Managed Pressure Drilling Supplement

Beyond

WCS

WELL CONTROL SCHOOL

Rev. 0, Mar-24

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

ATR Above Tension Ring

BHP Bottom-Hole Pressure

BOP Blow Out Preventer

BTR Below Tension Ring

DGD Dual-Gradient Drilling

DP Dynamic Positioned

ECD Equivalent Circulating Density

EMW Weight Equivalent Mud Weight

HSE Health, Safety and Environmental

IME Influx Management Envelope

LMRP Lower Marine Riser Package

LWD Logging While Drilling

MPD Managed Pressure Drilling

MWD Measurement While Drilling

NPT Non-Productive Time

PLC Programmable Logic Controlled

PMCD Pressurized Mud Cap Drilling

PWD Pressure While Drilling

RFC Returns Flow Control

RCD Rotating Control Device

PRV Pressure Relief Valve

RWP Rated Working Pressure

SBP Surface Back Pressure

SWL Safe Working Load

SWP Safe Working Pressure

UBD Under Balanced Drilling

WBE Well Barrier Element

MPD versus UBD

- Underbalanced drilling and Managed Pressure drilling are NOT the same.
- In underbalanced drilling (UBD), the hydrostatic head of the drilling fluid is intentionally designed to be lower than the pressure of the formations that are being drilled. The hydrostatic head of the fluid may naturally be less than the formation pressure, or it can be induced by adding different substances to the liquid phase of the drilling fluid, such as: Natural gas, Nitrogen, and Air. Whether the underbalanced status is induced or natural, the result may be an influx of formation fluids that must be circulated from the well and controlled at surface. Permeability is a large contributing factor to if underbalanced drilling is possible through the chosen formation.
- The International Association of Drilling Contractors (IADC) defines Managed Pressure Drilling as "*An adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the down-hole pressure environmental limits and to manage the annular hydraulic pressure profile accordingly*."
- MPD uses equipment systems, and techniques to provide drilling operations with more tools to manage the pressure profile throughout the well.
- The most popular MPD technique is the **Surface Back Pressure (SBP)** technique. This technique uses a **Rotating Control Device (RCD)** to seal around the drill pipe, enabling drillers to apply positive pressure on surface (annular side) via a dedicated MPD choke valve.

Conventional Drilling

- System open to the atmosphere.
- Unable to change pressure profile instantaneously without changing the flow rate.
- Susceptible to gas in the system: Drilling operations need to be stopped to deal with gas.
- Heavy mud densities.

Managed Pressure Drilling

- Closed system creates a safer work environment (e.g., Rig floor personnel isolated from well fluids).
- Pressure profile can be changed in seconds to adapt to actual wellbore conditions.
- Gas can be safely diverted to the MPD system and separated away from rig.
- Allows for more flexibility in terms of drilling fluids to be used.

