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Petroleum and natural gas industries — Drilling and production equipment — Shallow gas diverter equipment

Industries du pétrole et du gaz naturel — Équipements de forage et de production — Équipement déflecteur pour gaz de surface

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Contents

Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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For an explanation on the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the WTO principles in the Technical Barriers to Trade (TBT) see the following URL: Foreword - Supplementary information

The committee responsible for this document is ISO/TC 67, *Petroleum and Natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

Introduction

Drilling into shallow-gas-bearing formations is a very delicate and challenging operation. If the drilling operations are seriously complicated by the reduced safety margin available between kick and loss, the situation in case of a gas influx becomes extremely hazardous, due to a combination of the following adverse factors.

— Shallow gas flows are extremely fast-developing events; there is only a short transition time between influx detection and well unloading, resulting in a reduced time for the driller to take the right decision, and leaving little room for error.

— Past blowout reports have disclosed the magnitude of severe dynamic loads applied to surface diverting equipment. One of the associated effects is erosion, which adds a high potential for fire and explosion due to flow impingement on rig facilities which gives the gas flow access to various sources of ignition.

— Many past shallow-gas kicks turned into uncontrolled blowouts due to the failure of former diverter systems installed several decades ago. Failure is seen as a result of the system's complexity, its lack of functional reliability and its inability to cope with the severe dynamic loads.

— Certain drilling supports are exposed to specific threats associated with shallow gas blowouts, e.g. risk of cratering, risk of ship-shaped vessel capsize.

— Unprepared or inadequately trained drilling crews experience a high level of stress when facing a violent shallow gas flow.

In the aftermath of shallow gas blowouts during the last four decades, comprehensive inquiries and reports have been carried out, in particular by the specialists involved in combating these events, and significant findings and conclusions have been published. In the meantime, the manufacturing industry has developed various equipment aimed at significantly improving the safety of shallow-gas drilling operations.

This International Standard has been prepared taking these aspects into consideration.

Petroleum and natural gas industries — Drilling and production equipment — Shallow gas diverter equipment

1 Scope

This International Standard specifies requirements for the selection of the diverter equipment for rigs used to drill shallow-gas-bearing formations. It covers both onshore and offshore drilling operations, and considers also the auxiliary equipment associated with floating rigs.

The specified requirements concern the following diverter equipment:

— annular sealing devices;

— vent outlets;

— diverter valves;

— diverter piping.

This International Standard highlights the concerns associated with the selection of a marine floating drilling support. It covers safety issues concerning key rig equipment, and important steps of action required prior to starting the drilling operations.

It provides only general guidelines regarding the response to be given to a shallow-gas flow.

2 Normative references

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 13533, *Petroleum and natural gas industries — Drilling and production equipment — Drill-through equipment*

API 16D (latest revision), *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

3 Terms and definitions

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

3.1
actuator
device used to open or close a valve by means of applied manual, hydraulic, pneumatic or electrical energy

3.2
annular packing element
doughnut-shaped rubber/elastomer element that creates a seal in an annular preventer or diverter

Note 1 to entry: The annular packing element is displaced toward the bore centre by the upward movement of an annular piston.

3.3
annular sealing device
torus-shaped steel housing containing an annular packing element which facilitates closure of the annulus by constricting to seal on the pipe or kelly in the wellbore

Note 1 to entry: Some annular sealing devices also facilitate shutoff of the open hole.

3.4
bag preventer
device that can seal around any object in the wellbore or upon itself

Note 1 to entry: Compression of a reinforced rubber/elastomer packing element by hydraulic pressure creates the seal.

3.5
ball valve
valve that employs a rotating ball to open or close the flow passage

3.6
blowout
uncontrolled flow of well fluids and/or formation fluids from the wellbore or into lower-pressured subsurface zones

Note 1 to entry: When the uncontrolled flow of fluids goes into lower-pressured subsurface zones, it is termed an underground blowout.

3.7
blowout preventer stack
BOP stack
device that allows the well to be sealed to confine the well fluids in the wellbore

3.8
bottom-supported marine structure
drilling structure supported by the soil on the seabed while in the operating mode

Note 1 to entry: Rigs of this type include fixed platforms, submersibles, swamp barges and jack-up drilling rigs.

3.9
cleanout
point in the flow-line piping where the internal area of the pipe can be accessed to remove accumulated debris and drill cuttings

3.10
closing unit
assemblage of pumps, valves, lines, accumulators and other items necessary to open and close the BOP equipment and diverter system

3.11
control function
control system circuit (hydraulic, pneumatic, electrical, mechanical, or a combination thereof) used to operate the position selection of a diverter unit, BOP, valve or regulator

EXAMPLE Diverter “close” function, starboard vent valve “open” function.

3.12
control function
each position of a diverter unit, BOP or valve and each regulator assignment that is operated by the control system

3.13
diverter
device attached to the wellhead or marine riser to close the vertical access and to direct any flow into a set of vent lines and away from the drilling unit

3.14
diverter control system
assemblage of pumps, accumulators, manifolds, control panels, valves, lines, etc., used to operate the diverter system

3.15
diverter housing
permanent installation under the rotary table which houses the insert-type diverter assembly

3.16
diverter packer
annular sealing device of the diverter

3.17
diverter piping
vent lines of the diverter

3.18
diverter system
assemblage, comprising 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

3.19
diverter unit
device that embodies the annular sealing device and its actuating means

3.20
drill floor substructure
foundation structure on which the derrick, rotary table, draw-works and other drilling equipment are supported

3.21
drilling spool
flanged joint placed between the BOP and casing-head that serves as a spacer or crossover

3.22
drill ship
self-propelled, floating, ship-shaped vessel equipped with drilling equipment

3.23
dump valve
device used to control bottom-riser annulus pressure by establishing direct communication with the sea

3.24
dynamically positioned drilling vessel
DP drilling vessel
drill-ship or semi-submersible drilling rig equipped with computer-controlled thrusters which enable it to maintain a constant position relative to a fixed point on the sea floor without the use of anchors and mooring lines while conducting floating drilling operations

3.25
elastomer
any of various elastic compounds or substances resembling rubber

3.26
fill-up line
line, usually connected into the bell nipple above the BOP, to allow addition of drilling fluid to the hole while simultaneously pulling out of the hole to compensate for the metal volume displacement of the drill string being pulled

3.27
flex/ball joint
device installed directly above the subsea BOP stack and at the top of the telescopic riser joint to permit relative angular movement of the riser, thus reducing stresses due to vessel motions and environmental forces

3.28
flow-line
shaker line
piping that exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits

3.29
formation fracture pessure
value of pressure required to initiate a fracture in a subsurface formation (geologic strata)

3.30
function test
closing and opening (cycling) equipment to verify operability

3.31
gate valve
valve that employs a sliding gate to open or close the flow passage

3.32
hydrostatic head
true vertical length of fluid column

3.33
hydrostatic pressure
pressure that exists at any point in the wellbore due to the weight of the vertical column of fluid above that point

3.34
inner barrel
part of the telescopic slip joint on a marine riser that is attached to the flex joint beneath the diverter

3.35
insert-type packer
diverter element that uses inserts designed to close and seal on specific ranges of pipe diameter

3.36
integral valve
valve embodied in the diverter unit that operates integrally with the annular sealing device

3.37
interlock
arrangement of control system functions designed to require the actuation of one function as a prerequisite to actuate another

3.38
kelly
joint of pipe with flat or fluted sides that is free to move vertically through a bushing in the rotary table

Note 1 to entry: The bushing is termed a “kelly bushing”, and it imparts torque to the kelly thereby rotating the drill string.

3.39
kick
influx of gas, oil or other well fluids which, if not controlled, can result in a blowout

3.40
kill mud
drilling fluid with sufficient mud weight used to overcome the borehole pressure in case of well influx

3.41
knife valve
valve using a portal plate or blade to facilitate open and close operations

Note 1 to entry: A knife valve differs from a gate valve in that the bonnet area is open, i.e. not sealed.

3.42
lost circulation
loss of drilling fluid to the wellbore

3.43
marine riser
extension of the well-bore from the subsea conductor pipe housing or wellhead to the floating drilling vessel which provides for fluid returns to the drilling vessel and guides tools into the well

3.44
moored vessel
offshore floating drilling vessel which relies on anchors, chain and mooring lines extended to the ocean floor to maintain a constant location relative to the ocean floor

3.45
mud line
floor of an ocean, lake, bay or swamp

3.46
outer barrel
part of the telescopic slip joint on a marine riser that is attached to tensioner lines

Note 1 to entry: Tension is transferred through the outer barrel into the riser.

3.47
pre-spud
period of time which precedes the start of drilling activities

3.48
poor-boy separator
pressure vessel designed to provide effective separation of gas from drilling fluid at atmospheric pressure while circulating out a wellbore kick through the choke manifold

3.49
primary well control
prevention of formation fluid flow by maintaining a hydrostatic pressure equal to or greater than the formation pressure

3.50
production platform
permanently installed bottom-supported/connected offshore structure, fitted with drilling and/or production equipment for drilling and/or development of offshore oil and gas reservoirs

3.51
riser hydraulic connector
hydraulic latch which connects the 762 mm (30 in) conductor pipe housing and the bottom of the marine riser

Note 1 to entry: O-ring seals prevent leaks between the latch and the housing.

3.52
rotary table
device through which the bit and drill string pass and which transmits rotational action to the kelly

3.53
subsea diverter
seabed diverter
set-up of equipment attached to the bottom of the marine riser and connected to the 762 mm (30 in) subsea wellhead housing, designed to close the well in case of shallow-gas influx and to direct it through two subsea lateral vent outlets

3.54
semi-submersible
floating offshore drilling vessel which is ballasted at the drilling location and conducts drilling operations in a stable, partly submerged position

3.55
target
bull plug or blind flange at the end of a tee to reduce erosion at a point where change in flow direction occurs

3.56
targeted
having a type of fluid piping system in which flow impinges upon a lead (or other material)-filled end (target) or a piping tee when the fluid flow changes direction

3.57
telescopic joint packer
torus-shaped, hydraulically, pneumatically or mechanically actuated, resilient element between the inner and outer barrels of the telescopic joint which serves to retain drilling fluid inside the marine riser

3.58
vent line
conduit that directs the flow of diverted wellbore fluids away from the drill floor and to the atmosphere

3.59
vent line valve
full-opening valve which allows passage of diverted wellbore fluids through the vent line

3.60
vent outlet
point at which fluids exit the wellbore below the annular sealing device via the vent line

3.61
wellhead
apparatus or structure, placed on the top of the casings, that supports the internal tubular, seals the well and permits access to the casing annulus

3.62
working pressure rating
WP rating
maximum internal pressure that the equipment is designed to contain or control

4 Diverter system equipment

4.1 General purpose

The diverter system is designed to permit the drilling crew to blow down shallow-gas accumulations downwind of the rig. Until a sufficient casing length has been set to allow a well to be shut-in during a kick, the diverter system is the only line of defence, and is only expected to contain the hazard temporarily, although as long as possible.

The diverter system is not intended to be a well-control device. It simply allows the flow to be diverted in a safe manner in order to allow enough time to attempt regaining primary control of the well and, should the latter fail, enough time for proper evacuation of the drilling crew or for proper move-off of the drilling unit from the location (floating rigs), until the flow stops due to gas accumulation blow-down, hole bridging, hole collapse, etc.

Traditional diverter system components comprise:

— the annular sealing device;

— vent outlet(s) and vent line(s);

— valves;

— the control system.

4.2 Findings of blowout reports

Blowout inquiries have concluded that the original designs underestimated the fact that shallow-gas blowouts produce huge amounts of gas, together with abrasive solids, flowing at very high speed, producing severe dynamic loads, and eroding and destroying many parts of the existing diverter systems.

The failure of these diverter systems led unfortunately to the loss of many lives.

