud, seawater, or other available drilling fluid

d) Essential personnel go to duty stations

e) Non-essential personnel muster according to emergency plan

11.3.8 Recommended Frequency of Drills

Drill Type	Surface Stack Frequency	Subsea Stack Frequency
Pit Drills	Every 7 days	Every 7 days
Choke Drills	Once per well prior to drilling out surface casing shoe	Before drilling out each casing shoe, and prior to drilling through expected hydrocarbon bearing zone
Hang-off Drills	N/A	Prior to drilling through expected hydrocarbon bearing zone
Diverter Drills	Before drilling top section	Before drilling first intermediate casing

11.4 Trip Tanks

A trip tank is a low-volume, calibrated tank, which can be isolated from the remainder of the surface drilling fluid system and used to accurately monitor the volume of fluid going into or coming from the well. The primary use is to measure the amount of drilling fluid required to fill the hole while tripping pipe to determine if drilling fluid volume matches pipe displacement.

Other uses include measuring drilling fluid or water volume into the annulus when returns are lost, monitoring the hole while logging or following cement job, and calibrating drilling fluid pumps. A trip tank may be any shape if it is calibrated accurately and a means is provided for reading the volume contained in the tank at any liquid level. The readout can be direct or remote, preferably both. The size of the tank and readout arrangement should be such that volume changes on the order of one-half barrel can be easily detected.

Tanks containing two compartments with monitoring arrangements in each compartment are preferred as this facilitates removing or adding drilling fluid without interrupting rig operations. Measurement of drilling fluid volume and flow rate is critical in all operations. It is more difficult to measure in floating operations. In floating operations, pit level monitoring devices (floats) should be in the center of the pits or multi-floats with sequential integration utilized. A trip tank and pit watcher should be considered if vessel movement creates any problem in measuring drilling fluid levels on trips.

11.5 Gas-Cut Drilling Fluid

Gas-cut drilling fluid can occur during drilling operations. Gas cutting of the drilling fluid column causes relatively small reduction in hydrostatic pressure. The reduction in hydrostatic pressure is illustrated in the chart shown in Figure 11.1. This reduction in hydrostatic pressure is normally not a severe problem except where the casing seat is shallow; therefore, increasing mud weight may not be required. However, other issues can occur such as:

a) reduction in the efficiency of the mud pumps

b) mud pump damage

c) wellbore/riser unloading resulting in drilling fluid discharge on the drill floor

Gas-cut drilling fluid and foaming can create misinterpretation by giving an indication of pit volume increase (i.e., a kick) even when there is no flow into the wellbore. For proper well control, drilling systems should be equipped with mud-gas separators and degassers to minimize recirculation of gas-cut drilling fluid. Use of a pressurized drilling fluid balance and defoaming agents are also recommended. Refer to API 53 and API 16C for more information on mud/gas separators and degassers.

Note: Gas-cut drilling fluid or foam can occur independent of each other

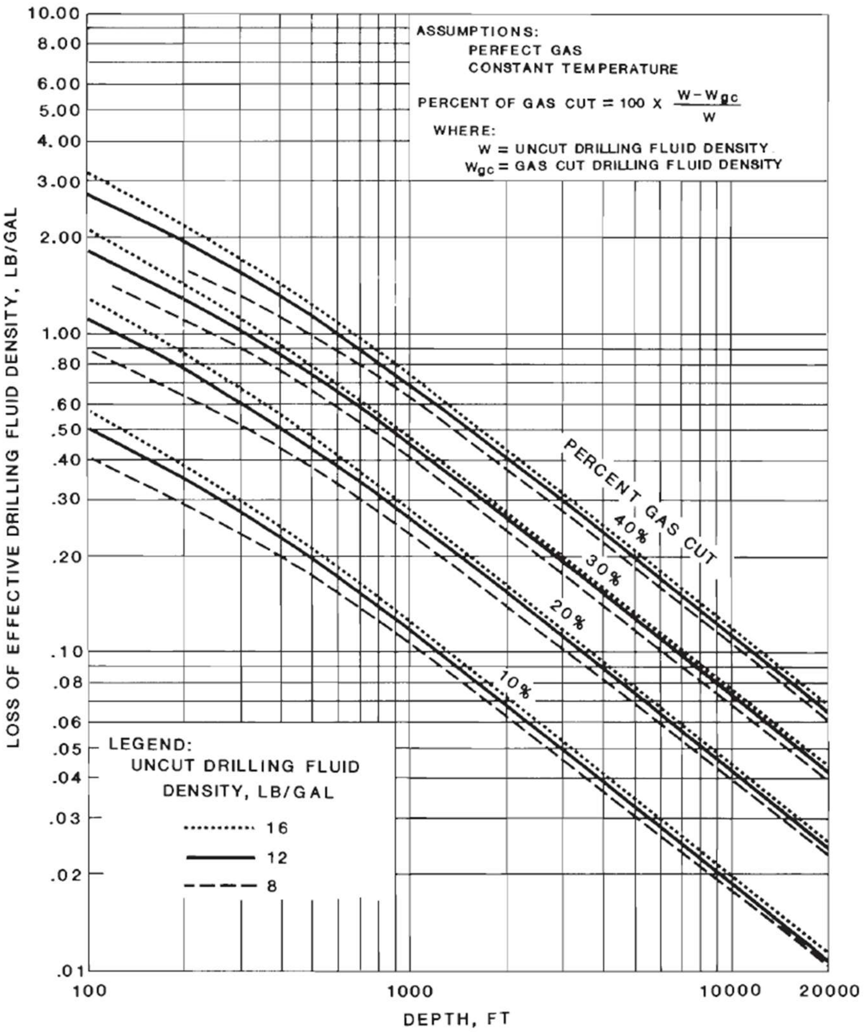


Figure 11.1—Loss of Effective Drilling Fluid Density Due to Gas Cut

11.6 Trip Sheet

A trip record shall be maintained showing the volume of drilling fluid required to fill the hole after a specified number of stands are tripped out the wellbore or displaced volume when tripped in of the wellbore. The record shall include the calculated displacement volume, the actual volume used, and the cumulative volume. The difference between the calculated and actual volume should be recorded and the cumulative volume trended to help identify any well issues.

Trip Sheets should be kept (hard copy or digital) to compare with previous trips and available to the driller. Table 11.1 illustrates an example trip sheet that could also be used in a spreadsheet format in a computer.

11.7 Pre-Kick Information

11.7.1 General

Detecting a kick faster helps reduce the influx volume. Timely kick detection, control, and response requires the collection of specific pre-kick information. This section identifies the key information that should be collected.

11.7.2 Formation Integrity

Following the cementing of each casing string and drilling out the shoe, a formation integrity test or a leak-off test should be conducted to determine if the formation can support the maximum required hydrostatic pressure.

Note 1: Either test can be repeated as the well is drilled to maintain reliable information.

Note 2: Formation integrity tests and leak-off tests are not synonymous (refer to 4.7, 4.7.1, and 4.7.2).

11.7.3 System Pressure Losses

While drilling, at tour change or after a significant change in the circulating system pressure, the pressure drop (slow circulating rate pressure) throughout the circulation system should be obtained and recorded on the recommended well control worksheet and the tour report. The pump rate used to obtain this pressure drop should be the range of reduced rates that would be used to circulate a kick from the well on each pump. The slow circulating rate pressure should be recorded using the same gauge used during well control operations.

Note: A significant change in circulating system pressure can be caused by a change in depth, mud rheology, wellbore geometry, BHA, etc.

11.7.4 Capacities—Displacement

Drilling fluid tank capacities and volumes should be determined for both the entire surface drilling fluid system and individual tanks. The capacities of tubing or drill pipe, tool joints, drill collars, marine riser, casings, wellbore, and choke and kill lines should be calculated and tabulated.

The annular volume between any possible combination of pipe/pipe, pipe/hole, and service tool/hole/pipe should be calculated and tabulated. Displacement of the pipe string (tubing, casing, drill pipe, drill collars, regular stabilizers, service tools, etc.) should be calculated and tabulated at intervals and maintained at the rig for ready reference in the event of a kick.

Note: Capacity refers to a volume per length factor

11.7.5 Pressure Limitations of Installed Components

The maximum allowable pressure that can be applied against each component within the well control system should be documented on the kill sheet.

11.7.6 Drilling Fluid Pumps

The volume per stroke output for each pump should be obtained and entered on the kill sheet.

11.7.7 Drilling Fluid Mixing Capability

The rig's actual maximum efficient rate of mixing drilling fluid should be determined. This mixing rate and its effect on drilling fluid properties should be used in planning well control operations.

11.7.8 Wellbore Geometry

The well's True Vertical Depth (TVD), Measured Depth (MD), casing depth, and gauge hole size should be recorded.

11.7.9 Planned Mud Weight

The planned mud weight for each section should be recorded on the kill sheet.

11.7.10 Subsea Pre-Kick Information

In addition to sections 11.7.1 to 11.7.9, for subsea wells, the water depth, choke and kill line inside diameter and length, and riser length and bore, and Choke Line Friction (CLF) pressure at the SCR should be recorded.

11.8 Post-well Kill

11.8.1 Post-kill Information

Following the well kill, a safe trip margin and drilling fluid density should be determined and then recorded on the kill sheet. The drilling fluid density should be sufficient to permit safe withdrawal of the drill pipe from the hole based on swab and fracture considerations.

11.8.2 Post-kill Trip

Depending on the specific well's risk assessment, it can be beneficial to trip out of the hole to ensure the wellbore was not adversely impacted by the kick. The post-kill trip may be a short trip or a full trip out. Alternatively, drilling ahead may be an option.

11.9 Minimize Time Out of the Hole

Time with pipe out of the hole should be minimized. Necessary crossover connections should be available when running service tools that can interfere with closure of the rams in the BOP. Having the proper connections available ensures that pipe movement can be accomplished in order to close more than the annular BOP.

During drilling operations, in case of extended time out of the hole, the pipe should be run back to the last casing shoe if possible. In well servicing operations the pipe should be run to a sufficient depth to ensure that the well can be controlled. In both situations a pipe heavy condition should be maintained.

11.10 Trip Margin

The use of a trip margin is encouraged to offset the effects of swabbing. The additional hydrostatic pressure permits some degree of swabbing without losing primary well control.

11.11 Short Trip

A short trip typically involves pulling between five stands and the entire open hole section. A short trip and circulating "bottoms-up" before pulling out of the hole can also be used to determine the system's swabbing characteristics.

Table 11.1—Example Trip Sheet

Well Name ____
Date __________ Drilling Fluid Density _____________
Depth ___________________ DP Size _____________
Time Trip Started _________ DC Size _____________

Trip No. _________________________________
Fluid Loss ________________________________
DP Displacement __________________________
DC Displacement __________________________

			DISPLACEMENT				
No. of Stands	Theoretical		Last Trip		This Trip		Comments
	Per ___ Std	Total	Per ___ Std	Total	Per ___ Std	Total	

11.12 Rig Practices for Handling Pressure

11.12.1 General

The well planning process should consider whether a well might flow as a result of the operations (refer to Section 7, Well Planning). This process should include well drilling, completions, and plug and abandonment operations.

11.12.2 Barriers to Flow

Two barriers shall be used after a competent shoe is established.

Barriers to flow include:

1) Drilling or workover fluid hydrostatic head plus any applied surface backpressure;

2) Blowout preventers or safety valves;

3) Mechanical plugs such as bridge plugs or wireline plugs;

4) Cement or barite plugs.

11.12.3 Other Practices

Some rig practices for handling pressure in certain situations are listed below:

— A spare surface safety valve should always be on the rig floor.

— An inside BOP, drill pipe float valve, or drop-in valve should be available on the rig floor when stripping in or out of the hole. Crossovers of the proper size and thread design for any pipe in use should be available.

— If possible, avoid setting retainers, bridge plugs, packers, etc., high in the hole. Under certain conditions, pressure can accumulate below that might be difficult to control without snubbing equipment.

- Consider the possibility of higher pressures below a bridge or fish in the wellbore when washing over or drilling through it.

- Never back-off high in a stuck string during a well control problem without first setting a plug or backpressure valve in the bottom of the stuck string.

- Some blowouts have occurred during coring operations. If the core barrel plugs and it is not possible to circulate, take special care not to swab the well in when pulling out of the hole. If there is a kick, do not attempt to pull out of the hole.

11.13 Rig Practices for Pipe Handling

In addition to testing and maintenance of BOP equipment and controls, the pipe run in the hole should be properly designed, inspected, and maintained. The stress of bending and rotating through doglegs in the hole, torsional stress, collapse and internal stress, joint integrity, wear, hydrogen sulfide exposure, and corrosion/erosion are factors affecting drill pipe, drill collars, tubing, casing, and liners that may be run in the hole. Pipe should be designed, maintained and inspected as per the following:

- Drill Stem Pipe and Components—API RP 7G, *Recommended Practice for Drill Stem Design and Operating Limits* (reader should check for the latest edition) covers all aspects of drill stems: kelly, tool joints, drill pipe, and drill collars.