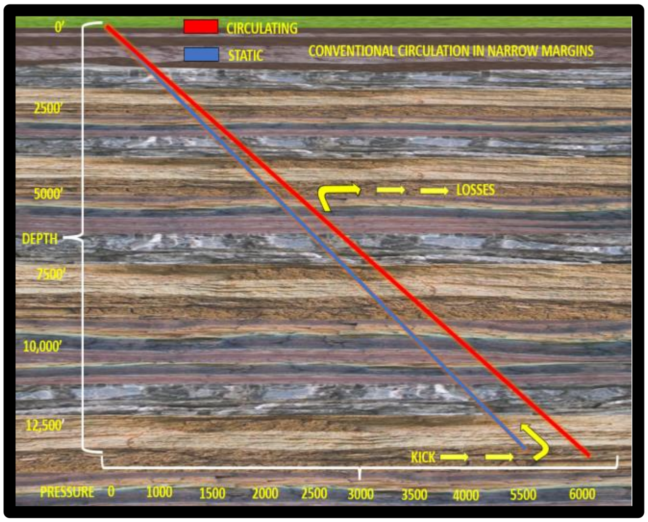

Image: MPD-22.9

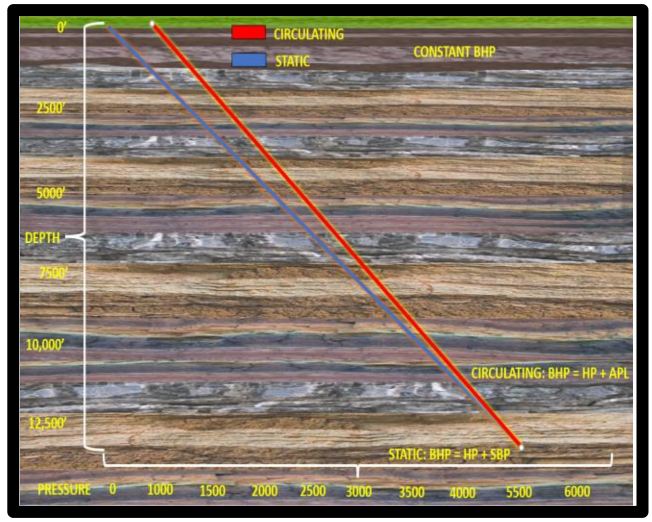

Image: MPD-22.10

Variations of managed pressure drilling:

There are four key variations of MPD, each intended to address specific challenges to conventional drilling programs.

1. **Constant Bottom Hole Pressure (CBHP):** Used when drilling in narrow, shifting and/or relatively unknown mud **Equivalent Weight Mud Weight (EMW)** windows that have potential kick/loss scenarios such as illustrated in **Figure MPD-22.9** CBHP enables drilling with a lighter mud that avoids losses when circulating and applies surface backpressure CBP) when not circulating to prevent well flow, as illustrated in **Figure MPD-22.10.**

2. **Pressurized Mud Cap Drilling (PMCD):** Used when drilling in severe to total loss circulation zones with a usually clear solids free sacrificial fluid and no returns to surface, as illustrated in **Figure MPD-22.11.**

3. **Mud Cap drilling** (MCD): Used where total or near-total loss of circulation occurs, and drilling is continued by maintaining a “height” or "cap" of mud in the annulus, while pumping drilling fluid down the drill string with no returns to surface. (Note: MCD may not necessarily be MPD)

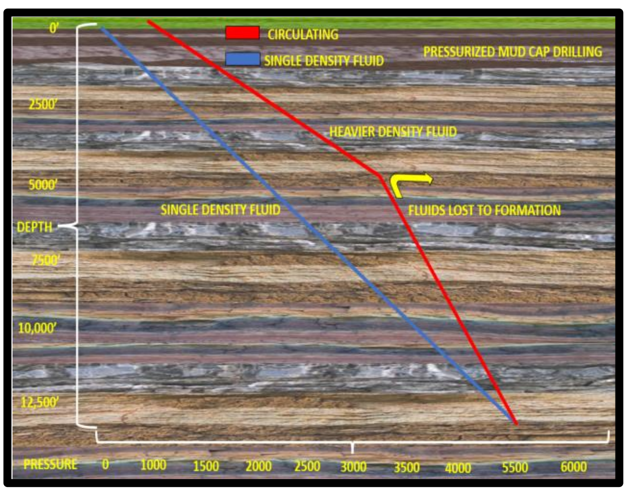

Image: MPD-22.11

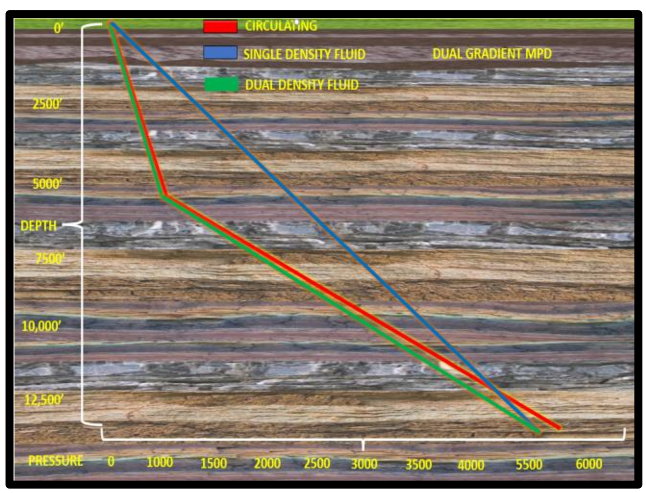

Image: MPD-22.12

4. **Returns Flow Control (RFC) for Health, Safety and Environmental** (**HSE) (RFC-HSE):** Used when drilling with a closed-loop circulating-fluids system for HSE reasons only. The key components of a closed-loop system are an RCD, drill string non-return valves (floats) and a usually dedicated choke. Not all systems require a choke.
   If a **programmable logic controlled (PLC)** automatic choke system enables early kick-loss detection, dentification of ballooning phenomenon in real-time, and the ability to conduct frequent dynamic **formation integrity tests (FITs)** and **leak-off tests (LOTs)** without drilling interruption. Dynamic tests are not possible if a choke is not part of the system.