It is therefore of paramount importance to select suitable equipment able to function in a reliable and safe manner, i.e. able to operate whenever required under the worst possible conditions. Diverter equipment shall also be able to cope with the prevailing dynamic loads and associated effects.

The most frequent findings from blowout reports are as follows.

— Insert-type diverters have too many components.

— The locking mechanism of insert-type diverters is not really designed to contend with severe dynamic loads.

— Insert-type diverter packers cannot close on open-hole and on some drilling assemblies.

— Piston-actuated bag preventers are stronger and less complex, but close too slowly.

— Diverter outlets often promote erosion.

— Diverter vent lines are usually thin-walled, too small in diameter, have a tortuous path, and are inadequately supported, fastened and secured.

— Some valve systems are inadequate and unreliable.

— Layouts for control systems are too complex.

— Power sources of some control systems are not reliable.

— The maintenance of diverter systems is not given the same importance compared to BOPs.

4.3 Applications of diverter systems

Diverters are primarily used to divert flow from the rig in three situations:

— shallow fluid and gas flows;

— drilling with a rotating head;

— drilling with a marine riser.

This International Standard will not discuss the specific aspects associated with rotating-head drilling.

4.4 Layout considerations — Land rigs and bottom-supported marine structures

4.4.1 General

Drilling operations into shallow-gas-bearing formations include drilling from a land rig, or from a marine structure supported by a mat-type base, by legs, or drilling from a barge that rests on the bottom, e.g. jack-up drilling rigs, production platforms rigs and swamp-barge rigs.

Land rigs and bottom-supported marine structures have at their disposal a wide range of equipment to build diverter arrangements.

4.4.2 Types of annular sealing devices in use

4.4.2.1 Insert-type diverter assembly

In the insert-type diverter assembly, the insert packing is latched in place into a diverter assembly, which in turn is locked inside the support housing. This housing provides two outlets, one for the mud returns to flow towards the shakers, one for the diverted fluids to flow out through the vent line(s). The insert is removed prior to pulling or running the bottom-hole assembly (see Figure 1).

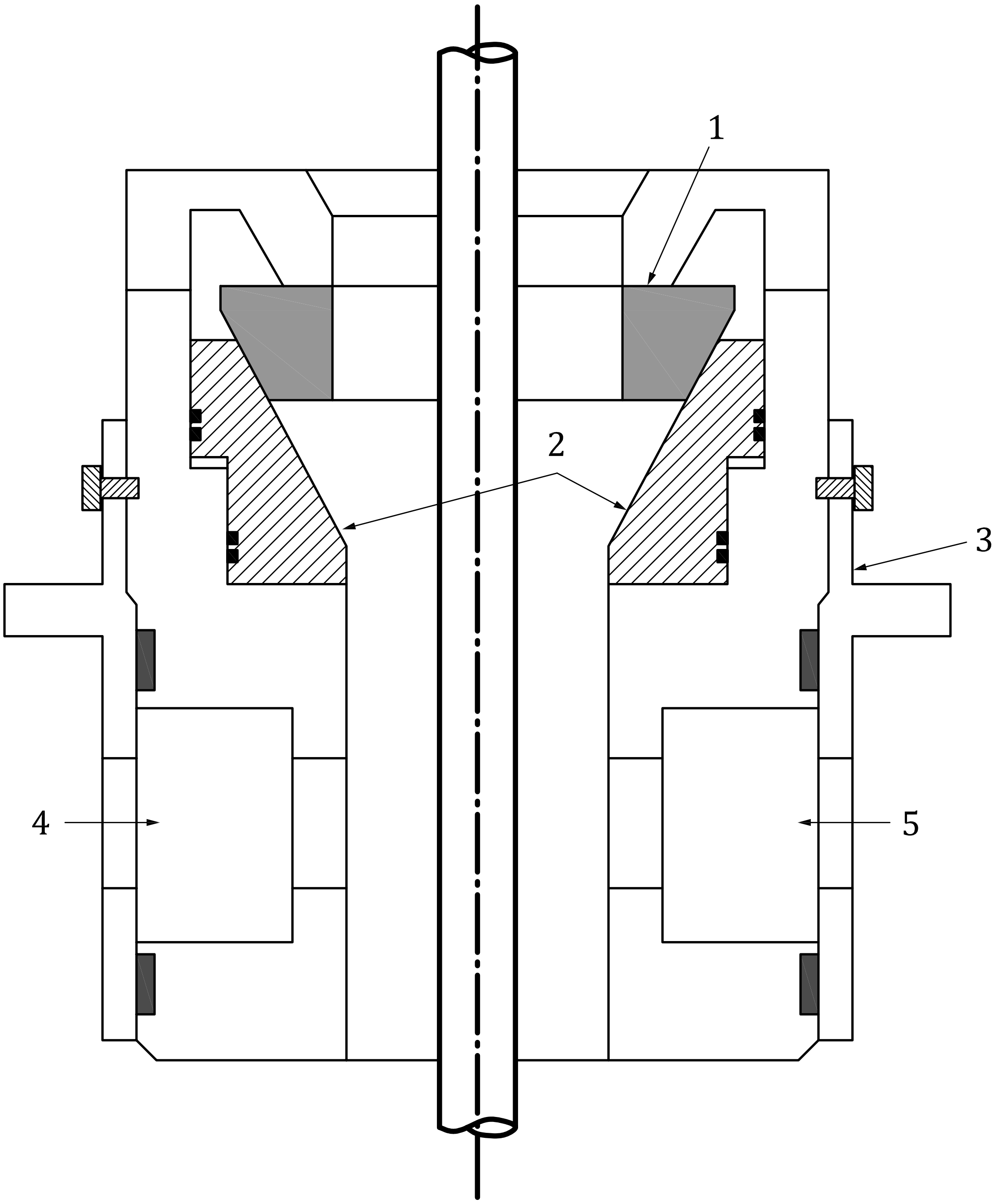
The rig substructure and the diverter assembly locking dogs shall be able to withstand the upward forces of the diverted fluid.

4.4.2.2 Annular packing element

This set-up requires a conventional bag-type preventer and a drilling spool (or diverter spool) which are directly located on top of the first casing (conductor pipe, drive pipe). This set-up is therefore below the rotary table and below the flow-line, unlike the insert-type diverter assembly (see Figure 2).

The connections shall be in accordance with the applicable provisions of ISO 13533. The annular packing element should be of sufficient internal diameter to pass the various bottom-hole assemblies and casing/liner strings required for subsequent drilling operations.

NOTE For the purposes of this provision, ANSI/API 16A is equivalent to ISO 13533.



Key

1 insert packing

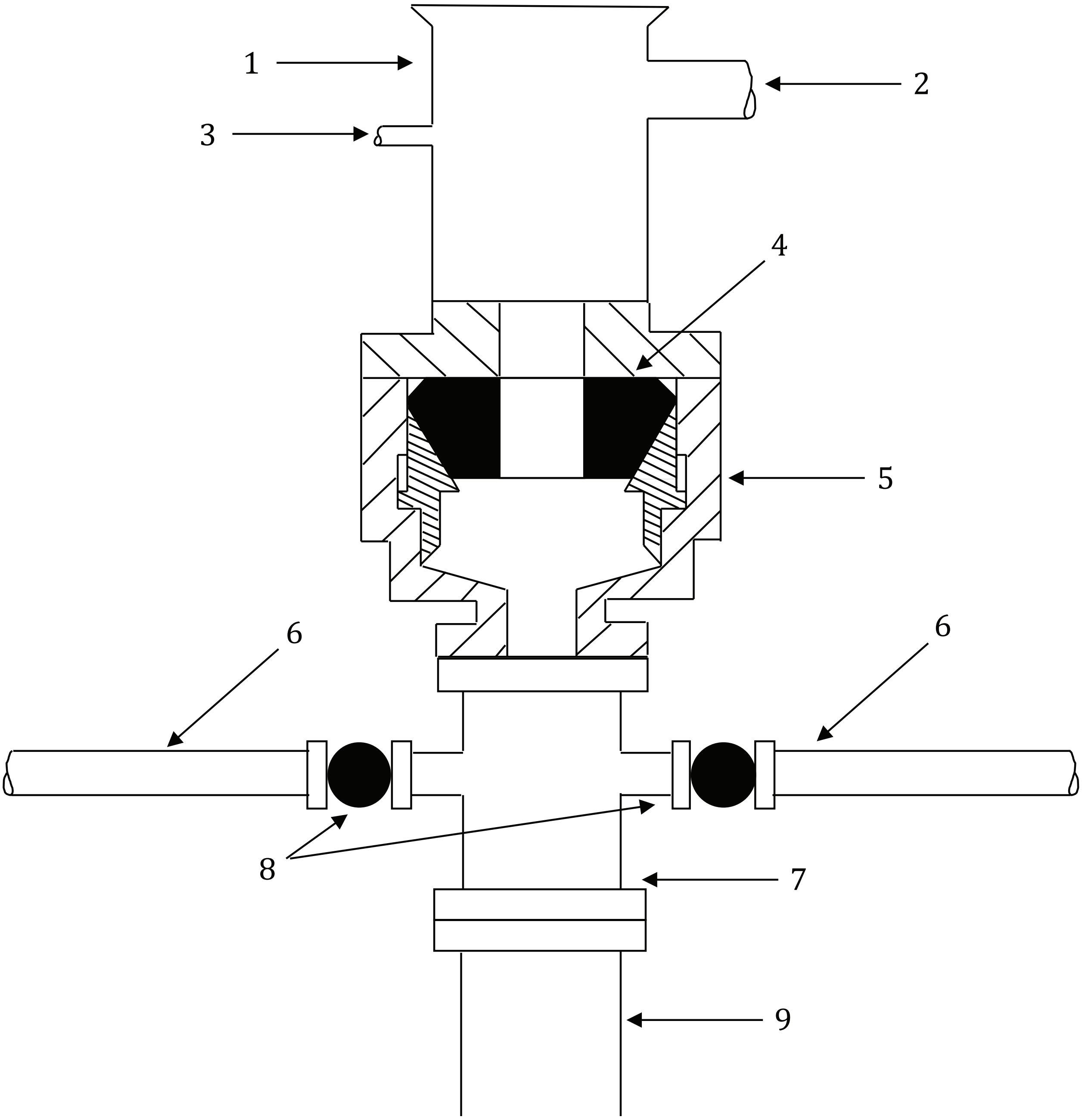
2 piston

3 support housing

4 flow line outlet

5 vent line outlet

Figure 1 — Example of insert-type diverter assembly



Key

1	bell nipple	6	vent line
2	flow line	7	diverter spool
3	fill-up line	8	hydraulically operated full opening valve
4	annular packing element	9	drive/conductor pipe
5	standard bag-type preventer		

Figure 2 — Example of diverter assembly with annular packing element

4.4.2.3 Comparison of systems

The two systems can be compared as follows.

a) Insert-type diverter assembly

- Advantages:
  - quick assembly;
  - flow-line, fill-up line and vent line permanently hooked up;
  - faster shut-in time;
  - light equipment, not cumbersome.
- Drawbacks:
  - the insert-type diverter system cannot withstand more than 3 447 kPa (500 psi) beneath the packer; this can be a problem when coping with severe gas flows;
  - insert-type packer never providing complete pack-off on open hole;
  - requires a significant number of valves, adding potential failure points;
  - requires complex sequencing operations and interlocks to activate the vent and flow-line valves;
  - requires complex control system and several power sources (pneumatic and hydraulic) to perform the closing sequence, adding potential failure points;
  - location likely to create potential erosion points in the flow-line if the latter is not properly designed;
  - overshot packer located below the diverter system, hence exposed to shallow gas flow;
  - ease of hook-up is largely outweighed by the potential for failure and leaks.

b) Classical annular packing assembly

- Advantages:
  - dynamic loads absorbed by the conductor pipe and the diverter system connection (clamp or flange);
  - reduced number of remotely controlled valves, due to the system position directly on top of the first casing and below the flow-line;
  - full-bore closing capacity often available;
  - no more overshot packer exposed to gas flow pressure below the diverter system.
  - Drawbacks:
    - cumbersome equipment;
    - longer nippling-up and nipple-down operations, hence including more initial expense;
    - vent lines require handling and adjustment,
    - excessive closing time of packing element.

