Tripping Operations with Surface Back-Pressure Managed Pressure Drilling with subsea Blowout Preventer

API RECOMMENDED PRACTICE 79-3

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Introduction

These guidelines (recommended practices) represent a composite of the practices employed by various operating companies, service companies, and drilling contractors in overbalanced tripping operations. In some cases, a reconciled composite of the various practices employed by these companies was used.

Recommended practices set forth herein are considered acceptable for accomplishing the job as described; however, they do not present all the operational practices that can be employed to accomplish the same objectives. Individuals and organizations using this standard are cautioned that operations must comply with requirements of federal, state, or local regulations. These requirements should be reviewed to determine whether violations can occur.

The objective of these guidelines (recommended practices) within is to assist the oil and gas industry in promoting personnel safety, public safety, wellbore integrity, and preservation of the environment for offshore drilling operations with subsea BOP.

It provides information and guidance on procedures related to tripping activities with surface back-pressure managed pressure drilling with subsea Blow Out Preventors (BOPs). These operations have inherent hazards and risks and therefore require detailed care and attention to improve reliability and reduce risk to acceptable levels. The principles and recommendations have general relevance, regardless of classification, and are applicable to onshore tripping operations.

Competent and technical judgment must be used in combination with these recommendations. Each operator, service provider, and drilling contractor involved in tripping operations should review and apply these guidelines (recommended practices) according to their own policies and procedures.

Overbalanced tripping operations are being conducted with full regard for personnel safety, public safety, and preservation of the environment in such diverse conditions as urban sites, wilderness areas, very hot barren deserts, cold weather areas including the arctic environment, and wildlife refuges. As tools and equipment continually improve and develop, the technology has been applied in many geologic formations, including oil and gas reservoirs and on sour wells, thus driving the need for globally accepted standards and safe operating best practices.

The purpose of this document is to provide information and to recommend practices and procedures for planning, equipment considerations, and execution of tripping operations in overbalanced wells. It is also intended to assist operators, service providers, and drilling contractors in developing their own internal rig-specific procedures for safe tripping operations.

1 Scope

This document provides guidelines for tripping operations with surface back-pressure managed pressure drilling in accordance with API 92S. This document applies only to drilling rigs with subsea blowout preventers.

This document does not address operations with service gas (e.g., nitrogen) injection.

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 Standard 53, *Well Control Equipment Systems for Drilling Wells*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1
accumulator
Pressure vessel charged with inert gas and used to store and deliver hydraulic fluid under pressure.

3.1.2
alarm
An audible and/or visual indication to the user that an equipment malfunction, process deviation, or other abnormal condition requires a prompt response from the user.

3.1.3
alarm flooding
An alarming condition determined by the user, during which the alarm rate is greater than the user's ability to effectively manage.

3.1.4
alarm shelving
The ability for the user to temporarily prevent the audible and/or visual reporting of an active alarm for a period of time.

3.1.5
alarm suppression
The ability for the user to inhibit audible and/or visual reporting of an alarm.

3.1.6
annulus
Annular space between the outer diameter of the drill string and the inside diameter of the hole being drilled, or casing string set in the well.

3.1.7
blowout
An uncontrolled flow of well fluids, formation fluids, or both, from the wellbore.

NOTE An uncontrolled flow underground is also considered a blowout.

3.1.8
blowout preventer
BOP

Sealing ram or annular type device, which is within the scope of API 16A, installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars or in an open hole during well drilling, completion, and testing operations.

3.1.9
bottom-hole assembly
BHA
Assembly composed of the bit and a combination of specialized tools and subs that is connected to the bottom of a string of drill pipe.

NOTE Specialized tools and subs include components such as stabilizers, reamers, drill collars, measurement and formation evaluation tools, directional drilling tools, etc.

3.1.10
bottom-hole pressure
BHP
A pressure exerted by a column of fluid contained in the wellbore plus or minus annulus friction pressures caused by pipe movements.

3.1.11
casing
Pipe installed in the wellbore and cemented or secured by some other means.

3.1.12
casing seat
The depth to which casing is set.

3.1.13
choke manifold
Assembly of valves, chokes, gauges, and lines used to control the rate of flow and pressure from the well when the blowout preventers are closed.

3.1.14
circulate
Pumping fluid from the surface through the drill string with fluids returning to the surface through the annulus.

NOTE This is commonly called either “circulating” or “forward circulating” with the reverse practice labeled “reverse circulating.”

3.1.15
critical equipment
An engineered system or component determined to be essential in preventing the occurrence of or mitigating the consequences of an uncontrolled event.

NOTE Such equipment can include vessels, machinery, piping, blowout preventers, wellheads, and related valving, flares, alarms, interlocks, fire protection equipment, and other monitoring, control, and response systems.

3.1.16
drill gas
background gas
Formation gas entrained in the circulating mud.

3.1.17
drill pipe safety valve
Full-opening valve located on the rig floor with threads to match the drill pipe connections or other tubulars in use.

NOTE This valve is used to close off the drill pipe to prevent flow and can be crossed over to fit other connections and sizes of tubulars being installed in the well (commonly referred to as "full-opening safety valve").

3.1.18
drill string
The sum total of all components from the drill bit to and including the drill pipe safety valve at surface.

3.1.19
dry displacement
A condition that can occur

a) when tubulars are pulled from the wellbore and either do not contain drilling fluids inside the internal capacity of the tubular, or

b) when tubulars are pulled wet from the wellbore and the drilling fluid routed by the mud bucket drains into the same tank the wellbore is being filled from.

3.1.20
Dynamic flow check
The practice of observing a well while connected to the annulus and circulating to determine if the resulting bottom hole pressure maintains an overbalanced wellbore condition; i.e., there is no continuing self-sustained formation flow.

3.1.21
equivalent circulating density
The sum of pressure exerted at a specific depth by hydrostatic head of fluid, drilled solids, and friction pressure losses in the annulus expressed as a density.

3.1.22
flow check
The practice of observing a well to determine if it is static; i.e. there is no continuing self-sustained flow after stopping pumping or moving of the drill string.

3.1.23
flow line
Piping that exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits.

3.1.24
flow sensor
A device installed in the flow line to measure flow returning from the wellbore.

3.1.25
fluid density
The weight per unit of fluid.

NOTE Expressed in U.S. customary units in pounds per gallon (lb/gal), and in International System of Units (SI) in kilograms per cubic meter (kg/m^3).

3.1.26
hazard
A source, situation, or act with the potential to produce harm in terms of injury, ill health, pollution, or damage to or loss of assets.

3.1.27
hydrostatic barrier
Hydrostatic pressure of a fluid column sufficient to prevent formation fluid influx into the wellbore.