5. **Dual-Gradient Drilling (DGD):** Used when two or more depth versus pressure gradients in the annulus, as illustrated in **Figure MPD-22.12** For CBHP, some of the same dedicated equipment required for UBD is used. For example: float valves in most cases, RCD, and a dedicated drilling choke manifold cleanly delineated from the well control system. Dual gradients in the annulus may be achieved by using gas, lighter mud or by using subsea mud-lift pumps. Requires careful pre-planning, hydraulic flow modeling, hazard assessment processes, crew training and interactive drilling program implementation for safe and effective application. Pre-planning and well control contingency plans must be well defined and understood by everyone involved.

Equipment overview:

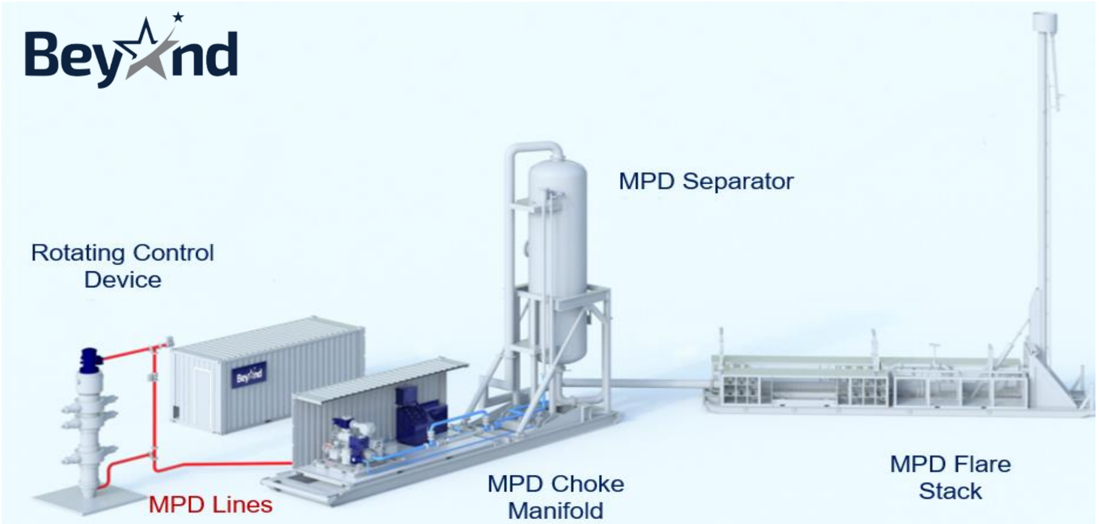

Image: MPD-22.1

- **Rotating Control Device (RCD):** Allows a seal around the drill pipe, enabling the application of annular Surface Back Pressure **(SBP)**. RCDs cannot be considered well control equipment.
- **MPD Lines:** Pipelines that divert the flow from the well to the MPD equipment.
- **MPD Choke Manifold:** Assembly of pipes, fittings, and valves, including the choke valves, responsible for managing the annular Surface Back Pressure (SBP) value. MPD control systems and flow meters are also part of this assembly.
- **MPD Separator and Flare Stack:** These components allow handling of incidental influxes of gas if they occur (not used in all MPD applications).

Components of Bottom Hole Pressure (BHP)

Beyond	Conventional Applications	MPD Applications
Static Periods	BHP = Hydrostatic Pressure	BHP = Hydrostatic Pressure + **Surface Back Pressure**
Dynamic Periods	BHP = Hydrostatic Pressure + Circulating Pressure	BHP = Hydrostatic Pressure + Circulating Pressure + **Surface Back Pressure**

Image: MPD-22.2

Primary Well Control

- Primary well control dictates that BHP must be greater than the pore pressure in the hole.
- For conventional applications, the hydrostatic pressure is the only component of BHP during pumps-off (static) periods, therefore **mud weight (MW)** must be greater than **pore pressure (PP)** for the **Bottom Hole Pressure (BHP)** to be greater than pore pressure.
- In MPD applications, an additional component, Surface Back Pressure (SBP), provides additional pressure to the BHP. In this case, MW can be less than PP (hydrostatically underbalanced condition), but the sum of MW + Surface Back Pressure must be greater than the pore pressure to maintain the overbalanced condition during static periods.