- Casing and Tubing—API RP 5C1, *Recommended Practice for Care and Use of Casing and Tubing* which covers storage, transportation, handling, and reconditioning of casing and tubing.

- Manufacturer’s maintenance and inspection requirements if applicable

11.14 Drill Stem Tests

Drill stem test procedures should include requirements to mitigate the associated hazards. A risk assessment shall be conducted to identify and mitigate well control risks and include these hazards and precautions.

Hazards associated with Drill Stem Testing include:

a) Potential leaks in the drill string components which are typically not designed for well testing

b) Flowing the well to surface (e.g., rig floor) which can result in the release of hydrocarbons and create the potential for an explosive environment

c) Loss of control of the well resulting in a blow-out

d) Using non-production grade equipment for flowing the well

e) Improper connection makeup of piping

f) Corrosive fluids in the drill string and components

g) Radiant heat from flaring operations

Precautions for Drill Stem Test should include:

a) Use gas detectors in work areas where drill stem testing equipment is installed

b) Use of a cascade system if H2S or CO2 are expected

c) Use of a water curtain/shielding for flaring operations

d) A containment philosophy to address surface leaks

e) A method to secure the well if a leak develops

If a leak develops below the BOP, the appropriate preventer should be shut. If a leak develops above the BOP, a shear ram and open hole sealing device (if installed) can be used to secure the well, or the well can be bullheaded depending on the rate of the leak.

Special precautions should be taken for drill stem tests under high pressure or sour gas conditions. Refer to API RP 7G, *Recommended Practice for Drill Stem Design and Operating Limits* and API RP 49, *Recommended Practice for Safe Drilling of Wells Containing Hydrogen Sulfide* (reader should check for the latest editions) for special precautions if a possibility of hydrogen sulfide exists for drill stem testing under critical high pressure.

12 Procedures for Well Control Complications

12.1 Introduction

Well control operations can be complicated by equipment failure, formation breakdown, improper operating procedures, or human factors. Normal well control operations can be escalated by these complications.

This section outlines procedures that can be used to minimize or solve many well control complications. The following are included in this discussion.

a) Pump failure

b) Excessive casing pressure

c) Well kick while running liner or casing

d) Well kick during cementing operations

e) Parted or washed-out drill stem

f) Stuck or packed-off drill stem

g) Plugged or packed-off bit

h) Gas-cut drilling fluid

i) Gas influx in cemented annulus

j) Procedures for gas bubble migration

k) Drill Stem Testing

l) Stripping procedures

Traditional indicators for problems while circulating out a kick are shown in Table 12.1.

Table 12.1—Indicators of Possible Problems while Circulating Out a Kick

Major Indication
Larger
Arrow ⬇

Other Indication
Smaller
Arrow ↓

	Drill Pipe Pressure	Casing Pressure	Drill String Weight	Pit Level	Pump SPM
Choke Washes Out	⬇	⬇		⬆	↑
Gas Reaches Surface	⬇	⬇	↓	⬇	
Loss of Circulation	⬇	↓	⬆	⬇	↑
Hole in Drill String	⬇				↑
Pipe Parted	⬇		⬇		↑
Bit Nozzle Out	⬇				↑
Pump Volume Drops (Pump Damage Ñ Gas Cut Mud)	↓	↓			↑
Gas Feeding In		↑	↑	⬆	
Choke Plugs	⬆	⬆			↓
Bit Nozzle Plugs	⬆				↓
Hole Caved In	⬆		Stuck	↓	↓

12.2 Pump Failure in a Kick Situation

12.2.1 General

Pump failures can cause erratic drill pipe pressure surges, pounding noises, or erratic movement of the rotary hose. The following paragraphs outline pump problems and some recovery methods if the problems occur during a kick.

12.2.2 Partial Pump Failure

A partial pump failure can reduce fluid delivery. It is indicated by a decrease in pump pressure, an increase in pump stroke rate, and erratic rotary hose movements. Some of the symptoms of partial pump failure might also be caused by a drill stem washout, bit jet washout, washed out choke, or gas-cut drilling fluid.

If partial pump failure is found to be the problem, and no standby pump is available, circulating may continue with the partially effective pump. A new reduced circulating pressure should be determined.

12.2.3 Severe or Total Pump Failure

If the pump failure is severe or total, and another pump is not available, the well can be controlled with the volumetric method.

12.3 Excessive Casing Pressure

12.3.1 General

Mechanical failure or formation breakdown can result from excessive casing pressure during initial closure or while circulating out a kick. Mechanical failure of the casing at the surface or of the BOP and related well control equipment can result in loss of well control. Formation breakdown can lead to loss of circulation, an underground blowout, and/or possible broaching to the surface. If the casing pressure exceeds the maximum allowable casing pressure, steps should be taken to prepare for lost circulation. The choke shall not be opened to reduce casing pressure.

Note: Opening the choke can result in additional influx due to reducing the bottom hole pressure

12.3.2 Design Considerations

The casing string design, equipment selection, and testing of surface equipment, should be designed to prevent mechanical failure at surface. The system should be designed to ensure formation fracture in preference to mechanical failure at the surface, since this would result in uncontrolled release at the surface. The consequences of formation fracture while closing-in or circulating out a kick can result in an underground blowout that can broach to the surface (refer to 4.14 and 7.3).

12.3.3 Alternatives If MAASP Is Reached at Close-In

If the casing pressure increases to the maximum allowable annular surface pressure (MAASP) during initial closure, a decision shall be made as to whether the well should be killed by conventional circulation methods, or whether alternative methods should be implemented. The well control contingency plan (refer to 7.4.5) should be consulted and one of the following alternatives should be considered:

a) Flowing the well under controlled conditions until a dynamic kill can be performed;

b) Bullheading;

c) Sandwich kill.

Note: Opening the choke can result in additional influx due to reducing the bottom hole pressure.

12.3.4 Alternatives If MAASP Is Reached While Circulating a Kick

The alternatives are:

a) Continue circulation of the kick with drill pipe pressure control while allowing the casing pressure to increase; or

b) Close-in the well and bullhead (refer to 4.11.1) the kick back down the annulus to reduce casing pressure or spot a heavy pill of drilling fluid, barite, or cement (refer to Section 13 and its subparagraphs)

c) Perform volumetric method to bring gas to surface and kill using lubricate and bleed if water-based fluid is in use

12.3.5 Possible Consequences

The alternatives listed above have the following possible consequences:

a) Allowing the casing pressure to increase can lead to mechanical failure or formation fracture.

b) Closing-in the well, bullheading, or spotting a heavy fluid pill can cause formation breakdown.

c) If formation fracture occurs and only a small amount of casing has been set, the possibility of broaching to the surface exists.

12.3.6 Handling Excessive Casing Pressure

If the casing pressure exceeds the rating of the surface equipment, the possibilities of surface equipment failure, or broaching to the surface should the formation or casing cement job break down, exist. Alternatives include pumping a barite plug (refer to 13.4), pumping cement slurry (refer to 13.5.3), or allowing the well to flow until the pressure is reduced and a dynamic kill can be performed.

If the surface equipment rating will not be exceeded and casing is set to a depth where broaching to the surface is not likely, consideration can be given to closing the well and allowing an exposed formation to fracture, or to create conditions which cause formation fracture by bullheading fluid down the annulus (refer to 4.11.1). This operation can cause an underground blowout, as discussed in 13.3.

12.4 Pipe Problems with a Well Kick

12.4.1 General

Pipe problems can complicate dealing with a kick. This section addresses several potential problems: running casing, running a liner, parted drill pipe or tubing, holes in drill pipe or tubing, and stuck pipe.

12.4.2 Running Liner

Well kicks that occur while running a liner can generally be handled in the same manner as a kick that occurs while drilling. If the liner is near bottom, an attempt should be made to strip it to bottom in order to kill the well (refer to 12.8 and its subparagraphs for recommended stripping procedures). The influx can then be circulated out, the drilling fluid conditioned, and the liner cemented in place or otherwise installed.

If unable to strip to bottom while running the liner inside the casing and the bottom of the liner is not as deep as the casing shoe, an attempt should be made to strip the liner to the casing shoe but not into open hole below the shoe.

In some cases, the annulus pressure can often be reduced by bullheading heavy drilling fluid to overbalance the pressure (refer to 4.11.1 for the recommended procedure). This can permit opening the BOPs temporarily. Running pipe into the well under these conditions displaces part of the heavy drilling fluid and can start the well flowing again.

Pumping high density drilling fluid into the annulus, by either circulating or bullheading, can cause or aggravate lost circulation below the casing shoe. These effects can create additional well issues as opposed to being able to conduct stripping operations with less or no pressure on the annulus.

12.4.3 Running Casing

Prior to running casing, the following pre-checks should be performed:

a) Confirm the annular packing element is correct for the casing size in use

b) Confirm closing pressure for annular is in accordance with OEM recommendations to seal off the casing in use without damaging or collapsing the casing

c) Note: Adjustments to pressure can be needed to allow for distance or elevation changes from closing unit or other site-specific conditions

d) Confirm the packer is compatible with current well conditions (e.g., temperatures, fluids, pressures)

e) If running casing conventionally, confirm a circulating swage with FOSV is ready on the drill floor

f) If running casing with a Casing Running Tool (CRT), confirm that a special rig down device is available, consisting of a crossover from the casing to FOSV and back to a casing pup is needed to allow CRT weight transition and rig down

g) Confirm snubbing force calculations to aid in identifying pipe light conditions

h) Refer to a well interval surge model to determine maximum casing running speed to avoid formation breakdown

While running casing, the following should be monitored:

- Use trip sheets to monitor casing and displacements while running in the hole

If a kick is taken with the casing off bottom, a determination should be made on the next steps. This can be a non-circulating method, bullheading, or stripping to bottom. Considerations are distance to bottom, well control equipment installed (i.e., redundant closure device sized for casing), wellbore geometry, availability of mud, stripping pressure, etc.

- When filling the casing with mud or bullheading, monitor the casing pressure for pipe light conditions, and collapse conditions

Prior to stripping to bottom, the following information should be confirmed:

- Confirm stripping pressure for annular is in accordance with OEM recommendations to strip the casing in use without damaging the casing

Gas entering the casing can migrate upward if the gas migration rate exceeds the pump rate and complicates maintaining constant bottom hole pressure since drill pipe pressure varies. One mitigation is to increase the pump rate to exceed the gas migration rate if possible. If increasing the pump rate is not desirable due to increased ECD and risk of fracturing the formation, then the volumetric method should be used.

Note: The annulus should be controlled first with the volumetric method since the gas will reach surface quicker due to the reduced annulus clearance.

Dangers of lost circulation and an underground blowout are much greater while running casing due to the small annulus area. The reduced annulus area leads to increased ECD due to increased pump rate and higher annulus casing pressures due to gas bubble expansion, which can fracture the formation.

If unable to kill the well with conventional methods, well control experts (internal or external) should be consulted to employ non-conventional well kill methods.