4.4.2.4 Requirements for safe operation

4.4.2.4.1 General

Safe operation requires a standard hook-up including a bag-type preventer, together with a two-outlet drilling spool, made-up straight on top of the first casing string (drive pipe, conductor pipe).

The bag preventer shall be full-bore closing, with adequate internal diameter, and the response time kept equal to or even below the value given in API 16D. This can be achieved by means of e.g. bigger control lines, twin control lines, boosters.

Different sizes of bag-type preventers exist, e.g. from 508 mm to 749,3 mm (20 in to 291/2 in) with different pressure ratings. Although it is easy to find 508 mm (20 in) bag preventers rated 13 789 kPa (2 000 psi) working pressure (WP), the WP of most large-bore bag preventers ranges from 3 447 kPa (500 psi) to 6 895 kPa (1 000 psi). Nevertheless, in areas where shallow-gas risk is significant, a 13 789 kPa (2 000 psi) WP shall be considered, whatever the size of the bag-type preventer. Some manufacturers provide 711,2 mm (28 in) equipment rated up to 13 789 kPa (2 000 psi).

The standard hook-up option eliminates the need for a flow-line valve, as the flow-line is located at the level of the bell nipple, well above the diverter set-up.

The use of an overshot packer, required for length adjustment below the diverter system, is also eliminated, hence removing a potential leak point at pack-off level. Conversely, this adjustment joint and its packer can be used without risk above the bag preventer, as it will not experience any gas flow pressure.

4.4.2.4.2 The integral diverter system

Another safe alternative is to use an integral diverter assembly, which integrates the diverter spool and the annular packing into a single piece of equipment.

In this system the motion of the annular piston is used, in one stroke, to first open the vent lines and then stop the upward flow. The flow-line is located at the level of the bell-nipple, well above the integral diverter assembly, hence eliminating the need for a specific flow-line valve (see Figures 3 and 4).

An integral diverter system

— eliminates the need for a diverter spool and for the associated valves;

— reduces the number of components and functions;

— eliminates sequencing or interconnected control lines;

— eliminates the hazard associated with stagnant space;

— by design, prevents the vent lines from remaining closed while the well is already shut in;

— provides a faster shut-in time on 127 mm (5 in) drill pipes (20 s), compared to standard bag preventers;

— provides a large wellbore of size up to 711,2 mm (28 in);

— provides one or two large-bore vent outlets of size up to 406,4 mm (16 in);

— provides high structural strength to withstand the extreme dynamic loads of shallow-gas flows.

4.4.3 Vent outlets

The vent outlets for the diverter system are located below the annular packing element.

Vent outlets may be

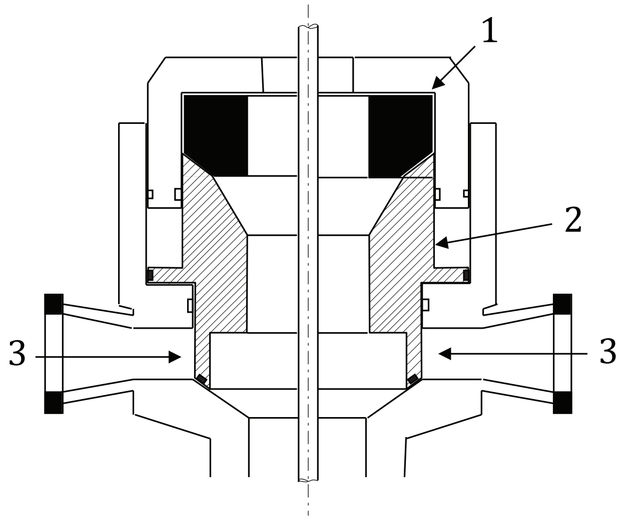
— incorporated in the diverter support housing, as for the insert-type diverter assembly;

— part of a drilling spool used below a conventional bag preventer;

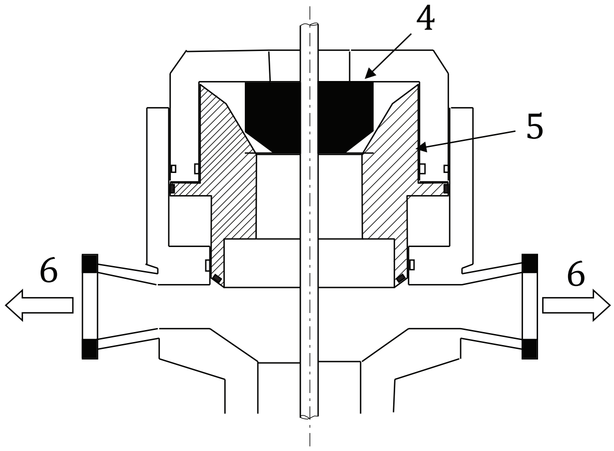
— part of an integral diverter assembly (see Figures 3 and 4).

The internal cross-sectional areas of the vent outlets shall be greater than or equal to that of the diverter vent lines.

Design considerations for the connection between the vent outlets and vent lines should include ease of installation, leak-free construction and freedom from solids accumulation.



a) Normal drilling operations



b) Diverting with pipe in hole

Key

1 packing unit (open position)

2 piston down

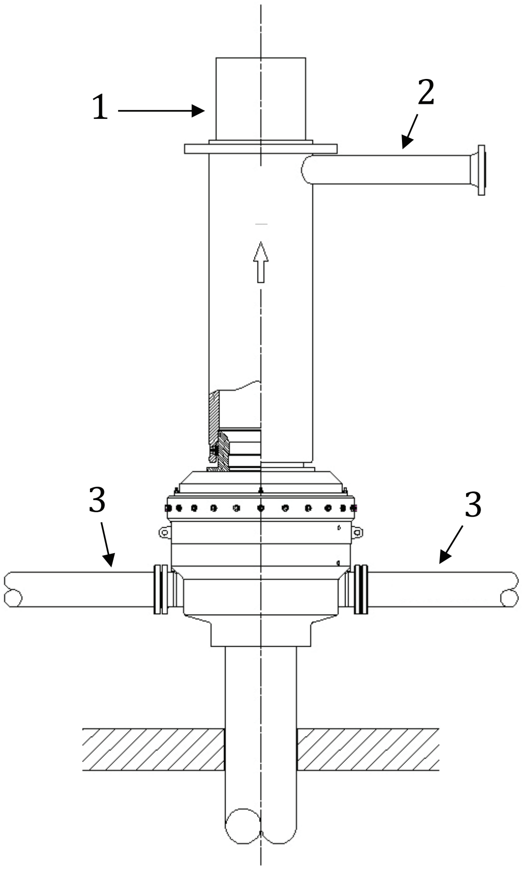
3 vent line shut in

4 packing unit (close position)

5 piston up

6 vent line open

Figure 3 — Principle of the integral diverter assembly (land and marine bottom-supported rigs)



Key

1 bell nipple

2 flow line

3 vent line

Figure 4 — Basic hook-up with an integral diverter assembly

4.4.4 Diverter valves

4.4.4.1 Review of equipment in use

Several types of valve are commonly associated with diverter systems: gate valves, ball valves, switchable three-way target valves, knife valves, valves integral to the diverter unit and sometimes burst disks.

Past experience has disclosed a high potential for failure of a large number of these valves:

— failure to open/close as required when subject to gas-flow pressure and dynamic loads;

— erosion of internal surfaces;

— failure of the sequencing and interlock systems;

— clogging and blocking with trapped sediments, ice, etc.

4.4.4.2 Selection criteria

Valves to be used in the diverter system shall:

— be reliable under severe shallow-gas flow conditions, i.e. be likely to work whenever required without any likelihood of failure;

— be full-opening;

— be of equal size as the diverter vent line;

— be remotely controlled;

— be capable of opening with maximum anticipated pressure across the valve;

— be installed in such a way as to limit the space for solids to accumulate;

— be easily maintained.

4.4.4.3 Requirements for safe operation

Safe operation requires the use of hydraulically operated full-opening ball valves, driven by an independent power source.

Valves shall be installed as close as possible to the annular sealing device, in order to minimize the space where debris could accumulate and plug the vent lines.

For insert-type diverter systems requiring actuation of valves on both shaker and vent lines, an interlock system shall prevent the diverter from closing before the valves are in the correct position (i.e. shaker valve closed, vent line valve open). This is of paramount importance with these systems, where the response time of the insert packer is much lower than that of the shaker and vent line valves [usually less than 10 s to close on a 127 mm (5 in) drill pipe].

Actuators fitted to a diverter valve shall be sized to open the valve with the rated working pressure (WP) of the diverter system applied across the valve.

4.4.5 Diverter piping

4.4.5.1 Pipe sizing and number

Erosion and pressure drop are major considerations in the design of diverter system piping.

Undersized and tortuous vent piping is subject to the hazardous effects of erosion due to cavitation, impingement of fluid and solid particles, etc., as revealed from blowouts during past decades.

It also

— is subject to elevated back-pressures and consequently to leaking/failure hazards in the diverter equipment;

— contributes significantly to an increase in the overall pressure of the well, adding the risk of formation fracturing and possible seabed cratering.

Many rigs have undersized vent lines ranging from 152,4 mm (6 in) to 254 mm (10 in). This is often due to the fact that models used for back-pressure calculations have widely underestimated the actual flow conditions. In particular, critical flow effects and multiphase conditions have not been accounted for, and shallow-gas blowout flow rates have been widely underestimated.

The consequences due to an undersized piping network are likely to be catastrophic.

The sizing requirements are mentioned in 4.4.5.7.

4.4.5.2 Pipe material

Diverter vent lines shall be made of steel piping.

4.4.5.3 Pipe routing

At the rig design stage, routing of the vent lines shall be planned to be as straight as possible, with no bends and branches, in order to minimize erosion, flow resistance, fluid-solid settling points and associated back-pressures. If routing changes are unavoidable, these should be as gradual as practicable, with a bend radius at least 20 times the inside diameter of the pipe (long-radius curvature).

For old generation rigs still having 90° bends, they shall include tees equipped with a targeted blind flange or a targeted plug. To prevent their failure, the tees shall be purpose-manufactured to withstand the significant loads and erosion potential from impinging well fluids. No branch is best, but use of Y-type branches is preferable to use of tee-branch connections.

Tees and other short-radius bends (if any) shall not be located at critical places, e.g. near power rooms, workshops or electrical rooms (see bibliography on the West Vanguard blowout report [6]).

The vent line(s) shall be sloped along its length (down, never up) to avoid low spots that can accumulate drilling fluid and debris.

4.4.5.4 Pipe heading

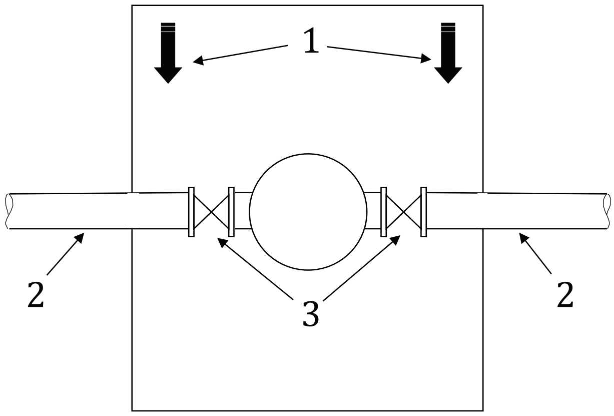
At the rig site location, the diverter vent lines shall extend a sufficient distance in the most appropriate direction from the rig to permit safe venting of diverted well fluids.