The Influx Management Envelope (IME) concept defines the operational envelope in case of incidental influxes during MPD operations. It is based on kick-tolerance concepts, in which a relationship between volume and intensity of the influx is established and plotted as a graph. (Note: The Well Operations Matrix can also be used instead of the IME)

IME Implementation

From the IME concept, parameter combinations (influx volumes and SBP) not expected to exceed the established pressure limits are considered to be safe to circulate through the MPD equipment.

Preliminary Conditions. *Ability to Shut In*. It must be possible to stop circulation and the well at any time during the influx-removal process without exceeding downhole or surface pressure limits.

Adjusted Post-Influx SBP. This is calculated to provide better insight about the intensity of the influx once the event has been detected and the inflow stopped by the addition of SBP.

SBP Safety Margin. The project team decided to establish a safety margin for the SBP after influx-cessation confirmation (i.e., flow out is equal to or less than flow in) to avoid secondary influxes caused by bottom hole-pressure variations incidental to the MPD operation.

Assessment Depth. The IMEs were prepared for total depth (TD) of each section and were considered as the worst-case scenario for an influx.

Mud-Pump Rates. The mud-circulating rates planned for all three-hole sections exceed the liquid-flow-rate limit of the mud/gas separator in the presence of gas. Therefore, the project team established that, in the event of dynamic circulation of an influx, the flow rate would need to be reduced when the front of the influx reaches approximately 1000 m from the surface.

Minimum Influx-Detection Limit. For the graphical representation of IMEs in image 22.3, a minimum influx-detection limit of 2 bbl. has been arbitrarily selected, defining the limit between normal MPD operations (Green region) and contingency influx response (Yellow, Orange, or Red region). However, for this project, any detected influx would trigger influx response, placing operations automatically outside of the Green region, even if the detected volume is less than 2 bbl. Normal MPD operations can be conducted only in the absence of influx in the wellbore.

Anchor-Point (AP) Location. This project has planned to maintain the AP at the bit location for all three-hole sections. Different AP locations would have an effect on the process for calculating the section maximum and, thus, the maximum allowable influx volume.

Beyond

Managed Pressure Drilling Operations Matrix

		RCD Model	Titan with Ares 1578 Bearing Assembly				Well Name	Well #1 (Template)		
Influx Volume (bbl)		Surface Annular Pressure Dynamic Conditions (pipe moving)					Surface Annular Pressure Static Conditions (pipe static)			
		Max RPM	Less than	Min	Max	Greater than	Less than	Min	Max	Greater than
		100	750	750	1,000	1,000	1,000	1,000	1,500	1,500
		120	500	500	750	750				
		150	500	500	500	500				
Less than	5.0		Manageable. Continue drilling	Continue drilling; adjust system to decrease WHP		Secure well. Evaluate next planned action	Manageable. Continue operation	Continue operation; adjust system to decrease WHP		Secure well. Evaluate next planned action
Min / Max	5.0 / 10.0		Continue drilling; adjust system to increase BHP	Continue drilling; adjust system to decrease WHP and increase BHP		Secure well. Evaluate next planned action	Continue operation; adjust system to increase BHP	Continue operation; adjust system to decrease WHP and increase BHP		Secure well. Evaluate next planned action
Min / Max	10.0 / 25.0		Cease drilling; adjust system to increase BHP	Secure well. Evaluate next planned action		Secure well. Evaluate next planned action	Stop operation; Adjust system to increase BHP	Secure well. Evaluate next planned action		Secure well. Evaluate next planned action
Greater than	25.0		Secure well. Evaluate next planned action	Secure well. Evaluate next planned action		Secure well. Evaluate next planned action	Secure well. Evaluate next planned action	Secure well. Evaluate next planned action		Secure well. Evaluate next planned action

Notes:
- Max RPM refers to surface RPM
- Well cannot be secured using MPD equipment

Image: MPD-22.3

A resulting combination of regions within the volume-and-intensity graph depicts the conditions in which an influx can be removed safely from the wellbore by use of the elements of the primary wellbore barrier; otherwise, the secondary wellbore barrier should be engaged and the well shut in conventionally. The regions are color coded for ease of identification during the process of managing an influx. Three regions have been described:

- The Green region identifies normal MPD operations, where drilling and other operations continue as planned. No influx is detected in the wellbore, and surface pressures are within planned parameters.
- The Yellow region defines the operational region where an influx has been detected in the wellbore and the influx can be circulated safely to surface within the boundaries of the primary wellbore barrier.
- The Red region defines the conditions in which it is deemed that some limits of the primary barrier would be exceeded during the process, indicating that the well should be secured with a secondary-barrier envelope.