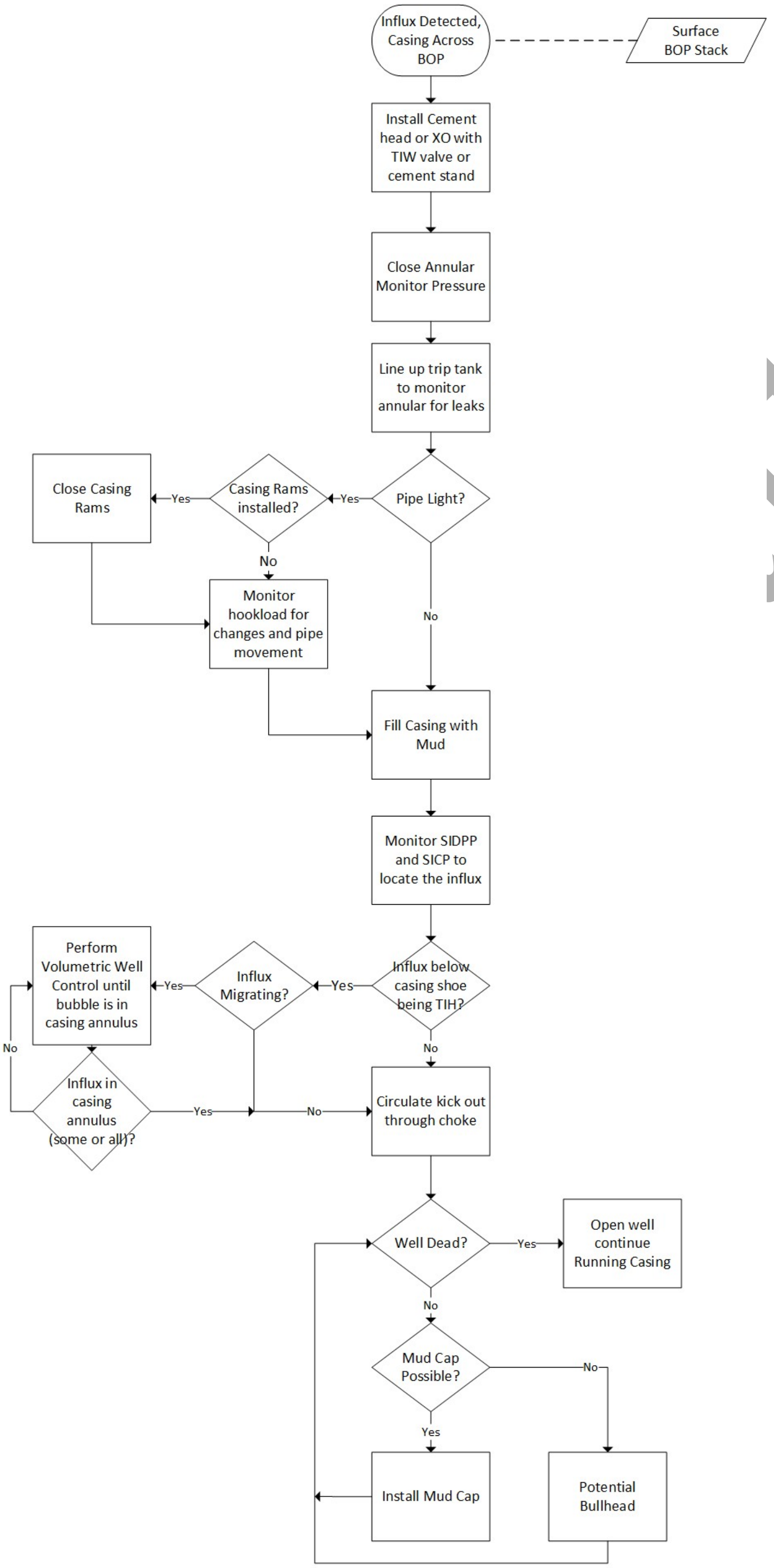


Figure 12.x – Well Control for Running Casing

12.4.4 Parted or Washed-Out Pipe in the Hole

Indicators of a washout or parted drill pipe are:

1) An increase in pump stroke rate

2) A decrease in pump pressure

3) A loss of string weight

Pipe should not be tripped out of the hole if there is any indication of a well kick.

12.4.5 Procedures for Parted or Washed-Out Pipe While Circulating Out a Kick

If the drill stem has developed a washout, consideration should be given to preventing washout enlargement and failure of the weakened section. Drilling fluid circulation, pipe movement, and string rotation should be done carefully to minimize chances of the drill stem parting. With the aforementioned exceptions, procedures for removing the influx fluid and killing the well are the same for a parted drill stem, drill stem washout, or when the bit is off-bottom and cannot be successfully stripped back to bottom. The following procedures are recommended.

1) Determine the location of the washout. If the drill stem has a washout, its location can be estimated by circulating a marker or lag time associated with choke manipulation. If the drill stem has parted, location of the break can be estimated by using current drill stem weight versus weight prior to parting. If the washout is near surface, the consequence of parted pipe and potential pipe light conditions should be considered.

2) Determine the location of the influx. Observe the shut-in drill pipe pressure and casing pressure. If the shut-in drill pipe pressure is not significantly lower than the casing pressure, the influx gas is still below the washout or the bottom of the drill bit (if off-bottom).

3) If the influx is below the washout or bit (if off-bottom), allow it to migrate upward, resulting in increases in drill pipe pressure and casing pressure as the bubble rises. Circulation before the influx moves above the washout serves no useful purpose in removal of influx fluid and can increase danger of losing the BHA. As the gas migrates up the wellbore, it carries trapped pressure and should be allowed to expand in a controlled manner to reduce pressure in the bubble and reduce stress on the wellbore, while maintaining constant bottom hole pressure. Excess pressure should be bled off in a controlled manner to prevent further influx. Refer to 12.5 for suggested procedures for gas bubble migration.

4) When the influx rises above the washout in the drill stem, the shut-in casing pressure will be higher than the shut-in drill pipe pressure. The influx can then be circulated out using conventional well control procedures.

12.4.6 Stuck Pipe in the Hole

An influx of formation fluids and/or increase in annulus pressure can increase the chances of differential sticking. Stopping pipe movement to close the BOPs can cause the drill stem to become stuck. The only preventive measure that can be undertaken is to reciprocate the pipe. Do not rotate the pipe on a closed preventer due to increased risk of the preventer or pipe becoming damaged.

In the event of a well kick, the first consideration should be to control and kill the well. If the pipe becomes stuck, well killing operations should continue after confirming communication between the drill pipe and casing. After the well control operations are complete, pipe recovery operations can be initiated. Refer to 12.2 through 12.6 of API RP 7G, *Recommended Practice for Drill Stem Design and Operating Limits* for recommendations on pulling on stuck drill pipe, jarring, washover, and hook load considerations.

12.4.7 Plugged or Packed-Off Pipe

If the pipe or bit becomes partially plugged, the drill pipe pressure will suddenly increase while constant pumping rate is maintained. Do not open the choke to maintain constant drill pipe pressure, as the resulting decrease in casing pressure will allow more influx fluid to enter the wellbore and make well control more difficult. Allow drill pipe pressure to stabilize and recalculate the SCR/SPR. Determine new ICP and continue to kill the well using the new ICP value.

If pump shut-down was necessary, follow these steps:

a) Compare original shut-in drill pipe pressure to current drill pipe pressure; the difference is the overbalance on the well.

b) Re-determine the shut-in casing pressure by subtracting the overbalance from current casing pressure. This is the new reference casing pressure. Maintain this casing pressure plus a safety factor while bringing the pump back up to the circulating rate.

c) Note: The safety factor is to keep the well slightly overbalanced.

d) Determine the new overbalance by subtracting the reference casing pressure from the current circulating casing pressure. This is the current overbalance on the well.

e) Subtract this overbalance from the current drill pipe pressure to determine the new ICP. This new pumping rate and drill pipe circulating pressure should be used to continue well killing operations.

If the bit becomes entirely plugged, drill pipe pressure cannot be used to maintain constant bottom-hole pressure. If gas migration is present the casing pressure will increase as the influx migrates upward through the drilling fluid to the surface. Volumetric well control should be used to mitigate wellbore pressure. Follow the procedures for gas bubble migration (refer to 12.5).

If the drill pipe or bit is plugged, consideration can be given to running a string shot, perforating to reestablish circulation, bullheading, or other means of establishing circulation. If there is a restriction in the annulus, circulating drill pipe pressure is likely to be erratic.

If the well is packed off, the first consideration should be to control and kill the well. If the drill string is packed off, special techniques should be used depending on the location of the influx. If wellbore integrity is lost the potential for cross zonal communication (underground blowout) should be considered. If kick is above the pack-off bullheading, volumetric, lube and bleed and perforating can be used. If the kick is below the pack-off, bullheading through the string, free pipe to establish circulation, cementing, or other methods can be used.

12.5 Procedures for Gas Bubble Migration

Normal circulation operations for well drilling are not always possible during well control procedures. The volumetric method can be used when the drill string is out of the hole or unable to pump.

Volumetric method operations maintain relatively constant bottom-hole pressure by releasing a measured amount of fluid from the well to allow the influx to expand as the kick moves up the well over an appropriate amount of time. This release of fluid hydrostatic pressure is compensated by allowing the casing pressure to increase by an equivalent amount thereby maintaining bottom hole pressure relatively constant. Accurate pit volume measurement and monitoring are essential.

As any gas migrates up the wellbore, it carries trapped pressure. This will cause the casing pressure to increase, thereby increasing the danger of equipment failure or formation breakdown and lost circulation. This can be prevented by controlled bleeding off small amounts of drilling fluid without allowing the bottom-hole pressure to drop low enough to permit additional influx. The following procedures can be used to estimate the maintenance pressure required to prevent further influx while avoiding excessive casing pressure:

1) Observe the casing pressure gauge while gas is migrating to assure that excessive pressures do not build up.

2) Arrange a choke line so that it can discharge into a device that can be used to measure discharged fluids.

3) Allow the casing pressure to increase a preselected working factor and safety factor above the initial shut-in casing pressure.

Note: The initial pressure increase may occur very gradually, but the pressure increase will occur faster as gas migrates upward.

4) Calculate the minimum pressure increase which must be maintained for each barrel of drilling fluid bleed off using the following equation:

$$\frac{\text{Pressure increase (psi)}}{\text{per barrel vented}} = \frac{MW \times 53.5}{HD^2 - PD^2}$$

Where,

MW = drilling fluid density, lb/gal.

HD = inside diameter of the wellbore at the top of the gas, in.

PD = the outside diameter in inches of the pipe, tubing, or collars at the top of the gas (use 0 if gas is below bit)

5) As the pressure increases, vent small quantities of drilling fluid, but do not allow the pressure to drop below the minimum casing pressure to assure no further influx as calculated below:

Current minimum casing pressure (psi) = Initial shut-in casing pressure (psi) + safety factor + [pressure increase per barrel vented (psi/bbl per calculation in step 4) x total volume vented (bbls)]

6) When gas reaches the surface, if casing pressure continues to rise, another influx can be present and other volumetric methods should be used.

12.6 Gas Influx in Cemented Annulus

Gas influx can occur during and after cementing operations. The primary cause of gas influx is loss of hydrostatic head can be due to:

1) Water separation,

2) Cement dehydration,

3) Poor cement retarder design or performance,

4) Insufficient annulus fill-up,

5) Lost returns during cementing,

6) Channeling

7) Failure to maintain proper hydrostatic hierarchy (i.e., keeping spacers above pore pressure)

8) Cementing with gas-cut drilling fluid, and

9) Swabbing the hole while reciprocating pipe in cementing operations.

Loss of hydrostatic pressure when cement begins to set can allow formation gas to enter the wellbore and migrate through the setting cement, creating channels and further reducing hydrostatic pressure. The BOP stack should not be removed before the cement has reached its minimum compressive strength to achieve a competent barrier and the likelihood of annular gas flow has passed. Refer to API 10B, *Recommended Practice for Testing Well Cements*. Following are practices that can help minimize gas influx in the cemented annulus:

a) Properly designed cement retarders can achieve a uniform set from the bottom of the hole to the top of the cemented section.

b) Proper conditioning of the drilling fluid and wellbore prior to running casing can help minimize lost returns during cementing operations.

c) Proper conditioning of drilling fluids can help minimize gas cutting, bridging, and viscosity problems.

d) Proper design of casing fill-up and float equipment, potential use of DV tools, along with controlled running and reciprocating speeds, can minimize lost returns and swabbing problems in the hole.

e) Use cement slurry with fast transition time (less than 45 minutes), e.g., right angle set cement.

f) No free water.

g) Cement slurry should be designed for minimal fluid loss (less than 50 milliliters).

h) Utilize vendor cement placement hydraulic and casing centralization standoff program for job design

12.7 Drill Stem Testing

Drill stem tests are non-routine, potentially hazardous operations performed to assess the reservoir properties. Drill stem tests are performed by setting a packer above the formation to be tested and allowing the formation to flow. During testing, the borehole or casing below the packer and at least a portion of the drill pipe or tubing is filled with formation fluid. Furthermore, the formation fluid is produced to the drill floor through drill pipe which is not designed to be used as production tubing. Another hazard is that the formation fluid is routed through temporary piping, metering, and measuring equipment. This results in live reservoir fluids being handled on the rig. As a result, increased diligence should be used to monitor for potential leaks.

At the conclusion of the test, the fluid in the test string above the circulating valve is removed with standard well control methods, such as reversing, to return the well to a safe condition. Depending on the length of hole below the packer, type of fluid entry, and formation pressure, the normal drilling hydrostatic overbalance can be reduced or lost. Caution should be exercised to avoid swabbing when pulling the test string because of the large diameter packers.

12.8 Stripping Procedures

12.8.1 General

During operations on a drilling well, producing well, injection well, or sometimes when plugging and abandoning a well it is desirable to avoid loading fluid into the well, requiring tubing, casing, or drill pipe to be run or pulled while wellbore pressure is controlled by the BOPs. Such practice is called stripping.

During drilling operations, stripping is normally considered an emergency procedure to position the pipe in the well as desired while maintaining constant bottom hole pressure to conduct ongoing well control operations. For the equipment considerations of stripping operations, refer to API 53.