The following criteria shall be met:

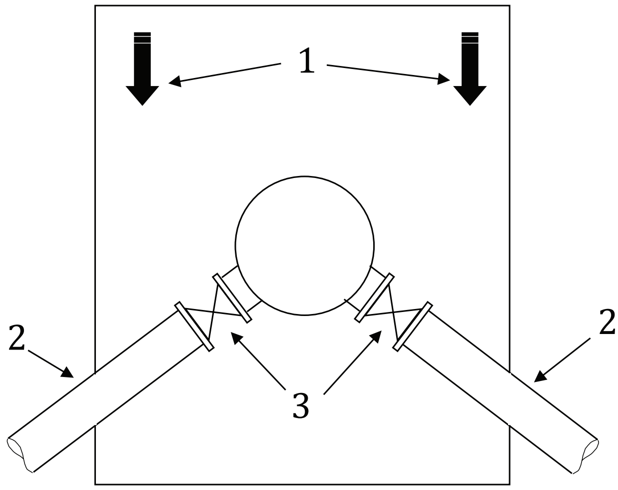
— the flow shall be prevented from being carried back to the rig (i.e. no vent line heading upwind);

— the flow shall be prevented from being carried towards populated areas, access/egress roads, etc.

A comprehensive review of local prevailing winds is necessary prior to selecting the appropriate piping heading. Unless major issues prevent doing so, the best option is to position the two lines opposite and crosswind, or with a V-shaped downwind layout (see Figure 5).



a) Crosswind heading



b) V shape downwind heading

Key

1 prevailing winds

2 vent line

3 hydraulically operated vent valves

Figure 5 — Heading of diverter lines

4.4.5.5 Pipe support and securing

Vent lines shall be firmly supported and fastened at least every 3 m, in order to withstand the dynamic effect of high-volume gas flow and the impact of drilling solids. On land, the use of large heavy bags can be considered to secure the vent lines until their termination.

Supports and fasteners located at points (if any) where piping changes direction shall be capable of restraining pipe deflection.

Special attention should be paid to the end sections of the vent lines, as diverter piping tends to whip and vibrate at this location.

4.4.5.6 Additional risks

Cleanout provisions are sometimes available for cleaning and flushing out accumulated debris upstream of valves and sharp changes in direction. These provisions nevertheless pose additional potential leak points, whenever subject to pressure of the gas flow at surface.

No flow-line or fill-up line shall be below the diverter packing element.

4.4.5.7 Requirements for safe operation

Safe operation requires the use of two straight steel vent lines, firmly supported and fastened at least every 3 m.

The required nominal ID of diverter outlets and vent lines shall be 355,6 mm (14 in) or larger. The vent lines' piping wall thickness shall not be less than 19,05 mm (0,75 in).

Hard-facing or extra thickness on the pipe outside diameter (OD) can be usefully considered in erosion-sensitive areas, such as bends and turbulent areas e.g. up/downstream of valves.

Changes in diameter shall be avoided. Welded flanges or hub connections are mandatory. Quick connections are not allowed in diverter vent lines.

A risk assessment including involved parties (operator and contractor as a minimum) for all exploratory and development wells engaged in shallow gas prone areas is required.

4.4.6 The control system

The diverter control system should be designed and sized in accordance with API 16D latest revision, section 5.5. It shall contain the minimum of functions. Preferably, a one-button or lever-activated function shall operate the entire diverter system.

A 38,1 mm (11/2 in) hydraulic operating line should be used for diverter systems with a 11/2 in NPT closing and opening chamber port size.

NOTE NPT stands for National Pipe Thread Taper [according to ANSI B1.20.1], US standard sizes for hydraulic connections.

As mentioned in 4.4.2.4, if a bag preventer is used, its response time shall be kept equal to or even better below the value given in API 16D. The use of e.g. two 38,1 mm (11/2 in) hydraulic operating lines on separate ports of the closing chamber is frequently recommended and used by manufacturers for large-bore bag preventers to decrease the response time to 20 s.

At least one pump of the hydraulic power unit which operates the diverter system and valves shall be powered by the emergency generator.

Many shallow-gas blowout reports have mentioned failures of the pneumatic control system used to operate diverter valves (e.g. failure to work as required when valves stems are blocked with solids). A pneumatic control system shall therefore be avoided on rigs, if possible.

4.4.7 Test-line facility

Each diverter system shall incorporate a test-line facility (including a check valve) to allow pressure-testing of the annular packing element closed on open hole, with no pipe in hole. This facility can also be used to periodically flush the system clean.

Another advantage of a test-line facility is to pump water through the diverter system during a gas-flow diverting operation, in order to wet the gas and accordingly reduce the fire risk.

4.4.8 Additional functions for the diverter system

The use of a diverter system (alone or combined with a BOP set-up) should be considered on multi-well platforms, due to potential hazards such as collision with adjacent wells or surface-gas accumulations due to poorly cemented casings.

4.5 Layout considerations — Floating rigs

4.5.1 General

Drilling operations into shallow-gas-bearing formations also include those carried out from moored or dynamically positioned drill-ships and semi-submersibles.

Once the initial casing (conductor pipe) has been set, drilling operations from these vessels may be conducted with or without a marine riser system.

Though many parts of the diverter system are identical to those used on land rigs and bottom-supported marine structures, others are specific to floating units and are reviewed hereafter.

When drilling shallow-gas-bearing formations with a riser, two types of sealing device may be used: the surface insert-type diverter assembly and the subsea diverter.

4.5.2 Annular sealing devices in use

4.5.2.1 Insert-type diverter assembly

By design, this system is basically similar to the system used on land rigs and bottom-supported marine structures. The diverter support housing is permanently fixed to the drill-floor substructure below the rotary table at the upper end of the marine riser system, and provides outlets for the shakers and for venting purposes. The diverter assembly is locked down inside the housing, and the insert packer is locked inside the latter.

The pros and cons of this system are identical to those identified in 4.4.2.3.

4.5.2.2 Subsea (or seabed) diverter

For floating supports, the possibilities to improve the surface vent lines network and routing being substantially reduced, the subsea diverter system is a safer alternative. The basic set-up includes, from top to bottom: a flex joint, an annular BOP (or a shear ram unit), a diverter spool and a riser hydraulic connector (see Figure 6).

This solution offers significant advantages, among which are:

— hazardous flow is kept remote from the rig and its crew;

— surface equipment is not subject to high thrust loads, erosive cutting, or fire and explosion hazards;

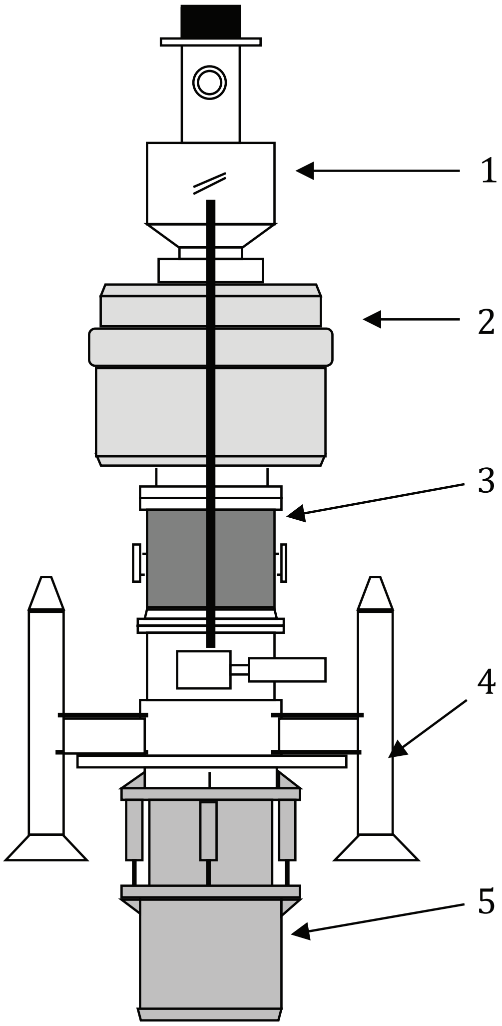
— other critical rig facilities are not jeopardized by a potential surface jet fire;

— time is made available for the crew to take the right decisions, and to eventually move safely off-location if needed.

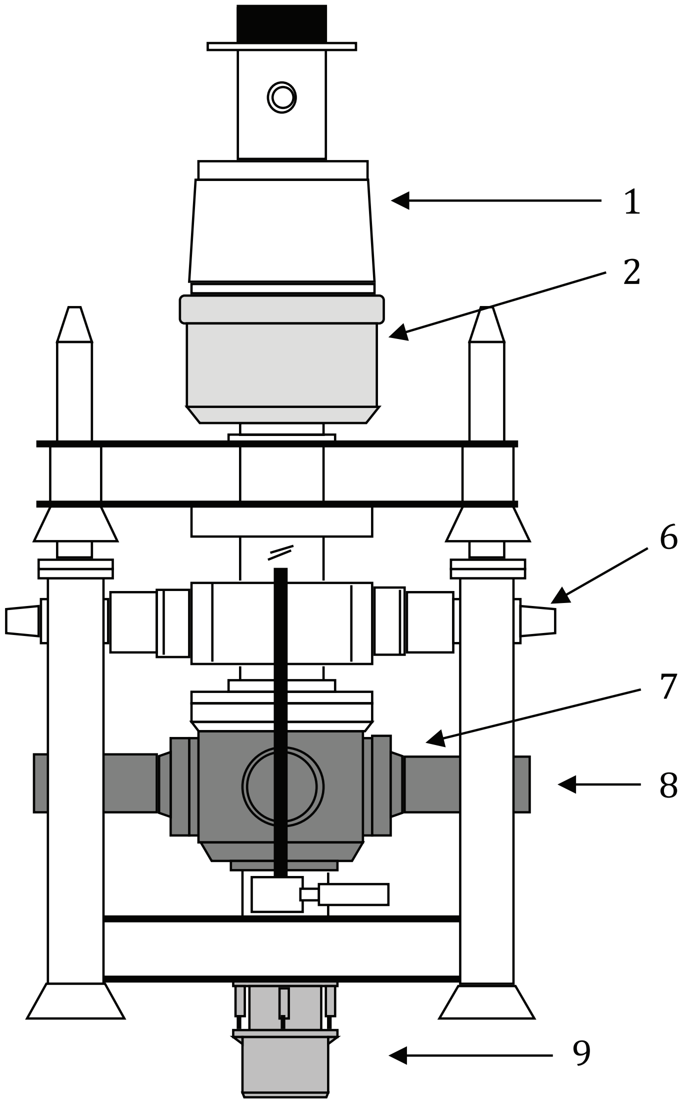
A shear ram unit and a high angle capacity connector are recommended to better secure the well and ease the move-off operations should prompt abandonment of the location be a top priority (in particular in shallow water depths).

Likewise, a riser booster line above the upper closing unit (bag or shear ram) is recommended to eliminate any gas which has entered the riser before complete well shut-off. At rig level, a surface diverter system is required to deal with this gas influx (see also 4.5.2.3 and 5.2).