The Orange Region. In this work, an additional (optional) Orange region is added as a subset of the Yellow region**.** In the Orange region, an influx can be removed safely within the primary wellbore barrier, but one or more parameters will need to be modified to avoid exceeding some limits in the process.

*The matrix information and explanations was derived from an article, written by *JPT* Technology Editor Chris Carpenter, and contains highlights of paper SPE 185289, "Case Study: First Experience of Developing an Influx-Management Envelope for a Deepwater MPD Operation," by **O.R. Gabaldon, P.R. Brand, M.S. Culen, I.U. Haq, R.A. Gonzalez-Luis, T. Pinheiro Da Silva, G. Puerto,** and **W. Bacon,** Blade Energy Partners, prepared for the 2017 SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition, Rio de Janeiro, 28–29 March.

Depending on the MPD system set-up, a **Coriolis Flow meter** can be installed to measure the flow in and/or flow out from the well. The delta value between the two flow measurements can be used to indicate an influx (flow out > flow in) or losses (flow out < flow in).

During steady-state periods (no changes in drilling parameters), the choke position can also be used as an indication of an influx while circulating. Theoretically, the choke position must remain constant should the rest of the parameters remain constant. A choke valve that needs to keep opening in order to maintain a fixed pressure value can be an indication of an influx.

During pipe connections, when surface back pressure is applied, such pressure is expected to remain constant throughout the connection. If the surface pressure starts to build up, it is an indication of a potential influx.

API RP 92 M States:

2.1.10 primary well barrier; the first well barrier that prevents flow from a source.

2.1.11 primary well barrier; The individual equipment items and components that form the primary well barrier.

2.1.12 RCD sealing element; Sealing element between the rotating control device and the drill string.

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

API RP 92 S states:

9.2.1.2 MPD introduces additional well barrier elements; these may include, but are not limited to, the following:

a) RCD

b) riser isolation tool (annular)

c) termination joint

d) flow return spool

e) flow valves

f) flexible flow lines

g) MPD choke manifold

h) surface valves (e.g. check valve after BPP)

i) drill string w/NRVs

9.2.1.3 MPD well barrier elements shall be rated to withstand the maximum anticipated pressure expected for planned operations and a safety factor should be applied.

9.2.1.4 Upon initial rig-up and installation of MPD well barrier elements, the integrity and functionality shall be verified by means of a pressure test to at least the maximum anticipated pressure and a function test of those well barrier elements that require activation. An example of when to perform this test is prior to drilling out the casing shoe prior to commencing MPD operations.

9.2.1.5 Due to operational restrictions, it may be feasible only to test replacement sealing elements to the maximum available SBP as opposed to maximum anticipated pressure.

9.2.2 Well Barrier Schematics Both primary and secondary well barrier shall be identified for all MPD operations. Well barrier schematics should be made to identify well barrier elements for each phase in the MPD operation (drilling and tripping the drilling BHA, running a completion, etc.) when there are changes in the barrier.

API Spec 16 RCD States:

1.2.1 Equipment

a) active, passive, and hybrid rotating control devices

b) RCD bearing assemblies including metallic and non-metallic parts

c) RCD packer units (active and passive types)

d) RCD housing clamps or locking mechanisms

6.2.4.3.4 Above Tension Ring (ATR) MPD Riser Components

Above tension ring MPD riser components consist of the following.

a) Riser connector to mate with outer barrel or riser tension crossover.

b) Return flow outlets (e.g. flow spool) with hydraulically controlled MPD dual isolation valves, providing means to route well return fluids through suitable flexible hose(s) to the rig and provide a way to inject fluid into the top of the riser.

c) A means for installing a suitably rated **Pressure Relief Valve (PRV)** to enable overpressure protection for the riser.

d) MPD annular (or means of enabling an alternative barrier, such as the **Lower Marine Riser Package (LMRP)** annular); this provides a means of maintaining back-pressure while changing out the RCD seal element in the event of leakage.

e) For dynamically positioned vessels, ability of the ATR MPD system to accommodate vessel heading change.

f) RCD housing plus suitably rated flexible hose to enable bleeding off or equalizing pressure/checking for gas below the RCD seal element before changing it out above a closed MPD annular.