3.1.28
hydrostatic pressure
Pressure that is exerted at any point in the wellbore due to the weight of the column of fluid above that point.

3.1.29
hydrostatically overbalanced
The condition in which the hydrostatic pressure of the well alone exceeds the pressure in an exposed formation.

3.1.30
ice plug
An obstruction formed by a circulation medium freezing inside a tubular.

3.1.31
influx
A quantity of formation fluids present in the wellbore.

3.1.32
inside blowout preventer
IBOP
A 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.

3.1.33
kick
An unplanned, unexpected flow of liquid or gas from the formation into the wellbore.

3.1.34
lost circulation
lost returns
The loss of drilling fluid to the formation.

3.1.35
management of change
MOC
A change control process used to manage unplanned changes that are not like-for-like or kind-for-kind in people, organization, practices, procedure, equipment, or materials in the approved plan or guideline.

NOTE An MOC process ensures that changes (and the resulting risks, if any) are reviewed, evaluated, approved, and documented by the responsible and accountable parties (prior to initiating or continuing the operation).

3.1.36
mud bucket
Device used to enclose pipe connections to control and collect fluid released when a joint or stand of pipe containing liquid (wet string) is unscrewed.

3.1.37
Negative test
A test in which the hydrostatic pressure is reduced such that the net differential pressure direction is from the formation into the wellbore.

3.1.38
operator
The lease owner or their designated agent who is responsible for the overall operation of the lease.

3.1.39
overbalance
The condition in which the pressure in the wellbore exceeds the pressure in an exposed formation.

3.1.40
pit volume indicator
A device installed in the drilling fluid tank to register the fluid level in the tank.

3.1.41
pit volume totalizer
PVT
Device that combines all the individual pit volume indicators and registers the total drilling fluid volume in the various tanks.

3.1.42
primary well barrier
The first well barrier that prevents flow from a formation.

NOTE 1 For conventional operations, the primary well barrier is the drilling fluid hydrostatic column.

NOTE 2 This term is referred to as "primary well control" in API 59.

NOTE 3 This includes the individual equipment items and components that form the primary well barrier per API 92M.

3.1.43 primary well barrier element
The individual equipment items and components that form the primary well barrier.

3.1.44
risk
The probability that a specified undesired event will occur.

3.1.45
risk assessment
A systematic process to identify the potential causes of harm or hazards, and the precautions that can be taken to prevent or mitigate the hazards.

3.1.46
rotating control device
RCD
Drill-through equipment designed to allow the rotation of the drill string and containment of pressure using seals or packers that seal against the drill string (drill pipe, casing, etc.).

NOTE Commonly referred to as "rotating head."

3.1.47
secondary well barrier
A device (for example, a blowout preventer) or system that prevents or controls flow from a well when the primary barrier is insufficient.

3.1.48
secondary well barrier element
The individual equipment items and components that form the secondary barrier.

3.1.49
shut in
To close in a well with the blowout preventer.

3.1.50
slug
A denser volume of mud pumped into the drill string to displace mud out of the upper part of the drill pipe before pulling tubulars out of the hole, thus keeping the upper stands of tubulars empty of fluid.

3.1.51
space-out
A procedure conducted to position the drill string so that no kelly or tool joint is opposite a set of preventer rams.

3.1.52
stripping
Inserting or removing the drill string through a sealed annular control device.

3.1.53
surging
The increase of pressure in the wellbore caused by friction between a drill string being lowered into the wellbore and the annular fluid column or when the mud pump is brought up to speed after starting.

3.1.54
swabbing
The reduction of pressure in the wellbore caused by friction between a drill string being pulled upward and the annular fluid column.

3.1.55
Swab margin
A Swab margin is additional pressure applied to the well to counter swab effects while tripping out.

3.1.56
tour
Designates the work shift of a rig crew.

NOTE Pronounced as taủ(-ə)r.

3.1.57
trip margin
The amount by which the current mud density provides an element of overbalance and compensates for the effects of swabbing.

3.1.58
trip tank
Tanks calibrated to permit accurate measurement of volumes of mud pumped into and/or displaced by the drill string during tripping operations.

3.1.59
tripping
The process of pulling a series of tubulars out of and/or lowering tubulars in a well.

3.1.60
tubulars
Drill pipe, drill collars, tubing, and casing.

3.1.61
underbalance
A condition where the pressure exerted in the wellbore is less than the pore pressure in any part of the exposed formations.

3.1.62
weighted pill
A denser volume of fluid pumped into the drill string or annulus to produce additional hydrostatic pressure in the wellbore.

3.1.63
well barrier
Envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation, or to the environment.

3.1.63
well barrier element
Physical component (mechanical or nonmechanical) that can be combined with other dependent items to form a well barrier.

NOTE This includes hydrostatic, mechanical, or solidified chemical materials (usually cement).

3.1.64
well control
Activities implemented to prevent or mitigate an unintentional release of formation fluids and gases from the well to its surroundings.

3.1.65
well control drill
A training method to determine that rig crews are familiar with operating practices to be followed in the use of blowout prevention equipment; a “dry run” of blowout preventive action.

3.1.66
well control equipment
Equipment within the scope of API 16A, API 16C, and API 16D and the supporting auxiliary equipment referenced in the scope of this document.

3.1.67
wet displacement
A condition when tubulars are pulled from the wellbore and still contain drilling fluids inside the tubular.

3.2 Acronyms and Abbreviations

BHA bottom-hole assembly
BOP blowout preventer
DIV downhole isolation valve
IBOP inside blowout preventer
ERP emergency response plan
IBOP inside blowout preventer
MOC management of change
MPD managed pressure drilling
PVT pit volume totalizer
PWD pressure well and drilling
RCD rotating control device
SBP surface back pressure

4 Tripping Operations Overview

4.1 General

In tripping operations with surface backpressure (i.e., stripping), it is particularly important to prevent unplanned influx incidents that can reduce the effectiveness of the primary well barrier.

Prior to performing stripping operations, company- and rig-specific procedures should be developed, documented, and agreed upon by the drilling contractor and the operator to ensure that tripping speeds and surface backpressures are within predefined operational and equipment limits.

Influx incidents should be categorized and reported in accordance with local operator policy and be consistent with regulatory body requirements. If measurements or sensors indicate a kick or the presence of formation fluids is observed at surface, stripping operations should be suspended, and a safe course of action determined while observing the well.

Once stripping operations have ceased, the well should be in an overbalanced condition.

The following methods may be utilized to maintain the integrity of the primary barrier by always keeping an overbalanced condition while tripping and during transients. This includes individual or combined methods listed below.