12.8.2 Preparation

Preparation for stripping operations should begin during well planning. When rigging up the BOP stack and trip tank, the following should be considered:

1) An adjustable choke to bleed drilling fluid into the trip tank

2) Stripping schedule (e.g., displacements)

3) Tool joint length and outside diameter, distance from the rotary table to the preventers, and other details that might be needed should be recorded

12.8.3 Stripping Operations

Before beginning to strip, some type of IBOP shall be installed in the drill string. Pipe should be run slowly and an amount of drilling fluid equal to the capacity and displacement of the pipe should be bled as the stand is lowered to avoid excessive pressure build-up. Well pressure should be monitored continuously throughout the stripping operation to ensure adequate bottom hole pressure is maintained and avoid excessive annular pressure.

Stripping should be performed through the annular preventer and requires that the effective string weight be greater than the upward force of the well pressure acting on the cross-sectional area of the tool joint. In some cases, the pipe body can move through the preventer but the tool joint will not because of the greater upward force exerted on the larger cross section. Snub force calculations should be made prior to stripping to confirm pipe heavy or pipe light condition.

12.8.6 Sealing Elements

Damage to the preventer sealing elements can be reduced by regulating the closing line pressure to the minimum required to maintain a seal and by lubricating the pipe as it passes through the preventer elements. After stripping for a short time (10 or 20 tool joints), the regulator setting can be adjusted for the optimum closing pressure. One method to attain optimum pressure would be to reduce the pressure 50 psi while continuing to strip. If no leakage is detected during additional stripping (5 minutes, 1 or 2 tool joints), reduce the pressure another 50 psi. Continue the process until a leak is detected. Thereafter, increase pressure as needed to keep leakage minimal but adequate to keep the sealing element lubricated.

The pipe should be lubricated with a mixture of bentonite and water or some other lubricating fluid as it runs through the preventer to reduce packing element wear. It is necessary to know the spacing from the rotary table to the top of the annular preventer so that the tool joint can be eased into the packing element. The operator should be prepared to transfer control to another BOP when the sealing element fails or when the operating pressure exceeds the maximum operating pressure.

Ensure that the BOPE operating pressure does not exceed the OEM recommendations for the tubulars in use.

13 Slurries and Plugs to Deal with Lost Circulation and Underground Blowouts

13.1 Introduction

Lost circulation, underground blowouts, shallow gas flows, or the simple need to maintain a hole full of fluid are situations that lend themselves to slurries of various compositions and weights that plug formations or create barriers to flow in the hole. This section deals with testing, mixing, and placement of barite slurries, diesel oil/bentonite slurries, and cement slurries. These slurries will likely have a detrimental effect on any drilling fluid they encounter. Special handling procedures and equipment can be required.

The drilling fluid manufacturer should be consulted as to slurry composition and special handling recommendations to avoid problems. Environmental rules and regulations should also be reviewed. Use of slurries and plugs for these purposes should be a part of the well planning process.

13.2 Underground Blowouts

An underground blowout is uncontrolled flow of formation fluids from a high-pressure zone into a lower pressure zone. Characteristics of underground blowouts include: shut-in drill pipe pressure greater than shut-in casing pressure, erratic drill pipe pressure response, fluctuating casing pressure, or loss of large volumes of drilling fluid.

Underground blowouts can occur when the formation just below the casing seat fractures due to excessive annulus pressure or while drilling or working over a high-pressure formation in the presence of a depleted formation. It can be possible to heal the fracture or plug the depleted zone by pumping lost circulation materials. A gunk squeeze (refer to 13.5.1 and 13.5.2) can be pumped down the annulus while killing the high-pressure zone through the drill pipe with heavy drilling fluid. A gunk plug may also be pumped down the drill stem ahead of the barite slurry or heavy drilling fluid.

Another remedial approach for underground blowouts is to pump a barite plug down the drill pipe while bullheading as heavy as practical drilling fluid down the annulus. High fluid density, high viscosity, and high pump rates can be used to spot a non-settling high density pill on bottom to stop the flow.

13.3 Lost Circulation

13.3.1 General

Loss of workover fluid or loss of drilling fluid returns can lower the hydrostatic head of drilling fluid in the wellbore, which can lead to a kick. When this occurs, fluid inflow such as gas, oil, or water can reach the surface or flow into the loss zone of less pressure. The loss can result from natural or induced causes. Causes can include fractured, vugular, cavernous, sub-normal pressure or pressure-depleted formations. Pressure surges related to running pipe or tools (plunger effect) or breaking circulation can cause formation fracturing. Annular friction during circulation, sloughing shale, or casing pressures imposed in controlling a kick can also lead to lost circulation.

13.3.2 Development into an Underground Blowout

Loss of returns while attempting to control a kick can develop into an underground blowout. An attempt should be made to keep the hole full. If the hole will not support drilling fluid, the hole should be filled with a lighter drilling fluid or water down the annulus. The amount of fluid used should be recorded. Underground blowouts can lead to broaching.

13.3.3 Controlling the Situation with Slurries

The risks of blowout (surface or underground) should be evaluated when drilling fluid loss occurs (i.e., permeable zones exposed which can produce into the wellbore upon loss of hydrostatic head).

If partial loss of returns is occurring while circulating out a kick, consider reducing the pump rate to minimize or stop losses. If unsuccessful a fine sealing material can be added to the drilling fluid in an attempt to slow the loss. Evaluate the appropriate particle size and concentration of the sealing material to reduce the possibility of plugging the bit, choke, or choke line. A coarse sealing material can be bullheaded into the annulus to avoid plugging the bit; however, if there is no float in the drill string, it's advisable to continue pumping down the drill string to prevent plugging (refer to 4.11.1). Ideally, the lost circulation zone should be sealed either before a kick occurs or after the loss zone has been isolated from the influx zone with a barite plug or other procedure. If an underground blowout has already started, a barite plug (refer to 13.4 and its subparagraphs) can sometimes be used to isolate the loss zone from the kick.

13.4 Barite Pills / Plugs

13.4.1 General

In case of lost circulation or underground blowout, it can be necessary to attempt control using a barite plug. A barite plug is simply a slurry of barite in water, weighing about 18 to 22 pounds per gallon, that will bridge-off the hole due to high water loss and rapid settling when pumping is stopped. The use of a barite plug has several potential advantages over the use of cement; barite has a higher density, it is more likely to set up without any inherent channels, and it does not contaminate the drilling fluid system.

Note: If cement is not static it cannot set properly

13.4.2 Types of Barite Pill / Plug

Barite pills and plugs have been used within industry for many years as a well control technique. However, they are not an accepted conventional well control method, such as the driller's method or the wait and weight method and are not a first choice for killing a kick.

There are 2 variations of this barite slurry. One slurry is designed to keep the barite suspended. For clarity of this manual this 'non-settling' barite slurry will be termed a barite pill. The second design is a 'settling' slurry, called a barite plug. In the latter case, the intent is for the barite in the slurry to separate from the base fluid and form a "solid" plug in the wellbore.

The two slurry types have applications to wells that cannot be killed conventionally but each come with operational risks. Proper planning and good communication is important to successfully execute the pumping of barite pills and plugs.

Slurries can be prepared with any of the barite substitutes which are available on the market. The standard recipes in use allow for the use of higher density substitutes which will result in higher weight slurries than are possible with barite.

13.4.3 Barite Pill (Non-settling slurry)

Since barite settling is unpredictable the use of the barite pill is considered a more prudent approach. The goal of the barite pill is to kill the well by achieving a hydrostatic overbalance. The contributing factors of a hydrostatic kill are fluid density and fluid volume (pill height).

The pill design is a dual density design where the two mud weights in the hole that provide the EMW required for overbalance. This slurry is most beneficial for cases where:

- A slow feed cannot be killed because the casing shoe or downhole weak point cannot support the KWM

- Continued attempts to trip pipe result in swabbing and additional trip margin is required and exceeds the leak off

  Note: Mud rheology is a critical factor as additional mud density can result in higher swab pressures.

- When performing a "sandwich" kill; which involves pumping the barite pill down the drill pipe while simultaneously pumping a fluid down the annulus that can be supported by the shoe or open hole weak point. The two fluids are pumped with the intention of them arriving at the open hole weak point at the same time.

The list above is not an exhaustive list of the applications for a barite pill. The application of this technique to well control events is considered on a case-by-case basis.

When designing the pill the wellbore strength is a critical factor. It is important that the barite pill design does not generate excessive hydrostatic pressure on a zone resulting in losses. This will result in the inability to maintain the required hydrostatic pressure to keep the well dead.

13.4.4 Barite Pill Preparation and Pumping

Prior to mixing a barite pill the recommended slurry recipe is pilot tested on location to allow personnel to observe the effect once pumping is stopped. Modifications to the pill recipe are determined based on results of the pilot test and the mud rheology check.

In cases where the required pill density exceeds the capability of the mud system on location additional equipment is sourced. The equipment needed on location to prepare a barite pill that exceeds the mud system on location is a dual tank blender with agitators and the capability to circulate the two tanks. Adequate clean tankage for the mix water will be required if it is not already available.

A barite pill may be pumped by a cementing unit into the work string through a cementing head, configured kill tree or the stand pipe and Kelly. It is important that provisions are made to have a contingency pump tied in and ready in case the cementing unit fails while pumping the barite pill. Minimizing non-pumping time while the pill is in the pipe reduces the risk of plugging the string or bit. Blockage of the workstring by barite settling will complicate the well control problem.

Barite pills are pumped with the workstring close to the bottom of the hole. If there is any significant volume of original mud under the slurry, contamination can occur which can lead to unintended barite settling. Barite settling will result in a reduction in the hydrostatic pressure generated by the pill. Displacement of a barite pill is like a balanced cement plug. The slurry is left higher inside the workstring than the pill height in the annulus. This allows the string to slug as it is pulled or stripped from the well.

13.4.5 Barite Plug (Settling)

A barite plug is used in extreme situations where it is imperative that the bottom section of the borehole be sealed. Barite settling can stop unwanted flow by bridging effect without achieving a hydrostatic kill. This technique is used after exhausting conventional options to achieve a hydrostatic kill.

Laboratory tests have shown that the strength of a barite plug is variable and that low gas volumes can flow through a settled barite plug. There are many cases where pumping a barite plug has stopped well flows. A barite plug can fail unexpectedly and is never used in a well for permanent or even long-term isolation. A permanent means of isolation is set above the barite plug to provide a long-term barrier.

The main design of barite plug slurries is for the barite to settle out rapidly once pumping is stopped. This can be seen by performing a pilot test on location. Typically, a barite plug recipe consists of base fluid, barite and a thinner. When water is the base fluid caustic is used to adjust the pH. Proper design of the plug will create a settled-out barite plug that extends 100 to 200 feet above the pressure source. When determining the barite plug slurry size it is important to know that not all the barite in the slurry will settle. A general guideline is 70-75% of the barite in the slurry will settle if a plug is achieved.

Down hole conditions will impact the settling of a barite plug. With a gas flow the barite will rapidly separate from the mix water and fall. In the case of a water or liquid flow much less settling will occur as the flow has viscosity and carrying capability. In high volume liquid flows, barite plugs can be completely carried away having no effect.

Slurry density is not as critical a factor for a settling barite plug as a non-settling barite pill as this is not designed to achieve a hydrostatic kill. At certain densities a slurry can become ‘self-suspending’ and the amount of barite in the slurry can inhibit the settling rate. For open hole applications a general guideline is a slurry weight in the 15.8 ppg to 18.6 ppg range for water-based systems and 15.2 ppg to 17.6 ppg for oil and synthetic based systems.

13.4.6 Barite Plug Preparation and Pumping

Barite plugs are not mixed in rig mud tanks. The equipment needed on location to prepare a barite plug slurry is a dual tank blender with agitators and the capability to circulate the two tanks. Adequate clean tankage for the mix water will be required if it is not already available. If existing tankage on location is used for mix water they are thoroughly cleaned as contamination with mud will inhibit the settling capability of the slurry. Barite plug slurries in water-based systems have been mixed and pumped “on the fly” but, mixing the slurry in a blender results in a more consistent slurry density. Barite slurries in oil or synthetic based systems are mixed in a blender allowing the barite time to become ‘oil wet’. Many oil field mud service companies have a recommended barite plug recipe.

A barite plug may be pumped by a cementing unit into the work string through a cementing head, configured kill tree or the standpipe and Kelly. Given the slurry design, it is critical that provisions be made to have a contingency pump tied in and available in case the cementing unit fails while pumping the barite plug slurry. Often a drill is conducted to train involved personnel to quickly swap from the primary to the contingency pump efficiently. This is to minimize non-pumping time and the risk of a blockage of the workstring. A plugged string will complicate the well control problem.

Barite plugs are pumped with the workstring close to the bottom of the hole. If there is any significant volume of existing mud under the existing slurry contamination can occur which can inhibit barite settling. A barite plug is generally over-displaced from the workstring to prevent plugging the string and losing the conduit to bottom.