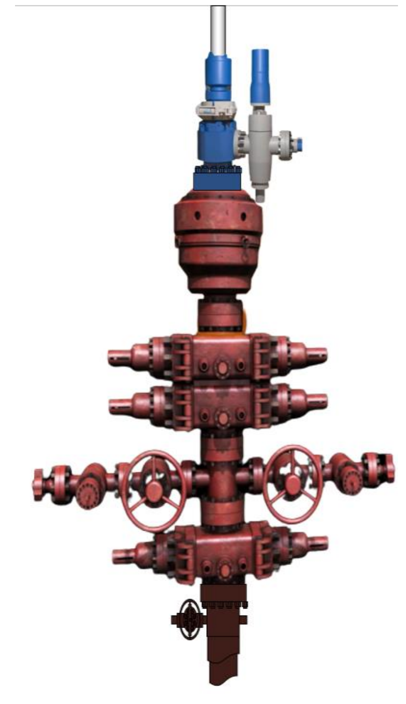

Image: MPD-22.4

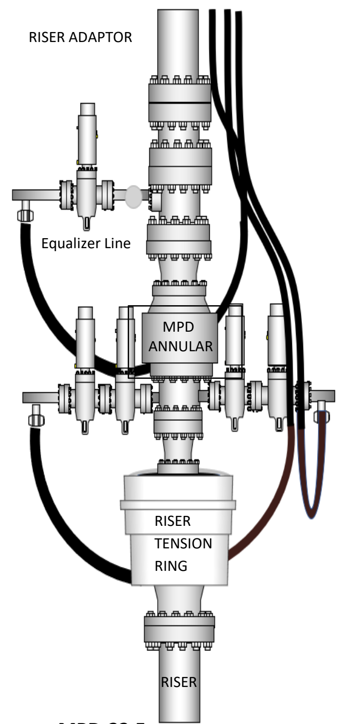

Image: MPD-22.5

Image: MPD-22.6

6.2.5 Riser Analysis and Riser Preparation

6.2.5.1 The riser inspection and operating records should be reviewed and, if deemed necessary, riser inspections should be carried out in accordance with original equipment manufacturer/drilling contractor/operator procedures.

6.2.5.2 If wear is detected in the riser main tube, eliminate it if possible; if unable to do so, the resultant riser wall thickness shall be used in riser analysis calculations.

6.2.5.3 Sealing areas should be in serviceable condition; make repairs as required.

6.2.5.4 Riser equipment that will be located above the RCD housing should be drifted.

6.2.5.5 A riser analysis shall be performed in accordance with **API Spec 16Q** (pg. 12) and, if applicable, **API RP 2RD** for the planned well location considering the following:

a) Planned maximum mud weight to be used

b) Desired maximum MPD surface back-pressure if switching between surface back-pressure MPD and PMCD

c) Location metocean data

d) Including additional weight and location of additional riser components (ATR or BTR)

e) Surface conductor configuration

f) Rig positioning (moored or DP)

g) Global riser stress and fatigue analysis (see **API spec 16Q**) for combined load case of maximum mud weight, environmental loads, applied back-pressure, and pressure cycling

h) Drag effect from waves/currents on additional (MPD/**Pressurized Mud Cap Drilling PMCD**) riser components in splash zone.

6.2.5.6 The riser analysis report should supply the following information for use by the rig operating crew:

a) API riser buckling stability criteria calculations in accordance with **API Spec 16Q**

b) Riser operability and drilling performance

c) Wellhead and conductor bending loads

d) Station-keeping watch circle limit guidance based on riser mechanical limitations.

6.2.5.7 In the case of an ATR solution being used, a riser recoil analysis should be performed considering:

a) Reduced available telescopic joint stroke

b) Reduced distance to dissipate recoil energy after unlatching

c) Additional weights of MPD/PMCD riser components above the tension ring

d) Potential impact loads on MPD riser components after closure of MPD telescopic joint

e) Effect of riser pressure

f) The riser recoil analysis should identify any changes required to any rig riser recoil software or hardware to safely manage the revised riser arrangement

6.2.5.8 The risk of risers and BOPs being affected by external differential (collapse) pressures should be evaluated. The evaluation should include review of the riser, BOP, and wellhead connector limitations, review of the lower flex joint external pressure limitations.