Prior to using a subsea diverter, it is important to look carefully at the water depth and the type of support vessel which has been selected. Even after its transit through the water column, gas still represents a potential explosion and fire hazard, mainly as it concentrates in the moon-pool area. With gas being vented at seabed level and percolating up to surface, the subsea diverter is probably not the best choice with a drill-ship in shallow water depths.



a) Example 1



b) Example 2

Key

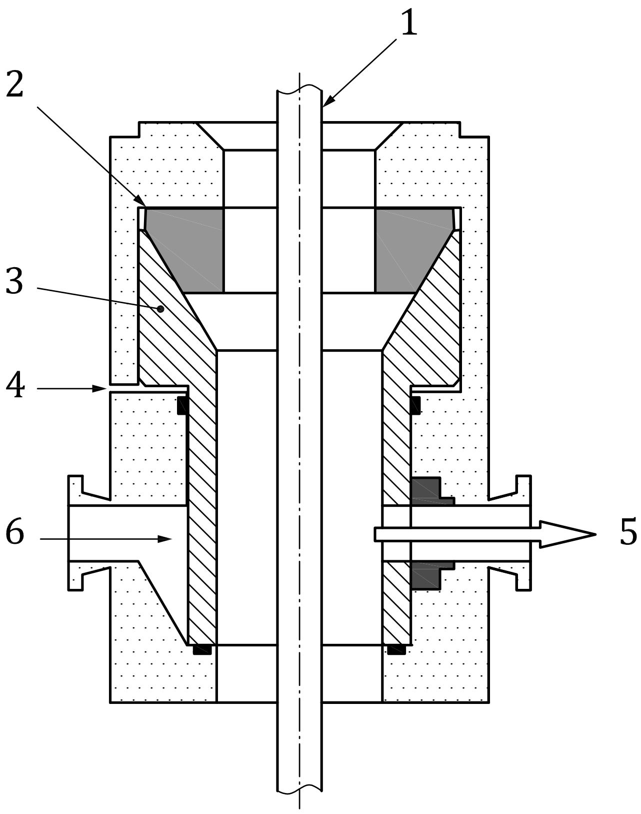
1 539,7 mm (21 1/4”) flex joint
2 539,7 mm (21 1/4”) annular BOP
3 539,7 mm (21 1/4”) diverter spool w/ integral valving and 304,8 mm (12”) outlets
4 guide structure
5 762 mm (30”) hydraulic connector
6 539,7 mm (21 1/4”) shear ram
7 539,7 mm (21 1/4”) diverter spool
8 outlet nozzle
9 762 mm (30”) hydraulic latch

Figure 6 — Examples of subsea (or seabed) diverter systems for floating rigs

4.5.2.3 Requirements for safe operation

For surface diverting, the requirement for safe operation is to use the integral diverter system (see Figure 7). The use of the insert type diverter shall be restricted to areas where the likelihood to drill through shallow gas bearing layers is extremely low.

The integral diverter system eliminates the need for valves and interconnected circuitry, eliminates the need for sequencing, ensures positive opening of vent lines prior to well shut-in, decreases significantly the probability of equipment failure and eliminates stagnant vent line space, hence preventing caking of solids or ice formation that could obstruct or shut off the flow.



Key

1 drill pipe

2 annular packing element

3 piston

4 close port

5 flow line open

6 vent line closed

NOTE The diverter is shown here in the drilling mode. When the diverter closes in case of gas influx, the piston moves upward, opening the flow path to the vent line while closing the flow path to the flow line.

Figure 7 — Example of integral diverter system for floating rigs

If surface diverting is definitely considered as too hazardous, the requirement for safe operation is to use the subsea diverter. Its use depends however on the water depth at the drilling location, the virulence of reported local shallow-gas events, the type of support vessel contemplated and the competence of the chartered drilling contractor.

4.5.3 Auxiliary diverter system equipment for riser drilling

4.5.3.1 Riser hydraulic connector

The 762 mm (30 in) hydraulic connector is the sealed interface connection between the 762 mm (30 in) housing topping the conductor pipe and the marine riser. Depending on water depth, a framework may be fixed to the hydraulic connector to provide guidance for the latching operation (see Figure 8).

Two issues should be considered when using the hydraulic connector.

— the release mechanism is generally too slow;

— quick and easy release of the latching dogs can be prevented due to an excessive angle and tension at the level of the hydraulic connector.

Specific measures should be considered to resolve these issues (e.g. additional hydraulic boosters and cylinders, friction-reduction coating).

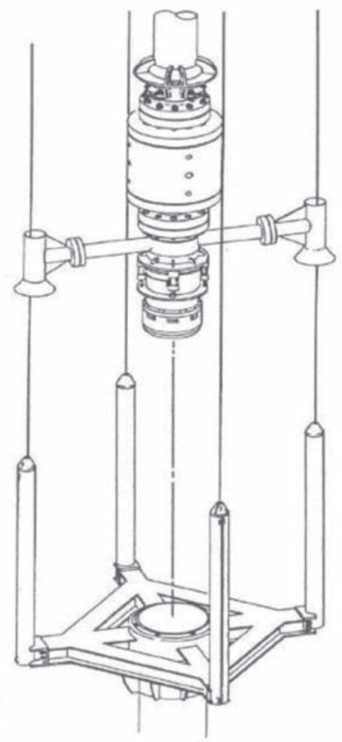


Figure 8 — Example of hydraulic connector system for floating rigs

4.5.3.2 Subsea dump valves

Some rigs use a set of two dump valves mounted above the riser hydraulic connector. Among the supporting arguments presented by dump valve users:

— possible water flooding into the marine riser to wet the gas, thus reducing the fire hazard and the surface pressure;

— possible diverting of the gas out through the dump valve, thus relieving the stress applied to surface equipment.

However, shallow-gas blowout events are very fast developing, and mud-dumping will inevitably speed up the riser unloading process. Moreover, computer simulations have shown that gas flow out through the dump valves to the seabed is unlikely to occur.

The use of subsea dump valves shall therefore be avoided.

4.5.3.3 Flex/ball joint

The flex/ball joint is an important component in the riser system, made up just above the riser hydraulic connector. It permits relative angular movement of the riser elements and hence reduces bending stresses caused by floating-support lateral offsets or by environmental forces such as marine currents. Its role is mainly to permit easy riser disconnection, within an acceptable range of angular deflection from the vertical.

Another ball joint is usually located at the top of the inner barrel of the telescopic joint.

4.5.3.4 Telescopic joint

Intended to compensate for heave of the floating support, the telescopic joint is another important element of the riser system. It consists of an inner barrel attached beneath the rig floor, and an outer barrel attached to the marine riser. Packing elements provide a sealing capacity between both barrels, and are intended to create an efficient seal in the case of shallow-gas flow.

The packing elements have many times proven to be a conspicuous leak point during shallow-gas events. Telescopic joints should incorporate double seals, to improve the sealing capability when gas has to be circulated out of the marine riser.

The remote control panel of the packing system shall be located in the drillmaster's cabin, and not in the moon-pool area which might be inaccessible in case of a gas leak at the telescopic joint packing level.

4.5.4 Diverter outlets and valves

The same comments for land rigs and bottom-supported marine structures given in 4.4.3 and 4.4.4 apply to vent outlets and diverter valves for floating rigs.

4.5.5 Diverter piping

4.5.5.1 Requirements

All comments made in 4.4.5 are equally applicable to floating drilling supports for:

— pipe sizing and number;

— pipe routing;

— pipe material;

— heading;

— support and securing;

— requirements for safe operation.

In addition:

— all diverter vent lines shall be routed to overboard;

— there shall be no connection between the diverter vent lines and the poor-boy/atmospheric mud-gas separator.

4.5.5.2 Pipe size and number

On floating rigs (as for land rigs and bottom-supported marine structures), since the size and number of vent lines have a great influence on surface and downhole hazards, two properly sized vent lines shall be used. The nominal ID of diverter outlets and vent lines shall be 355,6 mm (14 in) or larger.

4.5.5.3 Pipe heading

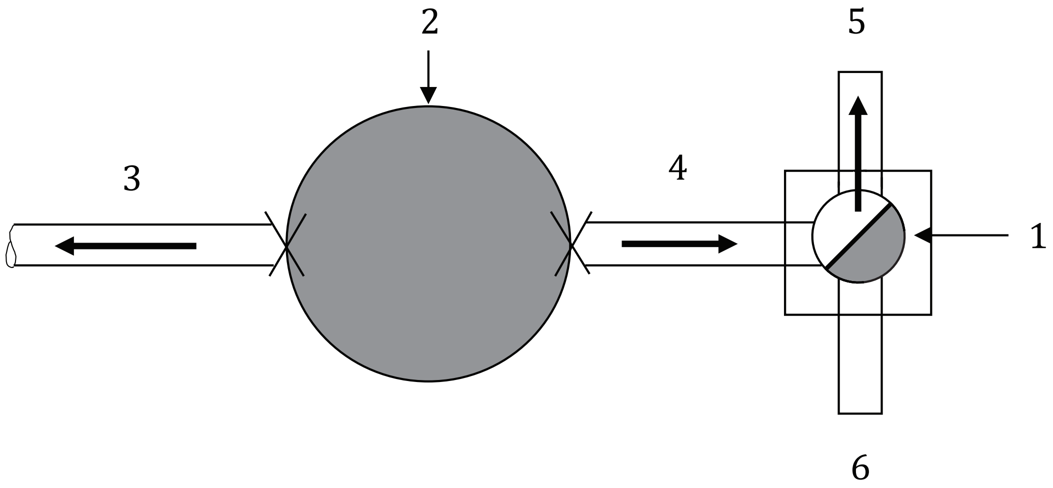
Whether or not a floating rig is moored, it shall adopt the same pipe heading as depicted in Figure 5.

4.5.5.4 Piping tees

On floating supports, tees are unfortunately frequently installed on the unique vent line outlet in order to divert the gas flow towards either side of the vessel. Problems have been reported in the field due to metal targets breaking loose from the tees and moving downstream.

Whenever compliance with above mentioned requirements for straight vent lines is not possible, a new type of erosion-resistant and reliable flow selector may be used (see Reference [7] on the subject). It includes a switchable target which allows the vent path to be permanently open during actuation, thus preventing any chance of inadvertent system shut-in in the case of power-supply failure. It allows the flow to be directed toward either port or starboard, depending on prevailing winds (see Figure 9).

It shall be located as close as possible to the diverter system vent outlet. It can be used on vent lines with an ID up to 406,4 mm (16 in).



Key

1 flow selector always open
2 diverter with integral valve functions
3 to shale shaker
4 to vent lines
5 to starboard vent line
6 to port vent line

Figure 9 — Principle of flow selector system

4.5.6 Control system

The diverter control system should be designed and sized according to API 16D latest revision, section 5.5. Pneumatic control systems shall be avoided on rigs working in shallow-gas-prone areas.

At least one pump of the hydraulic power unit which operates the diverter system and valves shall be powered by the emergency generator.

5 Floating rigs — Specific aspects

5.1 Use of the marine riser

Each operating company has its own drilling policy with respect to using (or not) the marine riser while drilling shallow-gas-prone formations. Some operators adopt a riserless approach. The following comments can be made.

a) Drilling with a riser.