13.4.7 Pilot Testing of Barite Slurry

Table 13.1 illustrates three example formulations of slurries that can be used to produce barite plugs. These formulations are given in units for mixing laboratory pilot tests, field pilot testing in the absence of laboratory precision equipment, and a field formulation (39 bbl total volume). Generally, the highest density barite slurry that settles into a solid plug is desired.

13.4.8 Preparation and Testing of Pilot Samples

The pilot testing procedure listed below can produce qualitative or quantitative indications of which mixtures can have a better chance of forming successful barite plugs. The greatest volume of non-pourable settled plug material is preferred.

1) Use a high-speed mixer for blending the slurry.

2) Add phosphate, Tetra Sodium Pyrophosphate (TSPP) or Sodium Acid Pyrophosphate (SAPP) or a suitable lignosulfonate thinner, and caustic soda to the fresh water prior to adding barite. TSPP and SAPP are used to accelerate barite settling so that a hard plug is formed. Addition of caustic soda to raise the pH to 9.5 – 11.0 range creates better barite settling tendencies.

3) Add barite rapidly (within 5 seconds) then stir sample on high speed for 15 seconds.

4) Pour 200 ml of the sample into a 250 ml container (preferably a graduated beaker). The sample should settle rapidly into a high-density cake. Pour off the liquid phase after a settling time of 15 minutes. The container should have at least 100 ml of settled material that will not pour, i.e., the settled material volume should be at least one-half of the initial total volume placed in the container.

Table 13.1— Example Barite Slurry Formulations

Laboratory Pilot Test Formula		Field Pilot Test Formula	Field Preparation Formula (39 bbl total volume)
18 lb/gal. slurry			
Water	480cc	2 cups*	225 bbl
Phosphate	**1.25g±	$^{1}/_{4}$ teaspoon	25 lbs (approx. 10 qts.)
Caustic Soda	**0.5g±	$^{1}/_{10}$ teaspoon	10 lbs (approx. 4 qts.)
Barite	1150g	$2^{1}/_{4}$	210 sacks (100 lb. ea.)
		*8 fluid oz. coffee cups	(Note: A mud cup is about 1 qt.)
20 lb./gal. slurry			
Water	425cc	$1^{3}/_{4}$ cups*	22 bbl
Phosphate	**1.25g±	$^{1}/_{4}$ teaspoon	25 lbs. (approx. 10 qts.)
Caustic Soda	**0.5g±	$^{1}/_{10}$ teaspoon	10 lbs. (approx. 4 qts.)
Barite	1380g	3 cups*	250 sacks (100 lb. ea.)
		*8 fluid oz. coffee cups	
22 lb/gal. slurry			
Water	370cc	$1^{1}/_{2}$ cups*	19 bbl
Phosphate	**1.25g±	$^{1}/_{4}$ teaspoon	25 lbs (approx. 10 qts.)

Caustic Soda	**0.5g±	$^{1}/_{10}$ teaspoon	10 lbs. (approx. 4 qts.)
Barite	1635g	$3^{1}/_{2}$ cups*	295 sacks (100 lb. ea.)
		*8 fluid oz. coffee cups	

**For some barites and under high well temperature conditions, other thinners, notably lignosulfonates (up to 8 lb/bbl or more), may be used

Table 13.2—Slurry Volumes

Hole Diameter, in.	Feet of Hole Filled per Barrel of Slurry	Volume of Barite Slurry Required for 450 Feet of Open Hole, bbls
$6^{1}/_{4}$	26.3	20
$7^{7}/_{8}$	16.6	30
$8^{3}/_{4}$	13.4	35
$9^{1}/_{2}$	11.4	40
11	8.5	53
$12^{1}/_{4}$	6.85	65
$14^{3}/_{4}$	4.73	95
$17^{1}/_{2}$	3.36	135

Table 13.3—Barite Required (API Barite Specific Gravity = 4.20)

Slurry Density, lb/gal	Pressure Gradient, psi/ft	Water Vol., gal/sacks	Slurry Yield, bbls/sacks			
			100 sx	200 sx	300 sx	400 sx
18.0	.935	5.00	18.6	37.1	55.6	74.3
20.0	1.039	3.70	15.6	31.1	46.6	62.5
22.0	1.142	2.71	13.2	26.4	39.6	52.8

Table 13.4—Diesel Oil-Bentonite Drilling Fluid Reactive Slurries

Materials required for 10 barrels of slurry

Type	"Gunk" Diesel Oil-Bentonite	DOBC	DOB2C	DOBB2C
Diesel Oil, bbls	7.3	7	7	6.75
Bentonite, sacks*	23	14	10	4
Cement, sacks**		14	20	8
Barite sacks*				31
Density, lb/gal***	10.5	11.4	11.8	14.7

*100 lbs. net per sack.
**94 pounds net per sack (finest grind available).
***Density and final volume will vary depending on quality of materials used.

13.4.9 Barite Plug Procedure

A cement batch mixer should be used at surface for mixing barite plugs, then pumped through the drill pipe, and spotted as near to the influx zone as possible. The barite needs to settle rapidly to be effective, gas or saltwater percolating through the plug can prohibit the plug from settling thereby reducing its effectiveness. The drill pipe can become plugged or stuck if the operation is not performed rapidly and efficiently. Drilling fluid contamination of the barite plug should be avoided.

Table 13.2 presents volume information for placing barite slurry in various hole sizes. Slurry density-volume relationships are shown in Table 13.3. A cement batch mixer should be used to mix and displace the slurry. Barite should be mixed into fresh water containing the required amounts of phosphate or other thinner and caustic soda, as determined by pilot testing. Lines from the cementing unit can be connected directly to the drill pipe through a plug valve (i.e., low-torque valve).

Note: If a cement batch mixer is not available, a barite slurry can be mixed in the slugging pit if continuous and violent agitation action can be attained.

A barite plug is spotted by fully displacing the entire barite plug out of the drill string and into the annulus and allowing the barite to settle and form a solid plug.

13.4.10 Checklist for Barite Plug Operations

The following checklist of recommended operations should be considered in planning barite plug operations:

1) Determine how many feet of unsettled barite plug in the open hole is desired (450 ft is usually considered a minimum).

2) Choose a slurry weight that will produce the desired results.

3) Calculate barrels of slurry required.

4) Calculate amounts of fresh water, phosphate, or lignosulfonate, caustic soda, and barite required to produce desired barite slurry.

5) Perform pilot testing with available barite, water, and chemicals on rig.

6) Displace the barite slurry out of the drill stem utilizing drilling fluid to minimize the chance of backflow and bit plugging.

7) Wait for barite to bridge and plug (4 to 12 hours), holding backpressure to prevent further fluid influx. Bleed the annulus pressure slowly to confirm the plug is holding.

8) Consider running a temperature or noise log to determine if the underground flow has been stopped.

9) Proceed with the next operation(s) to strengthen or isolate the upper loss zone.

13.4.11 After Pumping a Barite Slurry

Barite slurries are pumped in a variety of situations. A procedure cannot be generated that will adequately address each. It is necessary that the engineering and operations teams prepare the procedures that apply. One procedural issue to address is whether to pull pipe after displacing the barite slurry as this may impact the displacement procedure.

The goal of the barite pill is to achieve a hydrostatic kill. Factors for consideration are hole stability if kill is achieved and confidence the barite will remain in suspension. To stop the flow the design of the barite plug is to create a downhole bridge. This can result in the string becoming stuck in the bridge if pipe remains on bottom after displacement. However, stripping the pipe out of the well is not without risk. The experience of the wells team and their local knowledge of the rig equipment and personnel will generate a specific procedure.

13.5 Squeeze Slurries

13.5.1 General

Lost circulation can often be remedied most quickly utilizing a squeeze slurry. Diesel oil-bentonite cement slurries (DOBC) thicken by mixing of the slurry with drilling fluid and can tolerate 50 – 100% dilution by the drilling fluid. High-water-loss, high-solids cement slurries thicken by partial dehydration. Both mixtures gain the strength of the cement.

13.5.2 DOBC Test Procedure

The following test procedure should be used to predict the applicability of particular oils in diesel oil-bentonite cement (DOBC) slurries. To a sand content tube add a representative sample of the diesel oil to the 20% line; then add water to the “mud-to-here” line. Shake vigorously for 10 seconds and allow it to stand for 10 minutes. If the oil and water separate into two distinct layers, the oil is satisfactory to use. However, if the oil and water separate into three layers, i.e., oil on top, a white emulsion in the center, and water on the bottom, the oil will not form satisfactory DOBC squeeze slurries. If a stable emulsion is formed, the oil should not be used. A pilot test using varying mixtures of drilling fluid and DOBC should be run to ensure downhole thickening of the slurry. DOBC slurries have failed due to surfactants present in the diesel oil, which will prevent the bentonite and cement from being wet by the water and “gunking up” to form a satisfactory seal.

13.5.3 DOBC Slurry Procedure

The following procedure is recommended for applying DOBC slurries to well lost circulation zones:

1) Locate the top of the lost circulation zone by using a temperature survey or other means.

2) DOBC slurries can be pumped through a bit or open-ended, however, mixing can be improved by using a special drill pipe sub prepared by plugging one end of one-half of a joint of drill pipe and drilling 15 to 20 holes (half inch diameter), spaced randomly around the joint.

3) Run the drill pipe, with a backpressure or check valve, to a point just above the casing shoe or 20 to 30 feet above the lost circulation zone.

4) Test the surface equipment and piping to the maximum anticipated working pressure.

5) Wash out all equipment with the diesel oil to be used. Caution: All pumping and mixing equipment must be free of water prior to preparing the slurry.

6) Pump five barrels or more of diesel oil into the drill pipe using a pump truck. This prevents contact between the drilling fluid and slurry during displacement.

7) Mix the required amounts of cement and bentonite into the diesel oil using a jet mixer. The slurry weight should be approximately 11.5 pounds per gallon. Guidelines for mixtures preparations are shown in Table 13.4.

8) Displace the slurry down the drill pipe and follow with a diesel oil pad.

9) When the cushion of diesel oil which precedes the reactive slurry reaches the bit or mixing sub, close the BOP and begin pumping drilling fluid down the annulus, using a second pump, while the reactive slurry is being

displaced from the drill string. The speed of the pump on the annulus should be held at a low constant rate. The initial pumping rate on the drill pipe should be greater than that on the annulus. The drill pipe pumping rate should be varied based on response of the casing pressure, so that the thickness of the drilling fluid plus reactive slurry being blended at the bit or mixing sub is thinner at the beginning and finally is thick enough to produce the desired squeeze pressure. A pilot test of mixture ratios of the reactive slurry with the drilling fluid in the annulus will help the supervisor select changes in the ratio as the two fluids are being mixed downhole. Estimates of the range of ratios required to yield a thin or thick mixture are shown in Table 13.5.

10) If the annulus will not stand full prior to starting treatment, fill it with water. It should begin filling soon after the slurry starts clearing the drill stem.

11) A surface pressure should be obtained on the annulus during displacement. If pressure is not obtained, attempt a "hesitation squeeze" while displacing the last one-fourth of the slurry volume. A "hesitation squeeze" is used to attempt to build up some squeeze pressure. Approximately one barrel of slurry should be left in the drill pipe at the completion of the squeeze. Do not attempt to reverse circulate. Release the pressure on the annulus, pull the drill pipe slowly, replace the bit, and drill out in not less than 8 hours.

12) Repeat treatment if circulation is lost while drilling out.

13.5.4 High-Water-Loss, High-Solids Cement Slurry (HWL-HS)

This is a low strength mixture of water, cement, barite for correct density, 10 – 20 pounds per barrel of a mixture of fibrous, flake, granular sealing materials, and HWL-HS additive. Table 13.6 presents a guide of suggested material quantities for preparing a one-barrel mixture of HWL-HS cement slurry.

Table 13.5—Trial Mixing Ratios for Reactive Slurry Mixtures

	DOB: "Gunk" Drig. Fluid: DOB	Drig Fluid: DOBC	Drig Fluid: DOB2C	Drig. Fluid: DOBB2C
Thin Mixture	8:1 to 4:1	4:1 to 6:1	4:1 to 6:1	4:1 to 6:1
Thick Mixture	2:1 to 1:1	2:5:1 to 1:1	2:5:1 to 1:1	2:1 to 1:1

* These suggested ratios should be refined by pilot testing before use on a specific job.

Table 13.6—Materials Quantities for Mixing One Barrel of HWL-HS Cement Slurry

Density, lb/gal	HWL-HS Additive, lbs	Cement, sacks		Barite sacks (avg.)	Water, barrell
		(Min.)	(Max.)		
9.5	15	1.0	1.4	0	.84
10.0	20	1.0	1.4	0	.83
11.0	20	1.0	1.4	1.0	.78
12.0	20	1.0	1.4	1.4	.75
13.0	20	1.0	1.4	1.8	.72
14.0	20	1.0	1.4	2.5	.68
15.0	15	1.0	1.3	2.7	.65
16.0	15	1.0	1.2	3.2	.61
17.0	12	1.0	1.2	3.8	.57
18.0	10	1.0	1.0	4.4	.54

Add to the above mixture 5 – 10 lb/bbl of mixed fibrous, flake, and granular sealing material and a 20 lb/bbl addition of mixed sizes of granular materials. If the mixture must be pumped through a bit, careful selection of the sealing materials must be made to prevent plugging bit jets.