6.2.5.9 Consider the effect of emergency disconnect on the wellbore pressure (e.g. riser margin).

API Spec 16Q: Riser analysis

5.2 Riser Analysis Considerations

5.2.1 Data required to perform a riser analysis include information about the drilling riser, the drilling vessel equipment, motion, characteristics, offset planned drilling fluid weights, the meta ocean criteria to be considered, the wellbore design, any unique considerations due to the planned well operations, and the subsea wellhead entry.

5 2.2 Special vessel station keeping considerations: The vessels station keeping ability should be determined and used in conjunction with the riser analysis to access and assess flex ball joint angles tension or stroke telescoping joint stroke, riser stresses, casing loads and wellhead loads for a moored operation. It may be useful to use mooring and riser analysis together to define operating limits. In some cases, mooring lines may have been actively adjusted in response to long term variations in environmental conditions such as current and or wind. For a DP operation watch circles can be adjusted based on the response of the riser system at various vessel offsets.

5.2.3 Riser induced load considerations: The riser induces shear bending torsion and tension loads into the BOP stack and wellhead. These loads and moments should be evaluated to ensure that they and their resulting maximum stresses are within design allowable’s. Furthermore, selection of casing size and strength as well as the wellhead and any other related components at the mudline region may be contingent upon these loads and moments.

5. 2.4 Internal fluid densities: Riser tension setting should be determined for fluid densities (e.g., mud weight) ranging from seawater up to the maximum anticipated density in the main tube and each external line. Allowable fluid densities may be influenced by applied internal pressures for well controlled situations or during **MPD.**

5.2.5 Temperature and pressure: The riser should only be operated within its design limits which are inclusive of temperature and pressure ratings. Planning for well operation consideration should be given to expected well temperatures and pressures particularly on high pressure high temperature wells (HPHT) refer to API RP 16 C and API 16 F for further information on this aspect of razor design. Seek manufacturers guidance, if necessary, for questions concerning the suitability of a particular riser system including materials seals, etc., for expected temperatures and pressures.

Summary of MPD:

- With the exception of Dual Gradient Drilling, MPD and UBD methods use an RCD to divert formation and drilling fluid flow to a separator.
- API RP 92M requires 2 barriers between the well and the surface, The MPD system and the drilling fluids are referred to as primary barriers and the BOP being the secondary.
- The RCD helps create a closed system with a drilling choke manifold, an annulus pressure pump and sometimes a Coriolis meter to control down hole pressure.
- MPD keeps a specific point in the well constant, referred to as the "anchor point."
- When the rig pumps are shut down; back pressure is applied to the EMW with the pumps off as the ECD with the pumps on.
- Pressure while Drilling tools (PWDs) can be used to fingerprint in UBD/MPD situations.
- Well Control chokes should not be used for MPD drilling; they are needed in case of unforeseen circumstances and must be operational in case of such an event.
- It is recommended that the MPD path and well control paths are ***separate*** from one another.
- MPD equipment is not secondary well control equipment.
- ***It is imperative the MPD equipment is rigged up downstream of the stack, so the BOP is not downgraded to the Rated Working Pressure (RWP) of the MPD equipment.***

Value of using MPD techniques:

1. **May avoid pressure related events like stuck pipe, hole collapse, connection gas, lost circulation**
2. **Ability to accurately circulate out small influxes without stopping drilling operations**
3. **Mitigates pressure fluctuations and formation fatigue, improving wellbore stability**
4. **Allows for continuous control of downhole pressures, providing instant downhole pressure changes**
5. **Allows for higher ROP**
6. **Ability to perform reservoir characterization while drilling**
7. **Mitigates formation damage during drilling, increasing production**

Sources: The SMEs at Blade Energy services, API 92 M, API 92 S, API 92 P, API 16 RCD, "Managed pressure drilling erasing the lines" Shell, The Hague, Talisman Energy 2011, IADC MP manual 12th edition, IADC Lexicon.

IRP 22 (Canada) is a valuable and free to download source of more detailed information and recommended practices.

Definitions:

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.

Coriolis flow meter: A measuring device that is capable of working with flow streams to measure the mass rate of flow and the density of the fluid stream.

DP Vessel: Dynamically positioned vessel (DP vessel) means a unit or a vessel which automatically maintains its position and/or heading (fixed location, relative location, or predetermined track) by means of thruster force**.**

Equivalent Circulating Density: The effective density of the circulating fluid in the wellbore resulting from the sum of the pressure imposed by the static fluid column, friction pressure and surface back-pressure.