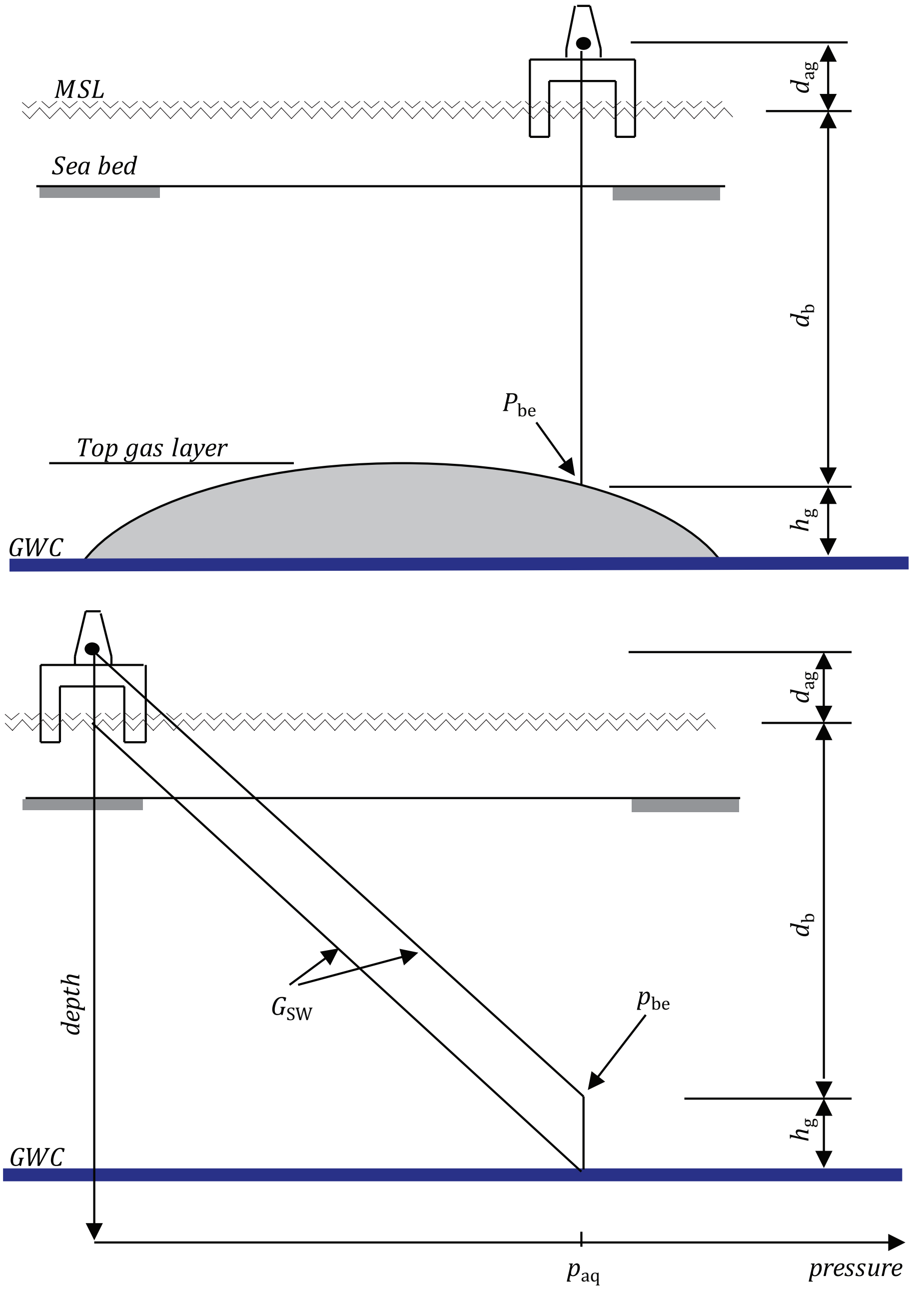
- The hydrostatic head provided by the mud column in the riser is the only means for ensuring a positive balance over the gas pressure. The mud column extending above sea level in the air gap section acts as an extra well-control capacity (see Figure 10).
- Mud returns allow proper mud characteristics monitoring to prevent both losses and kicks; they allow circulating out kicks and pumping kill mud to attempt regaining primary control over the well.
- The use of a riser entails reliable and tested systems to release the bottom of the riser and to move off the vessel from location in complete blackout conditions.
- The riser provides a direct conduit for uncontrolled wellbore flow to reach the drill floor. Well kill operations are more difficult due to the large diameter of risers.
- The deeper the water, the more likely the formation fracture pressure may present a significant problem and expose the well to potential mud losses when drilling with a riser.
- As water depth increases, the risk of riser collapse increases as gas displaces the mud inside the riser.

b) Drilling without a riser.

- Drilling riserless does not allow monitoring of mud characteristics and does not provide information about drilled formations.
- If seawater only is used while drilling riserless in an abnormally pressured shallow-gas zone (see 6.6.1), this zone will most likely flow (confirmed by several blowout reports).
- Drilling riserless allows faster vessel move-off, but only provided that facilities are available, tested and reliable to release the mooring lines, including in complete blackout conditions.
- A shallow-gas zone can be drilled riserless using a weighted drilling fluid with returns directly to the sea floor. This approach, which can provide enough hydrostatic head to overcome the gas pressure, involves higher drilling-fluid loss and costs, and requires special procedures.

c) Safe approach.

Whatever the pros and cons of riser use, a preliminary careful and thorough review of the reliability and capacity of the rig diverter system (see 4.5.2) and of the reliability and capacity of the emergency-release system of the floating-support mooring lines can provide decisive criteria to assist in selecting the best strategy.



Key

d_{ag}	air gap
d_b	bit depth, from mean sea level
GWC	gas water contact
G_{SW}	sea water gradient
h_g	height of gas column between bit entry depth and GWC
G_{MW}	mud gradient
MSL	mean sea level
p_{aq}	aquifer pressure at GWC
P_{be}	point of bit entry
p_{be}	pressure at point of bit entry

Figure 10 — The riser air gap as a well-control device

From Figure 10, using the symbols in the Key, it is seen that, for riser drilling, the pressure at point of bit entry is:

$p_{be} = p_{aq}$ − hydrostatic pressure of gas column ≈ p_{aq} (gas gradient being negligible at shallow depth)

$p_{be} = (d_b + h_g) \times G_{SW}$ (the usual pore pressure gradient is close to G_{SW}).

The hydrostatic head required to balance the gas-zone pressure at bit entry depth = $(d_{ag} + d_b) \times G_{MW}$.

Hence:

$$(d_b + h_g) \times G_{SW} = (d_{ag} + d_b) \times G_{MW}$$

$$(d_b \times G_{SW}) + (h_g \times G_{SW}) = (d_{ag} \times G_{MW}) + (d_b \times G_{MW})$$

$$h_g \times G_{SW} = (d_{ag} \times G_{MW}) + (d_b \times G_{MW}) - (d_b \times G_{SW})$$

$$h_g = (d_{ag} + d_b) \times (G_{MW} / G_{SW}) - d_b$$

If $G_{MW} = G_{SW}$, then $h_g = d_{ag}$

It can be concluded that:

— drilling with a riser full of sea water provides a means for controlling a shallow-gas zone that has a thickness equal to or less than the air gap. Likewise, the heavier the mud weight in the riser, the thicker the gas zone that can be safely drilled through.

When drilling without a riser with sea water, then $d_{ag} = 0$, $G_{MW} = G_{SW}$,

$$h_g = d_b \times (G_{MW} / G_{SW}) - d_b = d_b \times [(G_{MW} / G_{SW}) - 1] = d_b \times [1 - 1] = 0$$

It can also be concluded that drilling without a riser and with sea water will not prevent a gas-bearing zone from flowing.

5.2 Additional functions of the diverter system

On floating supports, the diverter system can also be employed after installation of the BOP as follows.

— Gas can inadvertently enter the riser when the BOP is shut-in on a kick. Gas can also enter the riser if the rams leak after the BOP is closed. Using the diverter system, the gas in the riser can be safely removed and diverted overboard.

— After a kick circulation is completed, some compressed trapped gas can remain between the closed BOP and the choke-line connection. This gas will tend to migrate into the riser when the BOP is re-opened. Using the diverter system, this gas can also be safely removed and diverted overboard.

5.3 Comparison of types of floating support

5.3.1 Moored drill ships

Moored drill-ships have a low freeboard, and are therefore extremely sensitive to fire and explosion hazards when gas penetrates the moon-pool area.

Likewise, the low-freeboard design of moored drill-ships exposes them to the risk of water jetting up the moon-pool area and flooding into the hull through open hatches, or through compartments damaged by fire and explosion. This flooding can cause a critical heel of the vessel.

In shallow waters, large side-loads are applied to the moored drill-ships by the strong radial currents induced by a plume welling up below the vessel. This load is likely to overstress the vessel anchoring system. Critical heeling into the plume can occur if the mooring lines are not quickly released, and eventually result in capsize of the vessel (this scenario has occurred several times in the past).

Additional loss of freeboard can be experienced by moored drill-ships due to the concurrent effects of slight loss of buoyancy (<8 % in the most severe cases) in the aerated sea water, rise of the water surface and of the froth layer near the boil zone (see Figure 11).

5.3.2 DP drill-ships

By design, DP drill-ships are significantly less exposed than moored drill-ships to shallow-gas blowout hazards, among other reasons due to their much higher freeboard.

5.3.3 Semi-submersibles

The air gap on a semi-submersible exposes any gas reaching the sea surface to air currents which dissipate the gas or blow it away from the rig, thus significantly reducing fire and explosion hazards.

Semi-submersibles have more freeboard than moored drill-vessels, since drill floor and marine decks are located far above the crest of most plume boils; this protects the compartments from flooding hazards (see Figure 12).

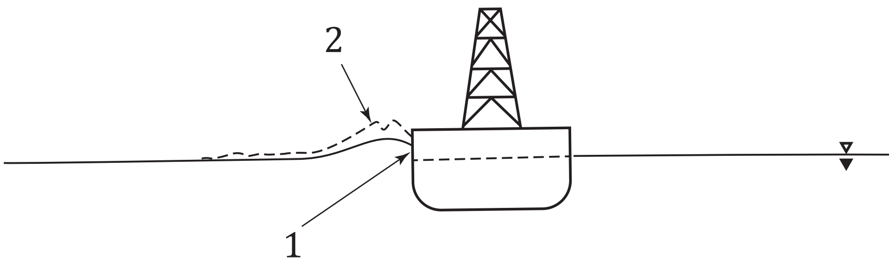
In shallow water, a semi-submersible has a much greater stability in a situation where shallow gas is flowing from the mud line. This is due to the pontoons being widely spaced thus straddling the boil, and being ballasted deeper underwater than the hull of a drill ship and thus further out of the aeration (boil) zone of the gas flow.

Unlike moored drill-ships where the mooring winches are on main deck, moored semi-submersibles have low mooring attachment points (fair-leads are on top of the pontoons), which results in a reduced heeling effect when exposed to an upwelling plume.

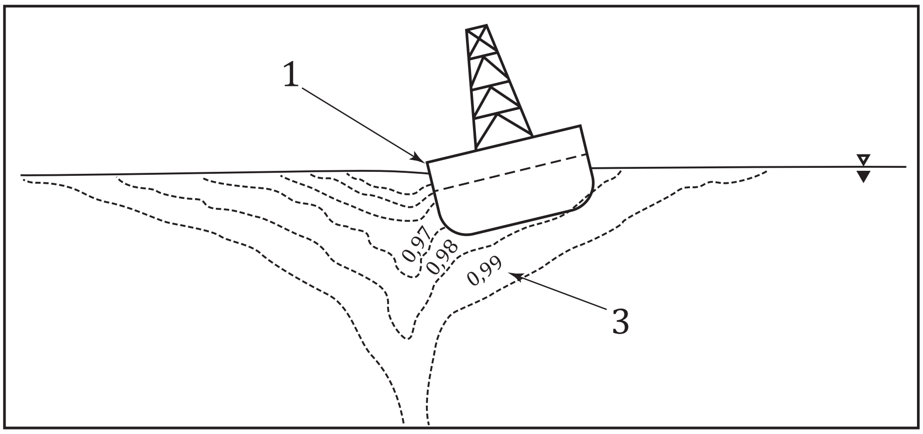
5.3.4 Conclusion

Moored drill-ships shall not be considered for drilling shallow-gas-bearing formations in shallow water depths.