13.5.5 Cement Retarders

Common cement additives may be necessary for successful slurry mixing and placement. Cement retarders should be added as required for pumping time. Turbulence inducers may be added for mixing and pumpability. In the lower range of slurry densities, calcium carbonate may be used as weight material for a better filler.

13.5.6 Mixing Procedure

Use of a blender truck and the following mixing procedure are recommended:

1) Measure water volume into the truck.

2) Add HWL-HS additive while running the blender.

3) Add barite and lost circulation materials.

4) Add cement (bulk may be quickest).

13.5.7 HWL-HS Cement Slurry Squeeze Operations

Take care to prevent pumping a slurry containing coarse lost circulation material through a bit or mud-motor with small diameter nozzles. It is more desirable and safer to pump the HWL-HS cement pill through a squeeze tool. In performing the squeeze, it is desirable to perform a “hesitation squeeze” once the bit or squeeze tool is clear of slurry. The “hesitation squeeze” is used to attempt to build up some squeeze pressure. The slurry should be spotted just as in any normal squeeze operation; however, pumping time should be considered critical and adequate precautions observed. Waiting-on-cement time between the squeeze and circulated drillout should be at least 8 hours and preferably, 12 hours or longer to allow sufficient setting time for the cement.

13.5.8 Recommended Procedures for High-Water-Loss, High-Solids Cement Squeeze

The following steps should be used in affecting HWL-HS cement squeeze operations:

1) Pull up far enough into casing so that volume of casing below the bit equals approximately one-third the total volume of the squeeze slurry.

2) Pump HWL-HS cement slurry down the drill stem to just above the bit or squeeze tool. Some drilling fluid may be needed to reach this stage if slurry volume is less than drill stem capacity.

3) Shut-in the well to assure slurry goes down the casing. Compensate for lack of returns on the annular side by filling the annulus with a fluid lighter than the drilling fluid. Pull drill string far enough into the casing to prevent sticking.

4) Follow slurry with enough drilling fluid to clear the drill string but leave enough slurry in the casing to permit three squeeze stages. Gas expansion may require periodic bleed-off of excess pressure through a choke line. This condition will be indicated by a buildup of pressure on both the casing and the drill stem. Some of this pressure can be used to help expel slurry water and to speed setting. Additional benefits will be continuous, slow void filling and additional control of intruding fluids.

5) Wait 3–4 hours, depending on hole temperature and conditions, and pump enough to get pressure communication from surface drill pipe to casing gauges. If the hole takes fluid, stop after one-third of slurry is squeezed from the casing.

6) Wait 4–6 hours and repeat step 4 and stop when casing pressure goes up to 500 psi or when another one-third of slurry is squeezed out, whichever occurs first.

7) Either repeat step 5 or circulate until annulus is clean. Utilize choke if needed.

8) Trip for new bit or to change bottom-hole assembly if squeeze pressure is 500 psi above formation pressure or wait remainder of 24 hours and start washing down.

Annex A

(Informative)

Kick Pressure and Gradient Calculations

A.1 Pressure Calculations

Several special pressure and pressure gradient calculations can aid a well control supervisor in understanding well control operations. These calculations are based on the following assumptions:

1) The wellbore is vertical,
2) The kick fluid is initially on bottom,
3) The kick fluid is 0.6 specific gravity hydrocarbon gas,
4) The influx is one discrete bubble occupying 100% of its annular space in a gauge hole, and
5) The influx gas is completely insoluble in the drilling fluid.

The four calculations discussed in this section are:

1) Kick gradient,
2) Maximum expected surface pressure,
3) Initial shut-in pressure gradient at the casing shoe, and
4) Maximum expected pressure gradient at the casing shoe.

While an accurate knowledge of these four items would be of benefit to the well control supervisor, the general lack of precision in defining the well kick parameters, gas mixing and migration, and uncertainties in field measurements, significantly affect the ability to precisely calculate these values. For these reasons, the well control worksheets (refer to Annex B) do not include steps requiring these calculations.

A.2 Kick Gradient Calculations

The apparent density of the kick fluids is given by the following relation:

$$\rho_k = \rho_o - \frac{(P_{csg} - P_{dp})}{0.052H_k}$$

(Equation A.1)

The kick density can be calculated from the kick volume, shut-in pressure, and hole dimensions after determining if the top of the kick extends above the top of the drill collars. The first step is to compute the annular volume in the annulus surrounding the drill collars, which is given as follows:

$$V_{dca} = \frac{(D_h^2 - D_{dc}^2)l_{dc}}{1029}$$

(Equation A.2)

If the kick volume is less than the volume of the annulus surrounding the drill collars, the density of the kick fluids is given by:

$$\rho_k = \rho_o - \frac{(P_{csg} - P_{dp})(D_h^2 - D_{dc}^2)}{53.5V_b}$$ (Equation A.3)

If the volume of the kick fluids exceeds the volume of the drill collar annulus, the density of the kick fluids is given by the following relation:

$$\rho_k = \rho_o - \frac{(P_{csg} - P_{dp})}{0.052L_{dc} + \frac{53.5(V_b - V_{dca})}{(D_h^2 - D_{dc}^2)}}$$ (Equation A.4)

The density of a gas kick should be in the range of 11/2 to 2 lb/gal. An oil kick should have a density of about 6 lb/gal, and a saltwater kick should have a density of about 9 lb/gal. The calculations assume that the kick fluid is on bottom and not mixed with the drilling fluid. This is seldom true. If the kick fluid extends above the drill collars when the calculations assume the fluid to be alongside the collars, the calculated kick fluid density, (k will be too low.

A.3 Shut-in Bottom-hole Pressure

The shut-in bottom-hole pressure is given by the following relation:

$$P_b = 0.052\ \rho_o\ TVD = P_{dp}$$ (Equation A.5)

A.4 Hydrostatic Pressure of the Kick Fluids in the Casing/Drill Pipe Annulus

The hydrostatic pressure of the gas after circulating the kick into the casing/drill pipe annulus is given by:

$$\frac{(W)}{A_c} = \frac{1.27W}{D_{csg}^2 - D_p^2}$$ (Equation A.6)

The total weight of the gas (W) in the kick can be determined from Figure A.1 using the calculated shut-in, bottom-hole pressure and the kick volume. In Equation A.6, the constant 1.27, = $4/^1/_4$.

A.5 Maximum Surface Pressure for Gas Kick Using Driller's Method

When using the Driller's Method, the maximum surface pressure from a gas kick occurs when the gas reaches the surface. The maximum expected surface pressure for the Driller's Method can be determined from Figures A.2 and A.3 using the following relation:

$$P_{surf} = P_g = (P_{dp} \times f)$$

(Equation A.7)

where

P_g is determined from Figure A.2, using (ρ_o and $\frac{(W)}{A_c}$

And, f is determined from Figure A.3, using $P_{add} = P_{dp}$.

The maximum expected surface pressure is determined from Figure A.2 using the original drilling fluid density and the hydrostatic pressure of the gas in the drill pipe/casing annulus as determined from Equation A.6. The factor (*f*) is determined from Figure A.3 and the gas column pressure (*Pg*) is determined from Figure A.2.

A.6 Maximum Surface Pressure for Gas Kick Using Wait and Weight Method

When using the Wait and Weight Method, the maximum surface pressure normally occurs either during the initial shut-in condition or when the gas has been circulated to the surface. The maximum surface pressure that occurs as gas reaches the surface when using the Wait and Weight Method can be determined from Figures A.2 and A.3 using the following relation:

$$P_{surf} = P_g + \left(P_{dp} \times \frac{ID^2}{D_n^2 - D_p^2} \times f \right)$$

(Equation A.8)

where

P_g is determined from Figure A.2, using (ρ_o and $\frac{(W)}{A_c}$

And, *f* is determined from Figure A.3, using

$$P_{add} = \frac{P_{dp} \times ID^2}{D_n^2 - D_p^1}$$

In this case, the pressure from Figure A.2 is determined using the required drilling fluid density rather than the original drilling fluid density and with the hydrostatic pressure of the gas in the annulus as determined using Equation A.6. The factor (*f*) is determined from Figure A.2 using a ratio of the inside area of the drill string to the annular area times the initial shut-in drill pipe pressure for the P_{add} term and P_g as obtained from Figure A.2. Migration and mixing of the kick fluids in the drilling fluid reduce the actual maximum surface pressure below the calculated value. The accuracy of the calculation decreases as the kick volume and mixing of the kick fluids in the drilling fluid increase.

A.7 Initial Shut-in Pressure Gradient at the Casing Shoe

A knowledge of the maximum expected well control pressures at the casing shoe and the formation fracture pressure at the casing shoe can aid the well control supervisor in judging the likelihood of an underground blowout or a partial loss of returns while killing the well. The two highest pressures occur during the initial shut-in conditions and after the gas has been circulated to the casing shoe. The maximum gradient for the initial shut-in conditions is based on the assumption that the casing/drill string annulus is full of drilling fluid. For this assumption, the maximum initial shut-in pressure gradient at the casing shoe is given by:

$$g_o = \rho_o + \frac{P_{esg}}{0.052 TVD_{esg}}$$

(Equation A.9)

A.8 Hydrostatic Pressure of the Gas Influx in the Open Hole/Drilling String Annulus

The maximum pressure that occurs after circulating the gas kick up to the casing shoe can be determined from the hydrostatic pressure of the gas in the open hole/drill string annulus immediately below the casing shoe and the relationships defined in Figures A.2 and A.3. The hydrostatic pressure of the gas kick in the open hole/drill string annulus is given by the following relation:

$$\frac{(W)}{A_h} = \frac{1.27W}{D_n^2 - D_p^2}$$ (Equation A.10)

A.9 Maximum Pressure at the Casing Shoe After Circulating Gas to the Casing Shoe Using the Driller's Method

The maximum pressure at the casing shoe while controlling a kick with the Driller's Method can be determined from Figures A.2 and A.3 and the following equation:

$$P_{shoe} = P_g + (P_{dp} + 0.052\ \rho_o\ TCD_{csg}) \times f$$

(Equation A.11)

where

P_g is determined from Figure A.2, using (ρ_o and $\frac{(W)}{A_c}$

And f is determined from Figure A.3 using

$P_{add} = (P_{dp} + 0.052\ \rho_o\ TCD_{csg})$ and P_g from Figure A.2.

P_g is determined from Figure A.2 using the initial drilling fluid density and the hydrostatic pressure of the gas in the open hole/drill string annulus below the casing shoe.

Factor (f) from Figure A.3 is determined using the sum of the initial shut-in drill pipe pressure and the hydrostatic head of the initial drilling fluid at the casing shoe for the P_{add} term.