4.2 Tripping methods

Tripping and stripping operation in and out of the hole can be done through different methods. Each method present pros and cons that must be evaluated prior to the operation.

4.2.1 Roll over to hydrostatically overbalanced fluid to enable conventional tripping.

Description: Rollover mud using MPD techniques to an overbalanced mud weight. Remove RCD bearing and trip conventionally.

Considerations:

- Rollover can be done at TD, casing shoe or any other point of interest.
- Rollover can be performed at multiple stages and make use of the booster pump to avoid fracturing the formation.
- Conventional considerations for tripping such as swab margin, well bore stability, etc… still apply.
- PWD tools can provide feedback on hydraulic models to ensure proper margins.
- Requirements for additional wellbore pressure due to swab effects
- Rollover can be a complete displacement or partial displacement.

Pros:

- Conventional trip out with common industry practices, such as removes stripping speed limit of sealing element, reduces wear on sealing bearing.

Cons:

- May require slower tripping to control swab in narrow margin wells.
- Requires pit space for mixing fluids for rollover of the active system.
- May result in losses in narrow margin wells.
- Disables early kick detection and dynamic influx management response available with MPD equipment.
- Longer exposure time of open hole.
- Fluid management and tracking can be complex during rollover.

- In case of partial displacement, multiple fluids in the wellbore will impact pressure profile in the annulus and complicate pressure management.

4.2.2 Hold SBP while hydrostatically overbalanced

Description: the hydrostatic of fluid in the well is above pore pressure or wellbore stability, but the tripping is done stripping through the sealing element while applying SBP.

Considerations:

- The swab margin can be replaced with SBP.
- Various mud rollover strategies depend on the application or wellbore conditions.
- May need to close the BOP blind rams to isolate the well when BHA above the BOP.
- The sealing element's remaining life expectancy compared to the tripping length.

Pros:

- The monitoring and kick reaction can be done by the MPD system.
- Enhanced annulus pressure profile control and reduction on well pressure variation.
- May allow rollover on narrow margins.

Cons:

- Reduced tripping speeds.
- Potential for formation breakdown.
- Complexity of the operation may be increased depending on well margin and conditions.

4.2.3 Place pill in the riser

Description: A new fluid will be inserted in the riser to add hydrostatic pressure to eliminate or reduce SBP.

Considerations:

- The booster line, a sub in the string or other methods can be used to replace the fluid in the riser.
- Mud interface tracking, difference in wellbore capacity and the difference in density have impact on wellbore annulus pressure profile.
- Depending on the hydrostatic pressure added there still might be the need to close the BOP blind ram to isolate the well.
- In case the entire riser fluid is displaced with new fluid it is an option to use the booster pump. In operations where the riser fluid is displaced partially the use of booster pump will impact the hydrostatic annulus pressure profile.
- Requirements for additional wellbore pressure due to swab effects

Pros:

- Conventional trip out with common industry practices.
- Removes stripping speed limit of RCD element
- Reduction in wear of the sealing bearing/element due to reduced SBP

Cons:

- A narrow margin well might have losses with this technique.
- Heavy fluid will fall into lighter fluid leading to mixing of fluids and less control over annulus pressure profile compared to other methods.
- May require slower tripping to control swab in narrow margin wells.
- Requires additional pit space for mixing fluids for rollover.
- Possible complication in pill height management, auto-fill floats, and cementing operations when running pipe into the hole.
- Disables early kick detection and dynamic influx management response available with MPD equipment when the sealing element is removed.
- Additional operation for riser displacement when reentering the riser.

4.2.4 Close the BOP blind ram after passage of BHA

Description: Trip above the BOP with a closed blind ram and depressurized riser, the pressure in the well is held by the blind ram. When the string is below the BOP SBP must be maintained to keep the well overbalanced.

Considerations:

- BOP configuration, such as, but not limited to: redundancy of blind shear rams, valve and lines locations,
- BHA length has to be shorter than the water depth,
- pressure limitations,
- differential pressure limitations for valve opening,
- plan to monitor below rams and maintain pressure within the limits of the operation.
- Shallow water scenarios might have pipe light issues.
- The sealing element shall have a life expectancy greater than the tripping length.
- Procedure for pressure equalization prior to opening BOP.

Pros:

- Eliminates the necessity of mud roll over.
- Reduces exposure time of the open hole.
- Generally faster trip in and trip out.
- Simplify fluid management at the surface and reduces risk of fluid contamination.
- No issues with fluid swapping from higher density fluids spotted above lower density fluids such as when riser caps are used.
- Maintains MPD equipment usage during trip out of hole for early kick detection and dynamic influx management response.
- After BOP is closed, the well pressure and riser must be monitored.
- Can be used to maintain bottom hole pressure in tight margin scenarios.
- Ability to maintain the pressure with limits eliminating fluid expansion by circulating at surface while maintaining well pressure.

Cons:

- Risk of dropped pipe on close blind ram while tripping above a closed BOP
- Loss in seal at BOP can result in reduction in bottom hole pressure
- Trip out to above BOP can be slower with RCD element installed due to RCD tripping speed limits

4.2.5 Close downhole isolation valve

Description: With a downhole isolation valve (DIV) previously installed in the well, the well can be isolated after the string is above the (DIV).
Considerations:

- A DIV is usually installed in the lowest casing string possible. It can be closed when there is no downhole assembly or equipment across it thus enabling wellbore isolation.
- After the DIV is tested there is no need to kill the well with other methods.
- A DIV allows the well to be closed below the BOP; the BOP then remains as the secondary well control device.
- These types of valves come in various configurations that can be mechanically or hydraulically activated and be single or multiple use.
- The DIV can be designed with similar burst and collapse ratings as the casing, but this should be confirmed during planning.

Pro:

- Once the BHA passes the DIV and it closes and a negative test, tripping can proceed with or without the RCD in place.

– Tripping without the RCD allows faster tripping speeds and reduces wear on the RCD.
– When performing MPD, wireline, or other operations, it allows the wellbore fluid to remain unchanged, which reduces time in commencing those operations to perform mud roll overs; as such, there is no mingling of different types of fluids in the well thus this reduces complexity of drilling fluids handling.

Cons:

- Added complexity of the well
- Risk of failure or leak
- Impossibility of maintenance or recovery
- Risk of damage with dropped objects
- A DIV that is only one way may require pressure from below the valve to close; if the weight above the valve is higher than below the valve, there is risk of the valve opening and allowing flow into the well.
- The valve components may restrict the internal ID of the casing, reducing the through-bore diameter.
- DIVs have a larger outside diameter than the casing in which it is installed and therefore limits the size of the previous casing ID that can be installed before it affects well architecture design; this also needs to be factored into cementing operational planning due to reduced clearance around the DIV.
- Specific DIV designs may have other specific limitations that should be taken into consideration during operational planning.