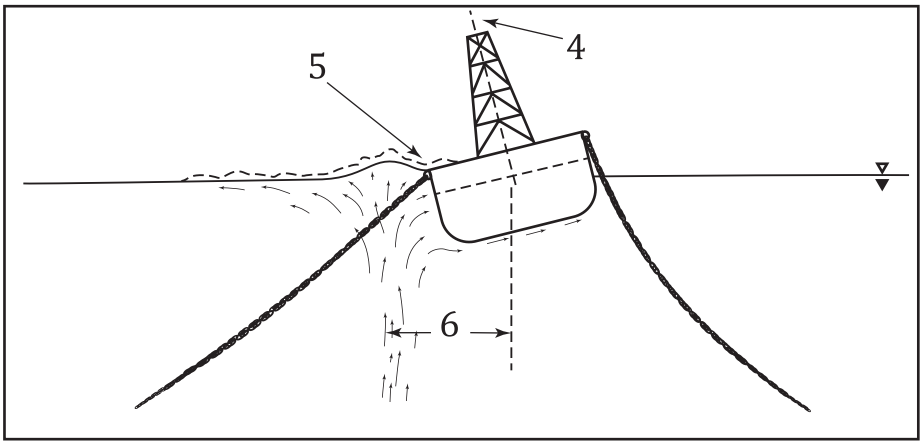
DP drill-ships (water depth permitting) and semi-submersibles (moored or DP) shall be chosen over moored drill-ships.



a) Loss of freeboard from surface displacement



b) Loss of freeboard from density variations



c) Ship-shape pushed off-centre by radial flow components

Key

1 loss of freeboard
2 boil
3 fraction of normal seawater density
4 listing
5 resulting loss of freeboard
6 offset

Figure 11 — Plume effects on ship-shape vessels — Influence on effective trim

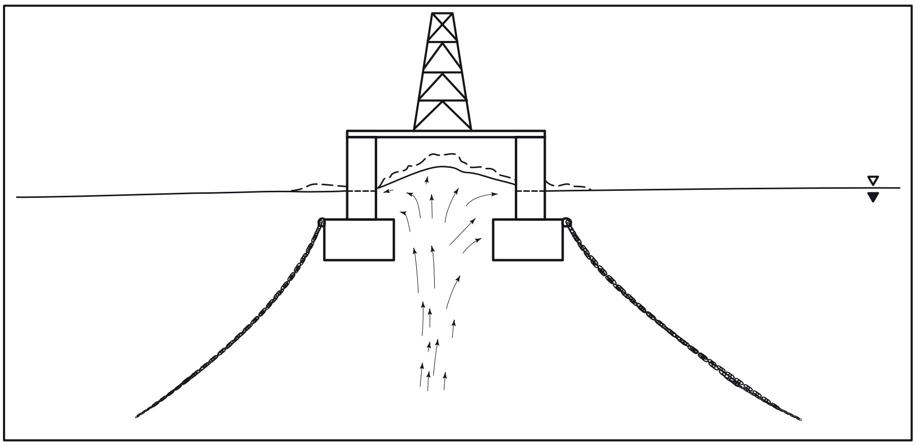


Figure 12 — Plume effects on semi-submersibles — Influence on effective trim

6 Preparation for shallow gas operations

6.1 Call for tender

If shallow gas is expected, it is important to give as many details and specifications in the call-for-tender documents, in order to allow the drilling contractor

— to clearly understand the operator's concern for all major hazards associated with shallow-gas drilling;

— to take all relevant measures to improve, upgrade and later maintain the diverter equipment to the required standards.

6.2 Important issues

When the probability of drilling shallow-gas formations exists, the following points shall be considered:

— proper surveying of the intended drilling location;

— selection of another well surface location if there is any indication of the presence of shallow gas, gas being therefore assumed to be present;

— selection of a drilling rig having:

  — the strongest, safest and most reliable diverter equipment;

  — a competent drilling crew, having past experience in shallow-gas drilling, purposely trained and familiar with the diverter equipment and its proper testing, maintenance, and operation;

— selection of a suitable drilling support for offshore operations, noting that:

  — the use of a bottom-supported rig should be avoided whenever possible (water depth permitting);

  — if a floating rig is required, the safest and most appropriate type of support should be selected, in particular for drilling operations conducted in shallow waters;

— provision by the drilling contractor of comprehensive shallow-gas drilling and emergency procedures;

— provision by the drilling contractor of a comprehensive diverter equipment maintenance program;

— thorough inspection and test (if possible) of the diverter equipment before the contract award.

6.3 Pre-spud checks

6.3.1 Diesel engines and electrical equipment

Engine spark arrestors and air inlet shut-off devices should be in good working order and be connected to the emergency shutdown (ESD) system.

Electrical equipment locations should conform to API RP 500, API RP 505 or to applicable mobile operating drilling unit classification standards.

6.3.2 Kick and loss detection

All kick and loss sensors and alarms should be thoroughly tested. The use of modern downhole early detection systems is mandatory in the shallow-gas context, in order to reduce detection time. Sufficient loss circulation material pills and kill mud volumes should be pre-mixed.

6.3.3 Offshore rescue

The stand-by vessel should be informed in advance about shallow-gas blowout hazards. The stand-by vessel crew shall remain vigilant on radio stand-by and keep the vessel at a minimum safe distance, clear from the vent lines and upwind from the drilling support. For floating drilling operations, the vessel should avoid the axis along which the rig can quickly move-off.

Load transfers to/from supply vessels should be suspended during the shallow-gas phase.

The additional assistance of a tug boat for rapid offset of floating rigs may be requested in the following cases:

— blackout conditions completely disabling a DP vessel power supply;

— mooring line tensions insufficient to move the rig off-location at a safe distance, in particular in shallow waters.

6.3.4 Offshore cooling recommendations

At least one vessel with appropriate fire monitors and spray nozzles should be on site during the shallow-gas phase, in order to protect people on the rig from hazardous heat radiation in case of fire and to allow them to escape safely.

Sprinklers should be provided on the rig over chain windlasses, and be fed with water by an independent pump, e.g. gravity-fed with diesel.

6.3.5 Offshore emergency-release requirements

On moored floating rigs, an emergency-release system for the mooring lines shall be available to allow pay-out of the mooring lines without main power by release of the band/motor brakes. A back-up energy supply (e.g. nitrogen accumulators, battery power pack) shall be available to this end. It should be checked that the sprinkler system for the chain windlasses starts automatically when the emergency-release system is actuated.

A system should also exist to allow control of the chain pay-out speed in case of emergency release, to prevent chains from jumping out of the chain gypsy, from getting caught around the fair-lead, or to avoid the windlass being torn overboard.

Mooring lines shall not be mechanically prevented from being quickly released in a blackout situation (e.g. by a chain stopper or with the clutch engaged) while drilling suspected shallow-gas formations. This situation should be checked and confirmed prior to starting drilling operations.

If possible, the mooring-lines release system should be fully tested before the rig is on payroll.

Control panels for emergency release (e.g. riser connector, riser guide lines) shall be located in a safe area, but not in the cellar deck which might become inaccessible in case of a gas leak.

If a marine riser is in use, sufficient riser tension should be available to lift the marine riser clear of the conductor pipe housing in the event of an emergency disconnect. However (see 4.5.3.1), care should be taken not to apply excessive over-pull to the riser pin connector.

6.3.6 Rig safety equipment

The safety equipment of the entire rig shall be thoroughly controlled, including the following:

— gas detection system;

— fire-fighting and deluge systems;

— emergency generator dedicated functions;

— emergency lighting and communication means.

6.3.7 Safety precautions

Specific safety precautions should be enforced whenever applicable, including (but not limited to):

— keeping the minimum amount of personnel on the rig site;

— prohibiting hot works;

— closing of all hatches (offshore);

— waiting for a good-weather window (floaters);

— waiting for daylight for both shallow-gas drilling and cementing operations (if and when applicable), at least on offshore bottom-supported rigs;

— preventing crew changes during the shallow-gas drilling phase, until the hole has been cased and the casing has been cemented;

— planning for a gas-blocking agent to be added to the cement slurry of the casing run through shallow-gas-bearing formations;

— when drilling riserless the top-hole sections from a floating rig, the ROV should be posted at the seabed observing the returns from the well being drilled.

6.3.8 Diverter system

Prior to drilling a shallow-gas formation, all the diverter system components shall be inspected and tested to ascertain proper installation and function. As a minimum, the following tasks shall be carried out.

— Visually check and verify proper structural mounting of the annular sealing-device assembly, check for possible wear, and if applicable check proper securing of the insert packing element.

— Strongly fasten and secure all loose items which can be jeopardized when subject to severe dynamic forces in case of gas influx.

— Ensure that all vent lines are wide open, if conditions permit, to reduce back-pressures.

— Ensure that any fill-up line which can be exposed to the gas flow is protected with a check valve; this line and check valve shall have a WP equivalent to that of the diverter system.

— Check that the pressures on the control unit are in the permitted ranges.

Once the system is installed, perform a complete function and integrity test as follows.

— Close the diverter on drill pipes.

— Check control functions, proper equipment operating sequence and interlock if applicable, and record response time for each item.

— Repeat the closing test with the accumulator bank alone or the electrical pump alone, and check response time, pressure, efficiency. Control proper starting of the pump when the accumulator pressure has dropped by not more than 10 % of its normal operating pressure.

— Simulate loss of rig air supply to the diverter control system and determine effects, if any, on the diverter system, valves, and back-up systems.

— Ensure that back-up power sources are available in case of total blackout.

— Perform an extensive flow test with sea water at high flow-rate/low pressure for 15 min to 20 min, to detect leaks, vibrations, inadequate fastening and tie-down, line plugging, etc.

— A pressure integrity test should be carried out only on equipment that can withstand such a test, and whenever there is a facility which allows that test to be performed easily.

— On floating operations, ensure that the riser telescopic joint packing(s) have been inspected and replaced as necessary.

On a routine basis, when in primary diverter service (no BOP installed), function tests should be performed daily using the driller's panel to verify that functions are operable. Fluid should be regularly pumped through each diverter line during drilling operations to ensure that they are clear of obstructions at all times.

6.4 Pre-spud meetings

Prior to starting drilling operations, a pre-spud meeting should be arranged with the drilling contractor, the services companies and representatives of the operating company management, in order to:

— review the drilling program and shallow-gas-drilling potential hazards;

— review all preliminary checks related to, among others, the diverter system, kick detection equipment, kill mud volumes, emergency power supply, safety, rescue and emergency equipment, emergency communication systems, mooring equipment if applicable, etc.;

— review specific roles and responsibilities of all subcontractors, e.g. mud logging, mud and cement, marine support (if applicable);

— review pre-spud drills, e.g. kick drill, ESD drill, mooring-line emergency release (if applicable);

— review operator and contractor emergency procedures for response to a shallow-gas flow, and settle any disagreement which might exist on that important subject;

— when applicable (moored drilling-vessel), the contractor should provide the anticipated move-off distances after release of 1, 2, 3 and 4 leeward mooring lines.

Likewise, a pre-spud meeting should be held at rig site with the operator, drilling contractor and all the sub-contractor key personnel in order to:

— remind everyone about the potential hazards of forthcoming operations;

— review specific roles and responsibilities;

— request full compliance for safety rules and drilling instructions;

— request utmost vigilance practice, in particular for permanent well-kick and loss monitoring;

— review the specific shallow-gas influx response procedure;

— review the rig emergency-response procedure, including (if applicable) any specific marine aspects;

— review the applicable abandon-and-rescue procedures.

6.5 Pre-spud drills

Shallow-gas flows generally develop quickly, can be difficult to detect early, and can release high volumes of gas due to highly permeable formations or to the very large expansion of near-surface gas. Likewise, the inadvertent entry of gas into a marine riser can be difficult to detect.

All concerned personnel should therefore be familiar with the diverter system components and installation, and should be capable of reacting quickly and efficiently to potential situations requiring use of the diverter.

Pre-spud drills should be conducted so as to:

— check personnel preparedness and acquaintance with the diverter equipment and with the emergency procedures;

— detect failures, leaks and/or malfunctions;

— ensure that gas can be properly diverted;

— ensure that the site can possibly be abandoned under blackout conditions.