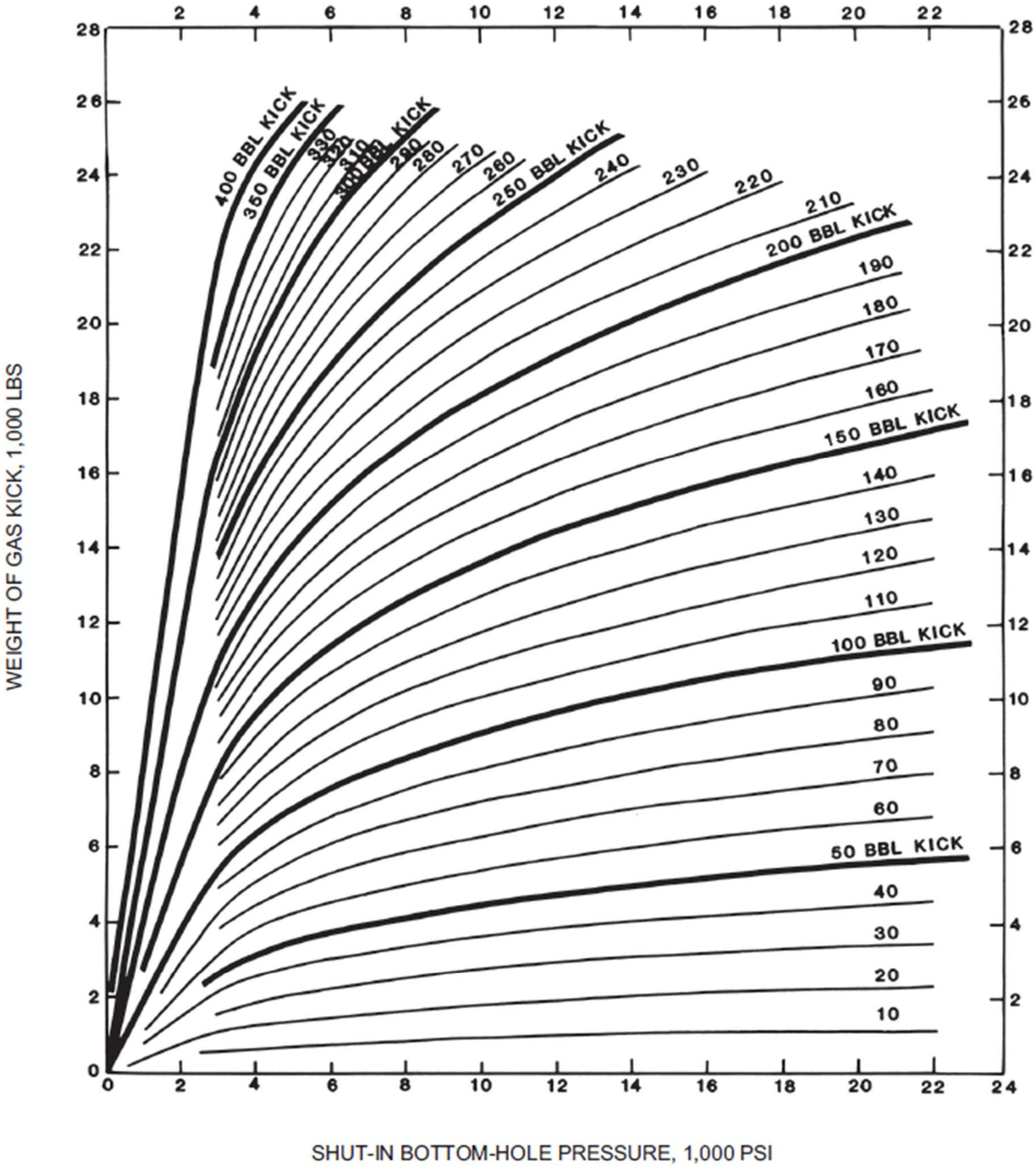
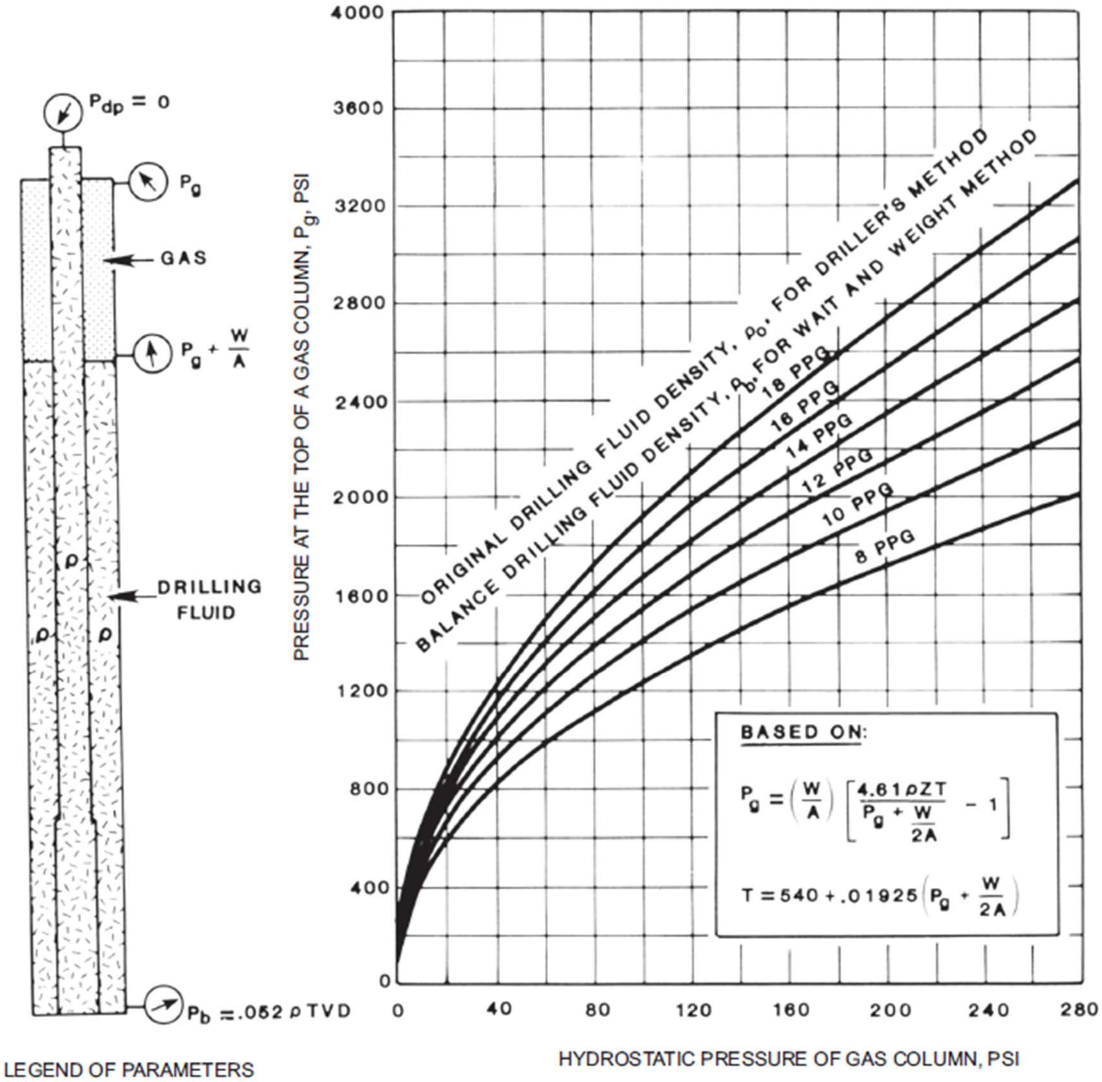


Figure A.1—Weight of a Gas Kick, 0.6 Gravity Gas



LEGEND OF PARAMETERS
USED IN DEVELOPING
FIGURE A.2

Figure A.2—Maximum Surface Pressure of a Zero Intensity Gas Kick ($P_{dp} = 0$)

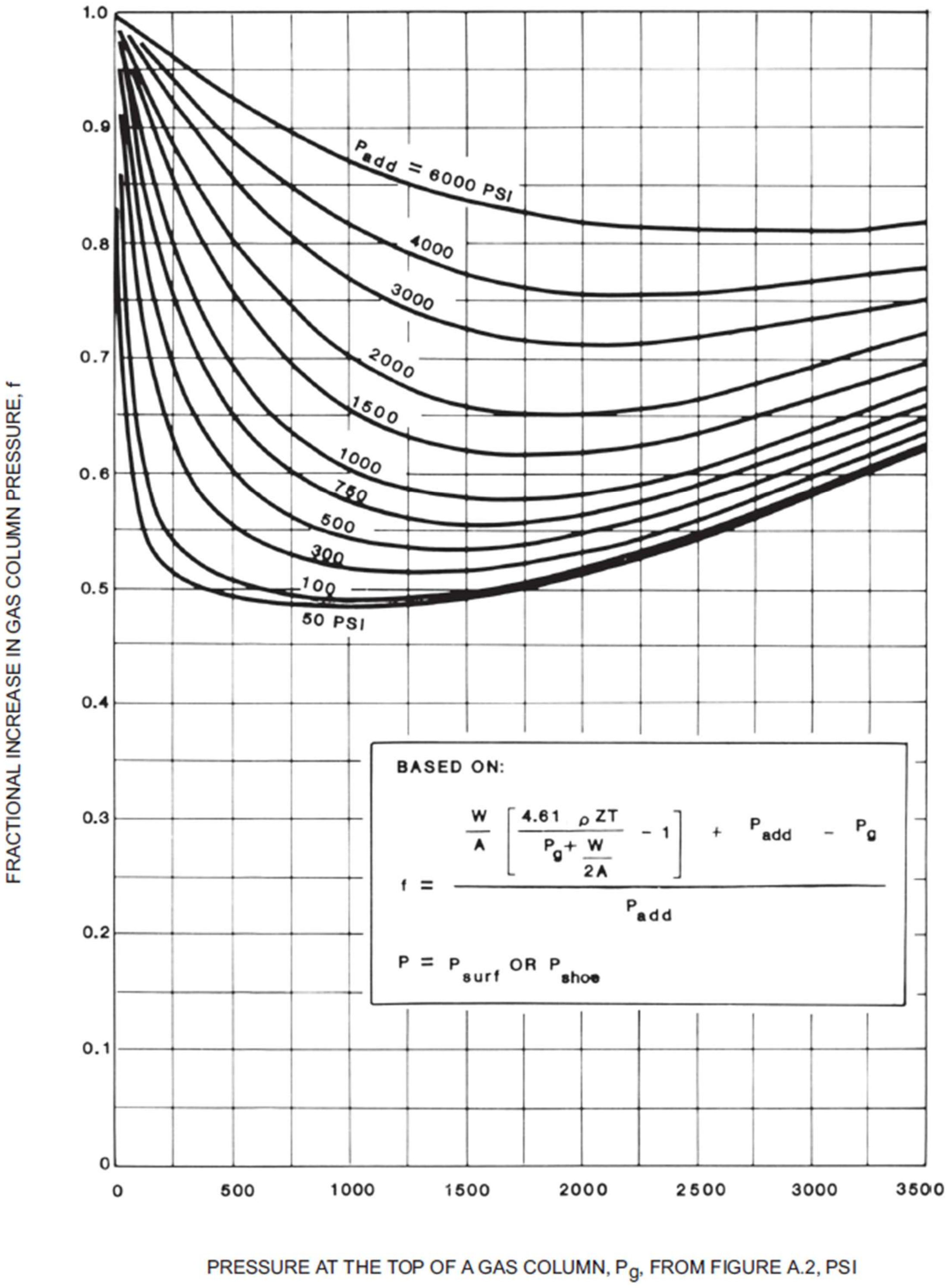


Figure A.3—Factor for Determining the Maximum Surface or Casing Shoe Pressure while Killing a Gas Kick with a Constant Bottom-Hole Pressure Method

A.10 Maximum Pressure at the Casing Shoe After Circulating Gas to the Casing Shoe Using the Weight and Weight Method

The maximum pressure at the casing shoe that occurs after circulating a gas kick to the casing shoe using the Wait and Weight Method can also be determined from Figures A.2 and A.3 using the following relation:

$$P_{shoe} = P_g + \left(P_{dp} \times \frac{ID^2}{D_n^2 - D_p^2} + 0.052 \rho_o TVD_{csg} \right)$$ (Equation A.12)

where

P_g is determined from Figure A.2, using (ρ_o and $\frac{(W)}{A_c}$

And f is determined from Figure A.3 using

$P_{add} = P_{dp} \times \frac{ID^2}{D_n^2 - D_p^2} + 0.052 \rho_o TVD_{csg}$ and P_g from Figure A.2

The pressure (P_g) is determined from Figure A.2 using the required drilling fluid density and the hydrostatic pressure of the gas in the hole/drill string annulus immediately below the casing shoe. The factor (f), determined from Figure A.3, is based on the P_{add} term that includes the sum of the ratio of the inside area of the drill string to the annular area times the initial shut-in drill pipe pressure plus the hydrostatic pressure of the column of the required drilling fluid density to the casing shoe.

A.11 Gradient at the Casing Shoe After Circulating Gas to the Casing Shoe

For either control method the equivalent pressure gradient at the casing shoe after circulating the top of the gas to the casing shoe is given by the following:

$$g_f = \frac{P_{shoe}}{0.052 TVD_{csg}}$$ (Equation A.13)

A.12 Example Calculations

The pressure and pressure gradient equations can be used to calculate the four desired parameters as shown by the following example:

Initial shut-in drill pipe pressure: P_{dp} = 500 psi.

Initial shut-in casing pressure: P_{esg} = 700 psi.

Initial shut-in kick volume: V_b = 50 bbls.

Total depth of well: TVD = 10,400 feet.

Original drilling fluid density: ρ_o = 9.5 lb/gal.

Diameter of the hole: D_h = 12 1/4 inches.

Depth of the casing shoe: TVD_{csg} = 4,000 feet.

Casing: 13 $^3/_8$ in., 72 lb/ft., N80.

Drill pipe: 5 in., 19.5 lb/ft., *XH*.

Drill collars: 600 ft of 8 in. *OD* x 3 in. *ID*.