5 Planning

5.1 General

5.1.1 To safely manage inherent risks, tripping operation task and work instruction plans should include:

a) shut-in procedures;

b) contingency plans;

c) evacuation plans;

d) kill sheets and trip sheets;

e) surface back pressure (SBP) schedule and limits;

f) stripping speed schedule and limits;

g) rotating control device (RCD) element integrity and valve alignments; and

h) mud weight (MW) schedule and condition.

5.1.2 A management of change (MOC) process (or equivalent) should be used to manage the risks associated with unplanned changes or events that deviate from planned tripping operations according to company policies and procedures.

5.2 Risk Assessment

5.2.1 Each company should evaluate the workplace hazards and risks and develop and implement measures to manage identified risks. See API 54 for additional guidance on occupational hazards related to tripping operations such as, but not limited to, the following:

a) housekeeping;
b) egress route;
c) dropped objects;
d) tubular handling;
e) V-door opening;
f) safety clamps;
g) Hydrate formed ice plugs in tubulars.

5.2.2 The level of risk assessment required to complete an operation or task safely is determined by several factors including, but not limited to, type and complexity of the operation or task, number of personnel involved, and competencies of persons involved.

5.2.3 Job tasks, including potential simultaneous operations and critical equipment installation and removal, shall be planned and risk assessed before operations commence. Planning and risk assessment shall be communicated during a safety meeting with the crew and other involved personnel.

5.2.4 Each company should determine the best method to conduct a risk assessment appropriate for the task that may include, but is not limited to, a documented process, a visual or verbal process, the job safety analysis, or other company-specific process to recognize risk.

5.2.5 For hazards that cannot be eliminated or avoided, the risk should be mitigated as low as reasonably practicable.

5.2.6 Efforts should be made to prevent identified hazards through an appropriate hierarchy of controls as follows:

a) elimination;
b) substitution;
c) engineering controls;
d) administrative controls;
e) personal protective equipment.

5.2.7 All personnel shall have the authority and obligation to initiate Stop Work when an identified risk cannot be mitigated, an unsafe act or condition is observed, or there is uncertainty or confusion about work instructions.

5.2.8 The operator and contractor shall be responsible for developing, documenting, and communicating site-specific emergency response plans (ERPs). These plans should include emergency responses, and evacuation and egress during well blowouts. Refer to API 54 for additional information.

5.2.9 Documented handover notes detailing well-, safety-, and equipment-related information should be provided to oncoming crews prior to shift changes.

5.3 Contingency Plans

5.3.1 Well control contingency plans related to tripping operations should be developed to address circumstances that can deviate from the original plan. These plans should be communicated and understood by the appropriate personnel.

5.3.2 Well control contingency plans at a minimum should address the following:

a) methods to identify a failed primary well barrier and procedures to secure the well;

b) identifying surface equipment needed to secure the well;

c) identifying surface equipment and procedures needed to restore the primary well barrier;

d) identifying length, dimensions, and spacing in the drill string or bottom-hole assembly (BHA) that can potentially compromise the ability of the blowout preventer (BOP) to seal and secure the well.

6 Equipment

6.1 General

6.1.1 Equipment installation, commission, operation, maintenance, inspection, and removal should follow the original equipment manufacturer's or current equipment owner's procedures or recommended practices.

6.1.2 A maintenance, inspection, testing program, or a combination thereof, should be established and documented to maintain the ongoing integrity of the following equipment to function on demand:

a) BOP(s);

b) top drive equipment;

c) drill pipe safety valves;

d) non-return valves (NRV);

e) MPD Riser joint

f) Telescopic joint;

g) Sealing assembly;

h) surface valves (e.g., isolation valves and check valves);

i) Surface MPD lines;

j) pit volume indicators;

k) trip tank;

l) mud bucket and drain lines;

m) mud/gas separator;

n) Overboard lines;

o) MPD surface lines and hoses;

p) MPD riser joint lines;

q) well control choke manifold;

r) MPD choke manifold;

s) pressure relief valves (PRV);

t) flow meters (e.g., Coriolis meters and flow paddles)

u) Booster lines ;

v) MPD accumulator;

w) BOP remote;

x) auxiliary escape;

y) hoisting tools;

z) hooks;

aa) elevator links (bails);

bb) elevators and related equipment;

cc) tag lines and hand-free devices;

dd) rotary table;

ee) drill string handling equipment;

ff) lift subs;

gg) drill collar clamps;

hh) Compensators

ii) weight indicators;

jj) communications systems.

6.1.3 An MOC process (or equivalent) should be conducted to address deviations that negatively impact the performance and reliability of the equipment listed in 6.1.2.

6.1.4 Prior to and during tripping operations, critical equipment should be monitored to ensure that it is functioning within operating limits.

6.1.5 Well control equipment shall be installed, inspected, and maintained in accordance with API 53.

6.1.6 The pit volume totalizer (PVT) and recording devices shall be available in accordance with API 53.

6.2 Valves

6.2.1 Drill String Valves

6.2.1.2 On a top-drive rig, a minimum of two valves shall be installed, the lower of which should be a safety valve suitable for emergency stripping into the wellbore during which the NRV has failed.

NOTE On a top-drive rig, safety valves are also commonly known as a “top-drive inside blowout preventer (IBOP).”

6.2.1.3 A lower valve wrench shall be readily available on the rig floor or in the driller’s cabin. The lower valve (top-drive) should be actuated manually daily to verify free motion.

6.2.1.4 A drill pipe safety valve shall be readily available on the rig floor and equipped with crossovers, if necessary, to screw into the current drill string member in the rotary table.

6.2.1.5 The drill pipe safety valve shall be stored in an open position with wrench accessible on the rig floor.

6.2.1.6 In addition to the drill pipe safety valve, there shall also be an IBOP stored on the rig floor available for installation in the drill string.

6.2.1.7 A non-ported NRV shall be installed in the drill string and should be as close to the bit as practical, with at least one NRV above the circulation subs and reamers if present.

6.2.1.8 If the mud system used is hydrostatically underbalanced, a minimum of two NRVs should be installed in the drill string.

6.2.1.9 An additional possibility for internal drillpipe isolation is the use of pump down float subs and darts.

6.2.2 Surface Valves

6.2.2.1 Surface valves include but are not limited to rig flow line isolation valves, MPD isolation valves, equalization line valves, fill-up line valves, and any valves that can potentially be exposed to SBP.