These drills should include:

— pit drills;

— emergency drills, including ESD activation, check of functions actually running with the emergency power supply, activation of fire-fighting team and equipment, testing of mustering-and-abandon procedures and efficiency, testing of the alertness and response of rescue supports;

— testing of riser subsea hydraulic connector release (floaters, weather permitting);

— testing of mooring-lines emergency release (floaters) during a pull-off test.

Any defect or problem with equipment or personnel identified during any of these pre-spud drills should be immediately reported and dealt with before drilling is permitted to start. Thereafter, drills should be conducted at appropriate intervals to ensure personnel are capable of quickly and competently reacting to situations requiring use of the diverter.

Drills should be systematically documented and analysed to identify areas where improvement is required. Follow-up on problem areas identified in the drills should be completed and documented. Emergency plans, training, and drills should be kept up-to-date and changed as conditions change.

6.6 Preparing the response to a shallow-gas flow

6.6.1 General

Most companies dealing with shallow-gas drilling have their own in-house policy regarding the specific response to be given to a shallow-gas influx. However, opinions differ significantly throughout the drilling industry regarding the subject, due to the complexity of the problem and the large number of associated uncertainties. Hence proposed techniques for handling well kicks are extremely diverse.

None of these techniques can pretend to be of general application regardless of the circumstances, and it should be emphasized that a particular technique cannot be indiscriminately applied.

Adequate response to a shallow-gas flow depends on a large number of parameters associated, among others, with the borehole size and depth, the gas-bearing-zone characteristics and productivity, the dimensions of the rig surface diverting equipment, the rig pumping capacities, etc.

Hence, it is the management responsibility of both operator and drilling contractor to fully determine in advance what could and should realistically be done. Each specific situation should be individually designed.

It is important to keep in mind that shallow-gas kicks are extremely fast-developing events. Most shallow-gas disaster reports disclose that not more than 15 s to 20 s separate the first surface flow indications from a blowout condition. Surface events seldom develop into an easily controlled kick situation, but swiftly turn into an uncontrolled one. Consequently, the proposed well-control procedures shall take these facts into account and be extremely realistic.

Subclauses 6.6.2 and 6.6.3 give a few reminders and recommendations associated with shallow-gas well control.

6.6.2 Reminders

Prior to designing a well-control method, some specific and important aspects associated with shallow-gas drilling should be kept in mind.

— A shallow-gas zone is usually abnormally pressured; this is associated with the height of the gas column present in the gas-bearing formation between the point of bit entry and the top of the gas-water contact. This phenomenon can be worsened by the natural dip of the gas-bearing layer, the effective thickness becoming much bigger than the true thickness (see Figure 13).

— The pressure or thickness of a shallow-gas zone is not always predictable by the operator. The formation pressure can actually exceed the maximum acceptable drilling-fluid hydrostatic pressure, the MW limitation being imposed by mud loss consideration. Once the zone is penetrated, the inflow cannot be prevented.

— Any permeable formation that becomes under-balanced will flow. In particular, if a shallow-gas zone is penetrated offshore while utilizing only seawater and circulation back to the sea-bed elevation, the gas zone will most likely flow (confirmed by several blowout reports).

— When surface-diverting a shallow-gas flow (on- or offshore), entrained formation particles can lead to erosion and rapid failure of surface equipment, should the latter not be purpose-designed to cope with these specific hazards.

6.6.3 Basic well-control aspects

6.6.3.1 Actions to be taken on land rigs and bottom-supported marine structures

Most people should be evacuated as soon as possible after shallow-gas kick detection, except for essential personnel, who will attempt to stop the flow and contain it as long as it is safe to do so. It is indeed irresponsible to expose people to highly probable fire and explosion hazards.

If practically feasible, a tentative well kill should be attempted immediately with heavy kill mud and the maximum pumping rate available, after the diverter system has been activated, to try to stop the gas flow downhole, prior to complete well unloading.

However, it should be kept in mind that:

— gas expansion close to the surface is extremely fast, thus reducing significantly the time from gas influx to its surface appearance;

— in a large and shallow borehole, production of frictional pressure losses sufficient to stop an established gas flow is unlikely and hypothetical.

If the diverter system fails, or if bubbling appears around the drilling unit, the rig should be abandoned or moved off-location if at all possible.

6.6.3.2 Actions to be taken on floating rigs

a) Drilling with a riser.

— Unless a reliable diverter system is available, bringing gas to the surface should preferably not be contemplated.

— The riser should preferably be disconnected immediately.

— The drilling vessel should be moved off-location if gas flow is confirmed (bubbling at surface).

b) Drilling riser-less.

— Attempts to control the flow can be conducted as long as it is safe to do so.

— The drilling vessel should be moved off-location if surface conditions become unsafe.

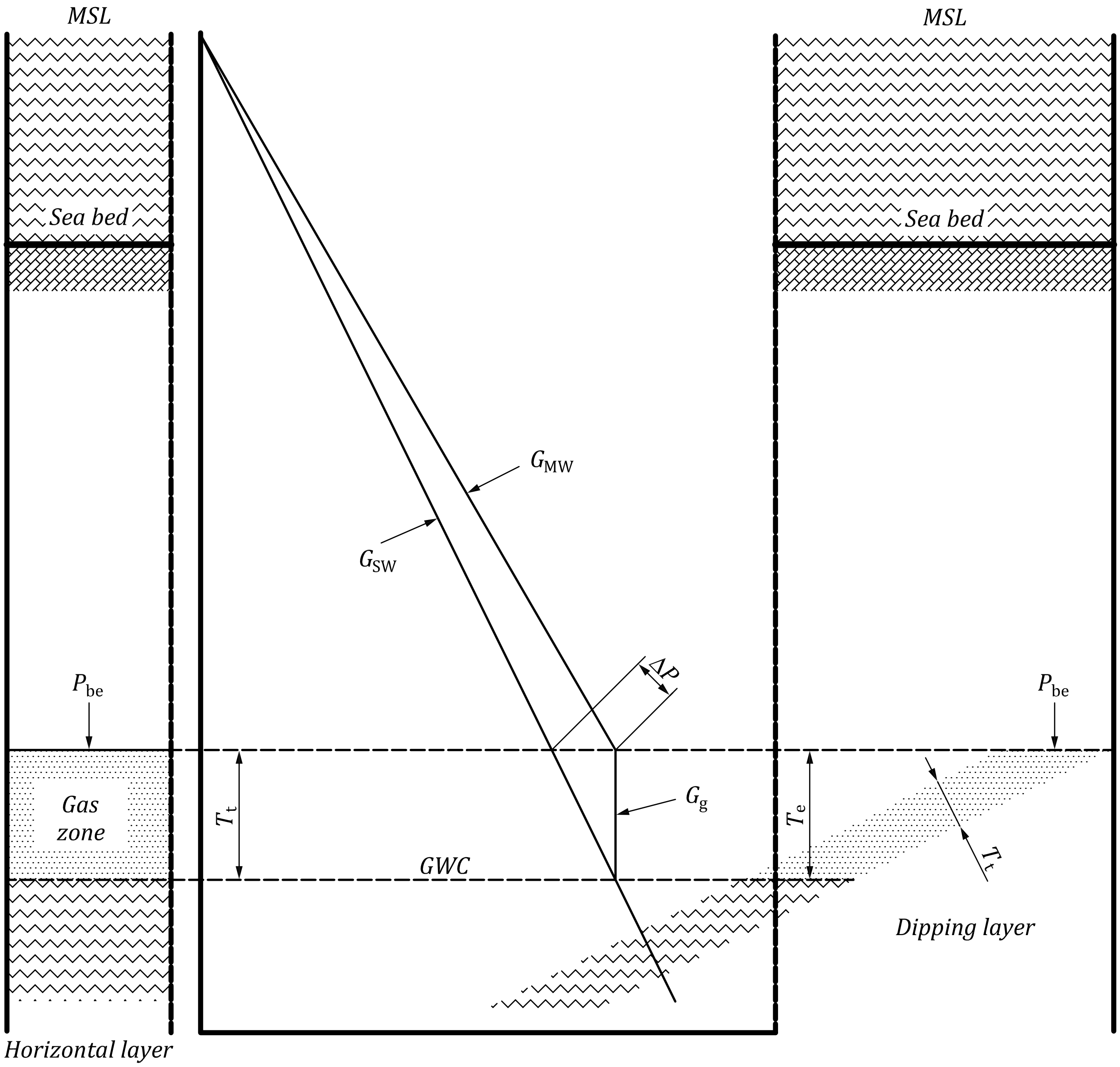
c) Using a subsea (or seabed) diverter.

— The diverter should be closed immediately, as soon as the gas influx has been detected.

— If practically feasible, a well kill should be attempted with heavy kill mud, to try to stop the gas flow downhole as soon as possible.

— The well-control operations should be stopped whenever surface conditions can jeopardize people and rig safety. The well should then be secured with the shear rams and the vessel moved off-location.

For more details regarding shallow-gas well control aspects, see API RP 64:2001, Appendix A.



Key

G_g	gas gradient
G_{SW}	seawater gradient
GWC	gas-water contact
G_{MW}	required mud gradient
MSL	mean sea level
P_{be}	point of bit entry
ΔP	overpressure
T_t	true thickness
T_e	effective thickness

Figure 13 — Cause of overpressure — Effects of thickness and natural dip

7 Diverter system inspection and maintenance

7.1 General

A schedule for routine inspection and maintenance of diverter systems equipment should be prepared and maintained by the rig operating personnel. Specific guidelines for each diverter component or sub-system should be based on installation, operation and maintenance manuals provided by the equipment manufacturer.

7.2 Maintenance

— All diverter equipment shall be maintained with original equipment manufacturer's (OEM) genuine or approved spares and shall be operated and tested in accordance with that manufacturer's recommended procedures. Major repairs and overhaul of diverter equipment shall be performed either by the OEM or an alternative provider, but then only when approved by the OEM.

— Carry out weekly maintenance on the control panel, including checking various fluid levels and cleaning air strainers, pump strainers and filter elements. Tightening of packing and lubrication of power-actuating cylinders should be performed on a weekly basis. The precharge pressure in the accumulator bottles should be checked at this time.

— Calibrate and tag control-system pressure gauges at intervals not exceeding one year.

7.3 Inspection and testing

Diverter systems are just as important as all other well-control equipment, and shall therefore be subject to inspection and testing.

Consequently:

— All diverter equipment shall be of dimensions and pressure rating appropriate for the application.

— Visually inspect the elastomer components of the system after each test to verify that they are in good working condition. They should be replaced when their proper functioning is questionable due to damage, wear and/or age.

— During diverter function tests, observe all components of the diverter system including the diverter, valves, valve actuators, piping, and control panel to verify that there are no leaks in the system. If a leak is discovered, it should be repaired immediately.

— Visually check control hoses, tubing, vent-line piping support brackets, targets, valves, fittings, etc., on a routine basis and carry out any necessary repairs immediately.

— A visual inspection, a body-pressure test and a full-function test shall be carried out once a year on a diverter test stump at surface, in accordance with the manufacturer's specification for such a test. Results of the inspections and tests, including follow-up, shall be documented, providing full traceability and be part of the formal service history.

— At least every five years, the diverter system components shall be inspected for repair or remanufacturing by the OEM or OEM-approved service provider. Upon completion of the inspection, the OEM shall provide a Certificate of Conformance (COC).

7.4 Diverter system piping

The wall thickness on all undesirable turns and bends (if any) in the diverter system piping should be checked at least annually and after each use of the system to divert a well kick. Erosion of metal from the turns and bends can be severe if sustained flows of gas-associated solids are diverted through the system.

7.5 Manufacturer documentation

Installation, operation and maintenance manuals furnished by the manufacturers of the various components of the diverter system should be readily available for training, reference, and use by maintenance personnel.

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