For this well, the volume of the drill collar/hole annulus from Equation A.2 is given as follows:

$$V_{dca} = \frac{(D_h^2 - D_{dc}^2)L_{dc}}{1029} = \frac{(12.25^2 - 8^2) \times 600}{1029} = 50.2\text{bbls.}$$

Since the kick volume is less than the drill collar/hole annulus volume, the kick gradient is determined from Equation A.3 as follows:

$$\begin{aligned}\rho_k &= \rho_o - \frac{(P_{esg} - P_{dp})(D_h^2 - D_{dc}^2)}{53.5 V_b} \\ &= 9.5 - \frac{(700 - 500)(12.25^2 - 8^2)}{53.5 \times 50} \\ &= 9.5 - 6.43 \\ &= 3.1 \text{ lb/gal}\end{aligned}$$

The shut-in gradient of the kick fluids is 3.1 lb/gal. This suggests that the kick contains gas. Since the indicated density is greater than the density of gas, it is possible that the kick also contains some more dense fluid, or that the hole size near the bottom of the well is larger than 12 $^1/_4$ in., or that a portion of the gas is above the top of the collars. The maximum surface pressure if the well is killed with the Driller's Method is calculated from Equations A.6 and A.7 and Figures A.1, A.2, and A.3. Assuming that the kick is 100% gas, the weight of the gas in the kick is determined from Figure A.1 using the kick volume of 50 bbls, and the shut-in bottom-hole pressure determined from Equation A.5 as follows:

$$\begin{aligned}P_b &= 0.052 \text{ x } \rho_o\, TVD + P_{dp} \\ &= (0.052 \text{ x } 9.5 \text{ x } 10{,}400) + 500 = 5{,}638 \text{ psi.}\end{aligned}$$

From Figure A.1, using 50 bbls and 5,638 psi, the weight of the gas kick is determined to be 3,700 lbs.

The hydrostatic pressure of the gas in the casing/drill pipe annulus is given using Equation A.6 as follows:

$$\frac{(W)}{A_c} = \frac{1.27W}{D_{csg}^2 - D_p^2} = \frac{1.27 \times 3700}{12.347^2 - 5^2} = 37\text{psi}$$

The maximum surface pressure for a well killed with the Driller's Method is given by Equation A.7:

$P_{surf} = P_g$ (from Figure A.2) + $P_{dp} \times f$ (from Figure A.3).

P_g is determined from Figure A.2 using 9.5 lb/gal drilling fluid in $\frac{(W)}{A_c}$ of 37 psi. Figure A.2 shows P_g is 860 psi.

The term (f) is determined from Figure A.3 using P_g obtained from Figure A.2 and P_{dp} for the P_{add} term. For P_g equal to 860 psi and P_{add} equal to 500 psi, f is found to be 0.55. Therefore, P_{surf} for the Driller’s Method is equal to:

$P_{surf} = 860 + (500 \times 0.55) = 1{,}135$ psi.

If the well were to be killed with the Wait and Weight Method, the maximum surface pressure would be determined from Equation (A.8):

$$P_{surf} = P_g \text{ (from Figure A.2)} + \left(\frac{ID^2}{D_n^2 - D_p^2}\right) P_{dp} \times f$$

(from Figure A.3).

In this case, P_g is determined from Figure A.2 using the required drilling fluid density. The required drilling fluid density (ρ_b, is calculated as follows (using a 0.9 lb/gal trip margin):

$$\rho_b = \rho_o + \frac{P_{dp}}{0.052 \times TVD} \qquad \text{(Equation A.14)}$$

$$= 9.5 + \frac{500}{0.052 \times 10400} = 10.4 \text{ lb/gal}$$

For 10.4 lb/gal required drilling fluid density and 37 psi hydrostatic pressure of the gas column, Figure A.2 shows the P_g term to be 900 psi. The P_{add} term for Figure A.3 is computed as follows:

$$P_{add} = \frac{(ID^2)}{D_{csg}^2 - D_p^2} P_{dp} = \frac{(4.276)^2}{(12.347)^2 - (5)^2} \times 500 = 72 \text{ psi}$$

Using P_g equal to 900 psi and P_{add} equal to 72 psi, f is found to be equal to 0.49. The maximum surface pressure for the Wait and Weight Method is:

$P_{surf} = 900 + (72 \times 0.49) = 935$ psi.

For this example, the maximum surface pressure using the Wait and Weight Method would be 200 psi less than the maximum surface pressure for the Driller’s Method. The initial shut-in pressure gradient at the casing shoe is determined from Equation (A.9) as follows:

$$g_o = \rho_o + \frac{P_{csg}}{0.052 \times TVD_{csg}}$$

$$= 9.5 + \frac{700}{0.052 \times 4000}$$

$$= 9.5 + 3.4 = 12.9 \text{ lb/gal}$$

This maximum pressure gradient at the casing shoe depends on the well control method. The maximum pressure when the gas reaches the casing shoe for the Driller's Method is determined from Equations A.10 and A.11, Figures A.2 and A.3, and the previous data. The hydrostatic pressure of the gas kick in the annulus below the casing shoe is calculated from Equation A.10 as follows:

$$\frac{(W)}{A_c} = \frac{1.27W}{D_h^2 - D_p^2} = \frac{1.27 \times 3700}{12.25^2 - 5^2} = 38 \text{ psi}$$

The pressure at the casing shoe is given by Equation A.11 as follows:

$$P_{shoe} = P_g \text{ (from Figure A.2)} + (P_{dp} + 0.052\ \rho_o\ TVD_{esg}) \times f \text{ (from Figure A.3).}$$

Using a hydrostatic pressure of the gas column of 38 psi and an initial drilling fluid density of 9.5 lb/gal, Figure A.2 shows P_g to be 870 psi. The P_{add} term for determining *f* in Figure A.3 is equal to:

$$P_{add} = (P_{dp} + 0.052\ \rho_o\ TVD_{esg}) \text{ (Equation A.16)}$$

$$= 500 + 0.052 \times 9.5 \times 4{,}000 = 2{,}476 \text{ psi}$$

Using a P_g of 870 psi and a P_{add} of 2,476 psi, Figure A.3 shows that the f term is equal to 0.75; therefore, the maximum pressure at the casing shoe when gas has been circulated to the casing shoe using the Driller's Method is equal to:

$$P_{shoe} = 870 + (2{,}476 \times 0.75) = 2{,}727 \text{ psi}$$

If the well is killed using the Wait and Weight Method, the maximum pressure after circulating gas up to the casing shoe is given by Equation (A.12), as follows:

$$P_{shoe} = P_g \text{ (from Figure A.2)} + \left(\frac{ID^2}{D_n^2 - D_p^2}\right) P_{dp} + 0.052\ \rho_o\ TVD_{csg} \times f \text{ (from Figure A.3)}$$

The term P_g is determined from Figure A.2 using the hydrostatic pressure of the gas column and the required drilling fluid density. Using 38 psi as the hydrostatic pressure of the gas column and 10.4 lb/gal required drilling fluid density, P_g is found to be 910 psi from Figure A.2. The P_{add} term for Figure A.3 is equal to:

$$P_{add} = \frac{ID^2}{D_n^2 - D_p^2} \times P_{dp} + (0.052\rho_o TVD_{csg})$$

(Equation A.17)

$$= \frac{4.276^2 \times 500}{12.25^2 - 5^2} + (0.52 \times 10.4 \times 4000)$$

$$= 2{,}234 \text{ psi}$$

Using P_g = 910 psi and P_{add} = 2,234 psi, Figure A.3 shows the *f* term to be 0.73. Therefore, the pressure after circulating gas to the casing shoe using the Wait and Weight Method is given by:

P_{shoe} = 910 + (2234 x 0.73) = 2,540 psi

The pressure gradient at the casing shoe for these conditions is calculated from Equation (A.13).

$$g_t = \frac{P_{shoe}}{0.052 TVD_{csg}}$$

For the Driller's Method the gradient is:

$$g_t = \frac{2727}{0.052 \times 4000} = 13.1 \text{ lb/gal}$$

For the Wait and Weight Method the gradient at the casing shoe is:

$$g_t = \frac{2540}{0.052 \times 4000} = 12.2 \text{ lb/gal}$$

In the Driller's Method, the maximum gradient at the casing shoe occurs after circulating gas to the casing shoe. For this example, the maximum gradient would be 13.1 lb/gal which is 0.2 lb/gal greater than the gradient at the initial shut-in conditions. With the Wait and Weight Method the maximum gradient may occur either under the initial conditions or after circulating the gas to the casing shoe, depending on the kick volume and required drilling fluid density increase. For this example, the gradient at the casing shoe would be 0.7 lb/gal lower than the initial shut-in conditions after circulating gas to the casing shoe.

A.13 Nomenclature of Terms Used in Annex A

A_c = area of drill /pipe casing annulus, in.^{2} .

A_h = area of drill pipe/hole annulus, in.^{2}.

D_h = diameter of hole containing gas, in.

D_p = drill pipe OD, in.

D_{dc} = drill collar OD, in.

D_{csg} = casing inside diameter, in.

f = factor defined by Figure A.3, psi/psi.

G = specific gravity of gas, dimensionless.

g_o = maximum initial shut-in pressure gradient at the casing shoe, lb/gal.

g_f = pressure gradient at casing shoe after circulating gas kick to the casing shoe, lb/gal.

H_k = height of the kick fluids, ft.

h = length (height) of gas column, ft.

ID = inside diameter of drill pipe, in.

L_{dc} = length of drill collars, ft.

P_b = shut-in bottom-hole pressure, psi.

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

P_{csg} = initial shut-in casing pressure, psi.

P_g = pressure term determined from Figure A.2, psi.

P_{add} = pressure term used to determine f on Figure A.3, psi.

P_{surf} = maximum expected surface pressure while circulating a kick utilizing the constant bottomhole pressure method, psi.

P_{shoe} = maximum pressure at the casing shoe after circulating gas up to the casing shoe, psi.

T = gas temperature, degrees Rankin, R.

TVD = true vertical depth of kick zone and drill string, ft.

TVD_{csg} = total vertical depth of casing shoe (casing presumed vertical), ft.

V_b = initial shut-in kick volume (assumed at TVD), bbls.

V_{dca} = volume of the hole/drill collar annulus, bbls.

W = weight of the gas kick, lbs.

Z = gas compressibility factor, dimensionless.

ρ_o = density of drilling fluid in the hole at the time of the kick, lb/gal.

ρ_k = apparent density of kick fluids, lb/gal.

ρ_b = required drilling fluid density, lb/gal

Notes:

Derivation Information Related to Figure A.1.

In Figure A.1, the factor, 0.01935, is empirical. This factor is based on an observation by Louis R. Records and was published as follows: LeBlanc, J. L. and Lewis, R. L., “A Mathematical Model of a Gas Kick,” Journal of Petroleum Technology, August 1968, p. 888, Society of Petroleum Engineers, Richardson, Texas. Records’ observation in the Gulf Coast states that formation temperature and formation pressure are correlated reasonably well regardless of whether pressures are normal or abnormal. The factor, 0.01935, is derived as follows:

Formation temperature in the Gulf Coast area is estimated to be 80 F + 0.9 (F/100 feet of depth, in degrees F. In degrees R, this temperature would be 460 + 80 + 0.9 (F/100 feet). In a normal pressured interval, the formation pressure is 0.465 psi per foot of depth or 46.5 psi per 100 foot. Substituting this in the temperature relationship yields 540 + 0.01935 (pressure). The plot shown in Figure A.1 is exact excepting the empirical correlation between reservoir temperature and pressure.

Annex B

(Informative)

Well Control Formulas

LOT:

Formation fracture pressure (psi) = Leak-off pressure (psi) + [0.052 x Drilling fluid density (lb/gal) x Casing TVD (ft)]

It is useful to calculate the formation fracture gradient as equivalent or fracture drilling fluid density.

$$\text{Fracture drilling fluid density (lb/gal)} = \frac{\text{Leak-off pressure}}{0.52 \times \text{Casing TVD (ft)}} + \text{Drilling fluid density in use during test (lb/gal)}$$

Fracture pressure is the maximum surface pressure that can be applied to a casing that is full of drilling fluid without fracturing the formation. Fracture pressure is calculated as follows:

Fracture pressure (psi) = 0.052 x Casing TVD (ft) x
[Fracture drilling fluid density (lb/gal) – Present drilling fluid density (lb/gal)].

FIT:

Test pressure (psi) = 0.052 x Casing TVD (ft) x
[Required test drilling fluid density (lb/gal) – drilling fluid density currently in use (lb/gal)].

FCP:

$$\text{Final Circulating Pressure (psi)} = \text{Kill-rate Pressure (psi)} \times \frac{\text{New Drilling Fluid Density (lb/gal)}}{\text{Old Drilling Fluid Density (lb/gal)}}$$

Required drilling fluid density is calculated using the initial static, shut-in drill pipe pressure.

$$\text{Required drilling fluid density (lb/gal)} = \frac{\text{Closed-in drill pipe pressure (psi)}}{\text{Depth } (TVD)\text{, ft} \times 0.052} + \text{Present drilling fluid density (lb/ gal) in the drill pipe (and trip margin where appropriate)}$$