6.2.2.2 The surface valves shall be pressure rated to at least the maximum planned SBP.

6.3 Rotating Control Devices

6.3.1 . The RCD shall be deemed to be a component of the primary barrier envelope when applying surface back pressure in the well.

6.3.2 The RCD sealing assembly and elements are designed to accommodate certain tubular specifications (e.g., diameter, shape, smoothness). Therefore, the RCD sealing assembly and elements can be removed from the RCD housing prior to pulling or running tubulars through the RCD, which are outside the design specifications (considering the well will remain overbalanced).

6.3.3 The RCD limitations, such as stripping speed, pressure limits, rotating speed impact, shall be known by relevant personnel.

6.4 Trip Tanks

6.4.1 A trip tank cannot be used to monitor the well when applying surface back pressure. A flowmeter measuring the return flow should monitor the well fluid variation while stripping in and out of the wellbore.

6.4.2 A trip tank should be used to monitor the condition of the RCD, when the sealing assembly is installed.

6.4.3 When pulling the drill string out of the hole, with the well isolated and without the sealing assembly installed the primary use of the trip tank is to measure the amount of drilling fluid required to fill the hole to determine if drilling fluid volume matches pipe displacement.

6.4.5 When running the drill string into the hole, with the well isolated and without the sealing assembly installed, the primary use of the trip tank is to measure the amount of drilling fluid displaced from the well by the drill string to determine if drilling fluid volume matches pipe displacement.

6.4.6 The functioning of the trip tank should be verified prior to tripping operations.

6.5 Mud Buckets

6.5.1 When applying surface back pressure: The mud bucket drain line should be routed to the active tank. If any other drain path is used, provisions should be made to measure the fluids collected by that system.

6.5.2 When not applying surface back pressure and using the trip tank for wellbore monitoring: The mud bucket drain line should be routed to the trip tank. If any other drain path is used, provisions should be made to measure the fluids collected by that system.

6.5.3 The mud bucket drain line route should be verified prior to and monitored during the operation to accurately calculate proper displacement.

6.6 Alarms

6.6.1 The drilling contractor and operator shall determine alarm management for tripping operations. Operator and drilling contractor shall establish which parameters shall be configured for active alarm and the threshold levels to monitor the tripping operations. Parameters shall include, but are not limited to, the following:

a) high and low trip tank levels;

b) flow sensor alarms;

c) gas alarms;

d) active system volume.

6.6.2 The MPD service provider and operator shall determine additional alarm management for stripping operations. The MPD service provider and operator shall establish which parameters shall be configured for active alarm and the threshold levels to monitor the tripping operations. Parameters should include, but are not limited to, the following:

a) out of range SBP alarms;

b) delta flow alarms;

c) mud density;

d) stripping speed limits (e.g., Surge and Swab, RCD limitations).

e) RCD elements stripping pressure limits;

6.6.3 Audible and visual alarms shall be active and not muted during tripping operations.

6.6.4 Drilling contractors and MPD service providers shall have a defined process to manage unplanned changes to alarm parameters or alarm status(es) for the different states of the tripping operation or have an MOC process (or equivalent) that shall be followed.

6.6.5 Inadequate alarm management can lead to operational risks and have a detrimental effect on the driller's and MPD operator's effectiveness to manage well control.

6.6.6 The drilling contractor and MPD service provider should have an alarm management strategy in place that includes designs, processes, and procedures to manage nuisance alarms, alarm flooding, alarm shelving, and alarm suppression.

6.6.6.1 Excessive activation of alarms, especially nuisance or noncritical alarms, can lead to alarm flooding, which can have a detrimental effect on the driller's and MPD operator's ability to identify and effectively respond to an influx. Alarm flooding can accustom drillers and MPD operators to shelve or suppress alarms.

6.6.6.2 Alarm shelving should be controlled and limited to a predetermined period of time.

6.6.6.3 Alarm suppression shall be controlled by an MOC process (or equivalent).

7 Volume Management

7.1 General

7.1.1 During tripping operations with SBP, the well should always be full and fluid displacement should be measured and referenced to calculated values to ensure that the proper amount is being replaced into or displaced from the well.

7.1.2 If the hole fails to take the calculated amount of drilling fluid, tripping operations should be suspended and a safe course of action determined while observing the well.

7.1.3 Displacement and capacity volumes for tubulars used in the well shall be readily available for reference.

7.1.4 The minimum practical active pit volume should be used to perform tripping operations.

7.1.5 The volume of the fluid is affected by fluid expansivity due to heating (expansion) or cooling (contraction) of the well.

7.1.6 Minimize crane movement, fluid transfer/treatment, and other activities that might affect the proper well monitoring.

7.2 Drilling Fluid Considerations

7.2.1 Drilling fluid design and maintenance are integral parts of an effective primary well barrier.

7.2.2 Drilling fluid properties (particularly density) for fluid going into and coming out of the well should be monitored and maintained in accordance with the well plan during stripping operations, in particular if solids control equipment is in use.

7.2.3 Prior to starting tripping out, a bottoms-up circulation should be performed to condition the fluid in the well to facilitate the following:

a) to fill the annulus with fluid known to be free of gas/influx;

b) to remove cuttings;

c) to ensure the current fluid density of clean returns is sufficient with planned SBP to compensate for swab based on calculations for safe operations (see 8.4).

7.2.4 During tripping operations with SBP, the wellbore should be kept full of drilling fluid of an equivalent density that counters the effect of swabbing while supplementing with SBP.

7.2.5 Insufficient fluid density, or insufficient SBP can reduce wellbore pressure and result in events such as, but not limited to, swabbing in an influx, wellbore stability, hole collapse, and stuck pipe.

7.2.6 RCD stripping, static, and dynamic limits, and SBP operating limits should be considered when defining fluid density.

7.2.7 Prior to tripping operations the impact on equivalent mud weight due to applied SBP should be considered.

7.3 Fluid Transfers

7.3.1 Fluid transfers during tripping operations have implications when managing drilling fluid volumes. Influxes have the potential to go unrecognized if the fluid transfer process and volumes are mismanaged.

7.3.2 Water and/or diesel additions into the active system should be suspended during tripping operations.

7.3.3 If water and/or diesel additions into the active system cannot be suspended during tripping operations, then the volume of water and diesel additions should be periodically measured and monitored throughout the tripping operation.

7.3.4 Solids control equipment involving active tanks should be suspended during stripping operations.

7.3.5 When building additional volume for the active system, the additional volume should be isolated from the active system. After the additional volume is built, the entire amount should be accounted for in the PVT total.

7.3.6 When building additional volume of a different density than the active system, the additional volume should be isolated from the active system. When fluids of different densities are used in the tripping or mud rollover operation, extra precaution should be taken to monitor well returns such that each distinct fluid is properly transferred to its respective tank.

7.3.7 Fluid transfers between the active system and trip tank should be measured and monitored using a procedure designed to accurately track volumes, as it can be difficult to recognize kick indications if mismanaged.

7.3.8 The volume changes caused by fluid transfers should be recorded on the trip sheet.

7.4 Trip Sheets

7.4.1 The main controls of the well when applying surface back pressure below the RCD in wells with subsea BOP while tripping are the volume control, flow meter and trends from virtual trip tank (when available). The trip sheet is to be used in addition the mentioned controls.

7.4.2 Trip sheets shall be used to measure and identify downhole gains or losses by observing surface volume deviations from calculated values. Trip sheets are also used to account for tubular displacements and fluid transfers when tripping tubulars in and out of the well.

7.4.3 Trip sheet volume measurements should be evaluated by comparing the calculated and measured volumes for hole-fill or well returns for a specific number of stands when removed or added to the well.

NOTE 1 The calculated volume is a mathematical calculation of the tubular displacement based on the design specification.

NOTE 2 The measured volume is the actual observable displacement during tripping operations.

7.4.4 Wet displacement calculations are used when tubulars are pulled wet from the wellbore and the drilling fluid routed by the mud bucket does not drain into the same tank the wellbore is being filled from.

7.4.5 Dry displacement calculations are used when tubulars are pulled without fluids inside the tubular or when pulled wet from the wellbore and the drilling fluid routed by the mud bucket drains into the same tank the wellbore is being filled from.

7.4.6 Manual and digital trip sheets have their own inherent challenges that can affect their usability and accuracy; therefore, companies should take the appropriate measures to train their employees and periodically audit trip sheets for accuracy.

7.4.7 A trip sheet shall be completed when tripping in and out of an open wellbore with both theoretical and actual displacement/hole-fill volumes recorded and compared after every five stands of drill pipe, every three stands of heavy weight drill pipe, after every stand of drill collars.

NOTE In certain situations, such as pulling wet pipe, it may be appropriate to compare theoretical and actual volumes more frequently.

7.4.8 Completed trip sheets shall be accessible at the well site until the conclusion of the tripping operation.

7.4.9 The booster pump will be active during the tripping operation to maintain circulation through the MPD chokes and MPD flowmeter.

8 Well Control

8.1 General

8.1.1 Well control risks shall be identified during risk assessments and pre-job planning. These identified hazards and risks should be communicated in pre-job meetings, monitored, and mitigated as low as reasonably practicable.

8.1.2 Drilling contractors shall establish well control policies, procedures, and a competency management program to train personnel.

8.1.3 Drilling contractors shall train personnel on well control methods and shut-in procedures. Well control drills and MPD drills should be conducted periodically to evaluate crew response capabilities. See API RP 59 and API RP 92S for details regarding well control methods and drills.

8.1.4 The most common factors that cause the primary well barrier to fail are failure to keep the hole full, swabbing/surging, insufficient drilling fluid density, lost circulation, insufficient SBP, or a combination thereof.

8.1.5 When a kick is detected, the kick shall be suppressed and removed from the well in accordance with procedures prior to resuming stripping operations.

8.1.6 Prior to starting tripping operations,

a) A dynamic flowcheck shall be executed when using hydrostatically underbalanced fluid,

b) A static flowcheck may be used when using overbalanced fluid.

8.1.7 The driller has the ultimate authority and responsibility to shut in the well without asking permission and without any repercussion(s) when a kick is indicated or detected.

8.2 Well Barrier Elements

8.2.1 Conventional well barrier elements can be mechanical or nonmechanical and may include, but are not limited to, the following:

a) fluid column;
b) Subsea BOPs;
c) drill pipe safety valves;
d) packers;
e) plugs;
f) casing;
g) cement;
h) wellhead;
i) Drilling riser;
j) Rig Choke and Kill Lines;
k) Well control manifold.

8.2.2 Additional well barrier elements introduced during tripping with surface backpressure may include, but are not limited to the following:

a) rotating control devices;

b) MPD choke manifold;

c) MPD flow lines;

d) non-return valves;

e) MPD annular;

f) MPD riser joint;

g) MPD surface, upstream MPD chokes, and subsea lines;

h) Drop/pump down float valves;

i) Down hole isolation valve (casing valve);

j) Casing float valve (casing stripping operations).

8.2.3 The operator shall provide information from the well plan in accordance with API 97L.

8.2.4 The operator's well plan shall define well barriers and testing requirements for the different sections of the well construction design.

8.2.5 The operator's well plan should include a process to monitor and maintain the integrity of well barriers as their performance degrades over time and through service parameters such as, but not limited to, the following:

a) temperature;

b) pressure;

c) solids or particulates;

d) operating time;

e) fluid properties;

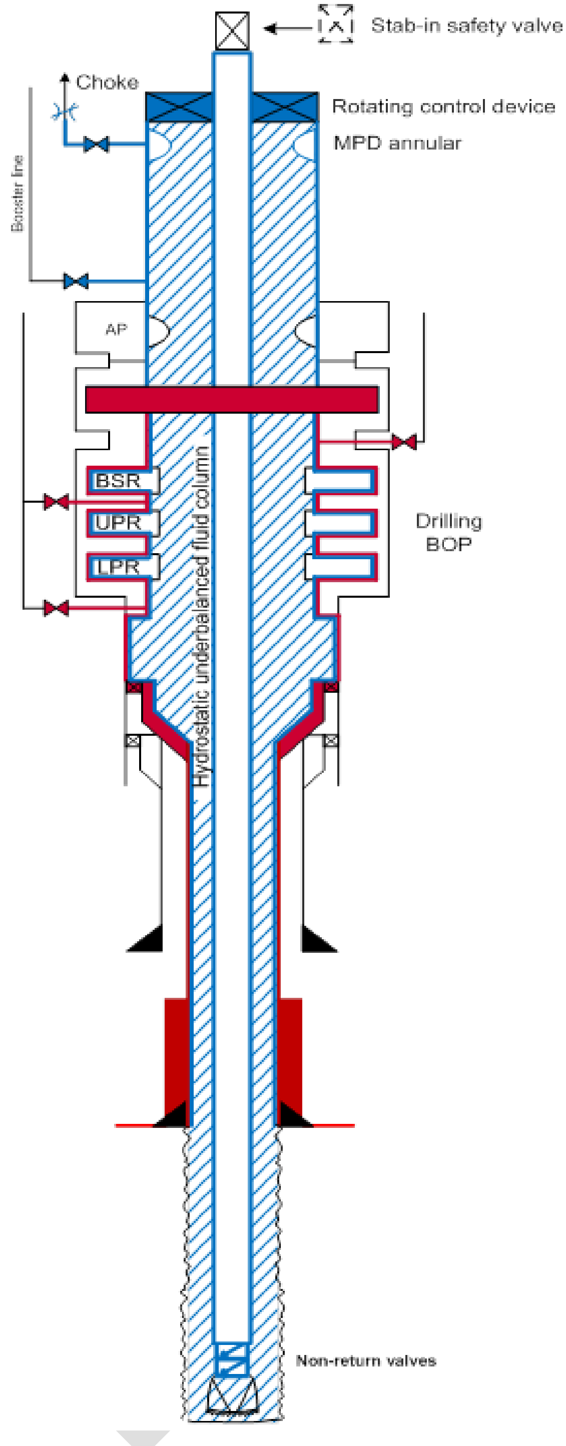
f) flow rate.

8.2.6 For tripping with surface backpressure in wells with hydrostatically overbalanced fluid with sufficient trip margin to compensate for swab, the primary well barrier is the hydrostatic mud column. For tripping with surface backpressure in wells without sufficient trip margin or utilizing hydrostatically underbalanced fluid, the primary well barrier additionally includes the RCD, and every equipment that retains and maintains the SBP applied to the well.

8.2.7 The secondary well barrier remains the same for MPD operations and for conventional drilling operations. None of the additional primary well barrier elements while tripping with SBP (including the RCD, and other MPD equipment) constitute elements of the secondary well barrier envelope.

8.2.8 If the primary well barrier integrity falls below the design tolerance, the operator shall ensure that no other activities take place, other than those intended to restore the primary well barrier. If the primary well barrier integrity cannot be re-established, the well should be secured with the secondary well barrier envelope. After the first barrier is reestablished, it should be evaluated if a MOC is necessary prior to continue operations.

8.2.9 Both primary and secondary well barriers shall be identified for MPD tripping. Well barrier schematics should be made to identify well barrier elements for each phase in the MPD tripping when there are changes in the barrier. Figure 1 shows an example of well barrier elements while tripping in MPD mode.



Well Barrier Elements	Comments
Primary Well Barrier	
Static underbalanced fluid column	
Casing*	
Wellhead*	
Marine riser	Below telescopic joint
Drilling BOP*	
Rotating control device	
Drilling NRVs	Minimum two
Drill string or completion string	
MPD annular	
MPD choke system	Including control system
Secondary Well Barrier	
In situ formation	
Casing cement	
Casing [a]	
Wellhead [a]	
Drilling BOP [a]	
[a] Common well barrier element.	

Figure 1 – Well Barrier Schematic Example

8.3 Kick Indicators

8.3.1 Warning signs of a kick during tripping operations shall be investigated. These warning signs can include, but are not limited to, the following:

a) pit gain;

b) increased return flow;

c) changes in fluid returns, e.g., temperature and density;

d) pressure build up after the pumps are stopped (when trapping pressure);

e) increase in choke position to maintain the same SBP;

f) increasing SBP trend if on constant choke position;

g) changes in flowback signature in connections compared to previous connections;

h) Virtual trip tank gain.

8.3.2 Kick indication and detection can be complicated by the following:

a) high-angle or horizontal wellbores;

b) slowly occurring gas migration and expansion;

c) simultaneous fluid loss and influx in different parts of the wellbore;

d) a net fluid loss on a trip sheet concealing an influx;

e) Dissolved gas in non-water-based mud;

f) MPD choke washout/plugging;

g) sensor/control system malfunctions;

h) improper detection/analysis parameters;

i) leak on well isolation equipment (Subsea BOP or Downhole Isolation Valve) while holding pressure in the well; Balooning/Breathing formation.

j) Low intensity, low flow rate influxes.

8.3.3 Tight operational windows might result in losses and gains in the well, if there is an indication of simultaneous fluid loss and influx taking place, appropriate well control actions should be taken.

8.3.4 Dynamic flow checks and conventional flow checks may not show a flow increase when simultaneous fluid loss and influx is occurring.

8.3.5 Simultaneous fluid loss and influx is particularly a concern when non-water-based drilling fluid is being used, as dissolved gas will typically not come out of solution before the gas gets closer to the surface.

8.4 Trip Margins

8.4.1 The primary well barrier might be lost due to swabbing effects. A swab margin, by additional hydrostatic and or surface back pressure shall be considered.

Pumping out of the hole to reduce the swabbing effects should be considered as an alternative method.

8.4.2 The maximum tripping speed to maintain the pressure within the operational window shall be calculated for different hole sections considering surge and swab effects.

8.4.3 Additional overbalance margin may be necessary due to thermal effects on fluids in high pressure/high temperature wells where temperature effects can decrease the fluid density.

8.4.4 When tripping in the surge effect should be considered as it can take the well pressure outside the operational window. Proper surface back pressure schedule should be planned prior to the operation.

8.4.5 Puling out of the hole can be done wet or dry. A dry trip might be a cleaner operation, but complicates the proper control of the pressure profile in the well, considering the new fluid in the system and its dynamics through the annular.

8.4.6 A sufficient trip margin can be confirmed using a bottoms-up circulation after a pulling a few stands, then returning to bottom. The bottoms-up serves as an opportunity to confirm that the integrity of the primary barrier was maintained and was not affected by the swabbing effect.

8.4.7 If PWD is available downhole data such as minimum and maximum ESD can provide the feedback of proper swab and surge margins.

8.5 Dynamic Flow Checks

8.5.1 When using surface back pressure and under balance fluid a static flow check is not possible. A dynamic flow check is required in these situations. The dynamic flow check shall be performed to determine if the well is static and no fluid is being lost to or gained from the formation. Dynamic Flow checks for tripping out of a hole shall be performed, at a minimum:

a) prior to starting tripping operations;

b) at the lowest casing seat;

c) before pulling BHA across the BOP.

Note: Once the well is filled with hydrostatic overbalanced fluid, it is possible to do conventional flow checks.

8.5.2 Optional dynamic flow checks may be beneficial to confirm that the primary well barrier is still effective. These include, but are not limited to, the following:

a) between three and five stands after starting tripping operations, to confirm swab margin;

b) before pulling into the curve from a horizontal section;

c) before removing the RCD bearing/sealing element;

d) before resuming operations after opening the well;

e) when the discrepancy between the calculated and measured volumes in the trip sheet is above a predetermined threshold.

8.5.3 The drill string should not be reciprocated when conducting dynamic flow checks.

8.5.4 In the process of doing a dynamic flow check, if it is suspected that the well is gaining/losing and ballooning or wellbore breathing, the well parameters should be assessed, confirmed, and monitored to ensure that the primary well barrier is sufficient before starting to trip pipe.

8.5.5 Contractors and operators should determine and agree on when additional dynamic flow checks are necessary for their operations and what thresholds trigger additional dynamic flow checks and well control responses.

8.5.6 Prior to beginning tripping operations, it is recommended that one or more bottoms-up circulation are completed. This can help remove gas from the wellbore and condition the drilling fluid.

8.5.7 Dynamic Flow checks shall be documented on the trip sheet.

8.5.8 Details regarding the dynamic flow check shall be recorded and include, but are not limited to, time, depth, duration and outcome.

8.5.9 In case of measured gains, if ballooning is not confirmed, follow the operational matrix.

8.5.10 Dynamic flow checks should be conducted for a predetermined length of time to confirm the well is gaining or losing. If the well initially appears to be gaining or losing, a dynamic flow check is often continued for a prescribed time to help identify subtle or delayed flow behaviors.

9 Tripping Operational Guidelines

9.1 General

9.1.1 Safety meetings should be conducted with appropriate personnel prior to starting tripping operations and repeated as needed throughout the operation (see Section 5).

9.1.2 Safety meetings should cover risk assessment, equipment procedures and parameters, equipment alignment and verification, job steps, flow checks, drill string, BHA, type of fill methods to be employed, etc.

9.1.3 Prior to tripping out of the hole:

9.1.3.1 The well control worksheet (kill sheet) shall be verified or updated, including, but not limited to, drill string information, drilling fluid density, slow circulating rate, and hole depth. See API 59 for examples of well control worksheets.

9.1.3.2 Ensure that the tripping parameters are within operational matrix or the influx management envelope.

9.1.4 Current BOP and choke manifold drawings, detailing space-out, pressure ratings, and ram closing pressures for different tubulars used shall be maintained and available in the driller's cabin (see API 53 for more information).

9.1.5 Contractors shall have a documented and accessible procedure to verify the presence of trapped pressure in the wellbore prior to opening the BOP.

9.1.6 If shutting in the BOPs during trips, the pressure shall be monitored continuously, and the well should be equalized prior to opening the blind rams.

9.2 Training

9.2.1 Personnel should be educated and trained on, but not limited to, the following:

a) MPD and well control system components, including installation, maintenance, and operation;

b) Response procedures to potential well control situations;

c) Tripping procedures, including the equipment used for tripping operations;

d) Trip sheets and hole-fill methods and monitoring;

e) Emergency Response Plans, including emergency action procedures;

f) MPD and Well control training to anyone directly involved in the operation (assistant driller, driller, rig manager, company representative, MPD operator, etc.)

9.2.2 Training can be a combination of onshore (classroom, simulator, workshop) and offshore (drill, on the job training) training.

9.2.3 Training should be modified or updated as needed to address unique or rig-specific conditions or operations.

9.2.4 Training should be provided when introducing new technologies, systems, or methods.

9.3 Tripping Operations

9.3.1 Operational parameters and alarms should be established and documented prior to tripping operations and adjusted as needed (e.g. hook load, overpull, torque, block height, flow, speed, gain, SBP, etc.).

9.3.2 The circulating system (MPD chokes, Trip Tank, correct flow path, valves, PRVs…) shall be verified as properly aligned prior to starting tripping operations to enable accurate trip sheet monitoring.

9.3.3 Abnormal flow, after the process of shutting down the pumps is completed, can be caused by several factors including, but not limited to, the following:

a) an influx of formation fluid;

b) thermal expansion of the drilling fluid;

c) the apparent nonvolumetric wellbore behavior (ballooning or well breathing);

d) return lines draining;

e) Compressibility;

f) U-tube effect (different weight fluids in the well/string, NRV failure).

g) Unassociated surface volume management (fluid transfer, pit management, shakers cleaning, cuttings dryer return).

9.3.4 The continuous fill method is the most used method for trip out. When applicable, it may be considered as choice for human factors considerations.

9.3.5 When circulating through the MPD SBP system the well is going to be continuously filled. The delta flow, negative for trip out, and positive for trip in, in balance situation should equal the calculated string displacement. If the circulating rate is held constant, the flow from the annulus (or over the top of the annulus if using the continuous-fill method) should be constant except for changes caused by pipe volumes being removed or added to the well. If the annulus flow increases without being displaced by pipe being added, the additional flow could be caused by the influx of formation fluid(s) into the wellbore or entrained gas expansion.

9.3.6 For changes from the approved plan that impact the fill method, a risk assessment (MOC or equivalent) shall be performed prior to using an alternative hole-fill method.

9.3.7 Monitoring fluid volumes and tripping speeds are essential to identify and mitigate the risk associated with surging and swabbing.

9.3.8 When running tubulars into the wellbore, mitigation actions shall be taken when drilling fluid volume measured at surface is abnormally less than or greater than the calculated string volume displacement.

9.3.9 Dynamic variation in flow rates and volumes can occur when running or pulling tubulars in and out of the wellbore. Volume and flow variations during tripping operations should be fingerprinted, and the appropriate boundaries should be established for the alarms.

9.3.10 Contributing factors to drilling fluid losses include, but are not limited to, the following:

a) excessive drilling fluid density;

b) excessive annular circulating pressure;

c) packing-off in the annulus;

d) pressure surges related to running pipe or tools;

e) breaking circulation;

f) faults or naturally fractured formations;

g) weak formation or highly permeable formations;

h) excessive SBP.

9.3.11 Supervisors shall assess whether to continue to trip out or return the string to bottom. When a trip sheet volumetric or flow discrepancy triggers a flow check or dynamic flow check, a negative (dynamic) flow check may not confirm that formation fluids have not entered the wellbore.

9.3.12 Swabbing the well beyond the trip margin/safety factor can result in an influx of formation fluid into the wellbore. Hole-fill volumes that are less than expected or higher than expected return flow rates can be an indication of swabbing an influx.

NOTE See API 59 for response actions when swabbing is detected.

9.3.13 The initial tank volume shall be recorded prior to starting tripping operations to enable accurate trip sheet monitoring. Trip sheets shall be completed and monitored in accordance with 7.4.

9.3.14 If the primary well barrier (the drilling fluid hydrostatic column, friction losses and SBP) falls below the design tolerance, the operator shall ensure that no other activities take place, other than those intended to restore the primary well barrier. If the primary well barrier cannot be re-established, the well shall be secured. Prior to continuing tripping operations, an assessment shall be done according to company policies and procedures.

Bibliography

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