Flex Joint (A.K.A. Ball joint): Device(s) installed between the bottom of the diverter and the telescopic joint (upper flex or ball joint), in the top section of the LMRP (lower flex or ball joint), or under a keel joint (intermediate flex or ball joint, if used), to permit relative angular movement of the riser and reduce stresses due to vessel motion and environmental forces.

Logging While Drilling (LWD): The measurement of formation properties during the drilling of the borehole by logging tools installed in the BHA.

Lower Marine Riser Package (LMRP): is a mechanical device to protect an oil well located underwater (subsea) and is used during an oil well intervention.

Measurement While Drilling (MWD): The measurement of physical properties while drilling, such as pressure, temperature, and borehole trajectory, by tools installed in the BHA.

Moored Vessels: Offshore floating drilling vessels, which rely on anchors, chain, and mooring lines extended to the ocean floor to keep the vessel at a constant location relative to the ocean floor.

Pressure relief valve (PRV): is a type of safety valve used to control or limit the pressure in a system; pressure might otherwise build up and create a process upset, instrument or equipment failure, or fire. The pressure is relieved by allowing the pressurized fluid to flow from an auxiliary passage out of the system. The relief valve is designed or set to open at a predetermined set pressure to protect pressure vessels and other equipment from being subjected to pressures that exceed their design limits.

Pressure While Drilling (PWD): The measurement of downhole pressure while drilling by a tool installed in the BHA.

Riser margin: The difference between the hydrostatic pressure generated by the mud column in the riser to the mud line and the hydrostatic pressure generated by the seawater column to the mud line.

Tension Ring: Attachment point on the tension joint for the floating vessel tensioning lines.

Underbalanced Drilling (UBD): A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface.

Review Questions:

1. How can a well be hydrostatically underbalanced, but still overbalanced against the formation pressure?
   a. MPD applies Surface Back Pressure (SBP) to compensate for the lack of hydrostatic pressure
   b. MPD removes additional pressure from the well to compensate for the increase in hydrostatic pressure
   c. Wells drilled with MPD are always hydrostatically overbalanced

2. At which depth will 750 psi of Surface Back Pressure (SBP) have the most impact on equivalent mud weight?
   a. MD = 7,160 ft; TVD = 6,600 ft
   b. MD = 14,785 ft; TVD = 13,990 ft
   c. MD = 9,885 ft; TVD = 7,850 ft

3. How can a well be both hydrostatically underbalanced and dynamically overbalanced at the same time?
   a. Hydrostatic pressure can be greater than the formation pressure, but with the pumps on the ECD makes the well flow
   b. Hydrostatic pressure can be less than the formation pressure, but with the pumps on the ECD holds the well back
   c. This is not possible

4. Which of these would affect friction loss in the well?
   a. Atmospheric pressure at the surface
   b. TVD of the well
   c. Measured depth of the well

5. The well is hydrostatically overbalanced. If the RCD is leaking, what should the driller do?
   a. Continue drilling ahead
   b. Pick up off bottom, turn off the pumps, and close the annular
   c. Increase backpressure on the RCD

6. Which of these is a benefit of using Managed Pressure Drilling?
   a. Less likely to have NPT events
   b. Provides better wellbore stability
   c. Mitigates losses and formation damage during drilling
   d. All of the above

7. Using the well control choke, a kick was circulated out of the well with the driller's method. Final Circulating Pressure was held using SBP of 1,110 psi on the casing gauge at 160 gal/min. If we were to continue drilling with MPD at the same mud weight, how much pressure will be required at surface to continue drilling at 375 gal/min?
   a. Less than 1,110 psi
   b. 1,110 psi
   c. More than 1,110 psi

8. Why is measured depth used to calculate annular pressure loss?

a. As the MD of the well increases, so does the friction in the annulus
b. As the TVD of the well increases, the MD of the well decreases
c. As the MD of the well increases, the friction in the annulus decreases

9. What do the initials RCD stand for?

a. Regenerating Counter Drive
b. Residual Contact Device
c. Rotating Control Device

10. Why is the RCD not considered a part of the well control equipment?

a. It is rated for pressures greater than the BOP
b. Rotating Control Devices are always considered well control equipment
c. It is not rated to the same pressures as the BOP

11. When the well is static (not circulating), what should be calculated to keep enough pressure on the well?

a. Leak off test pressure minus the hydrostatic pressure in the well
b. Hydrostatic pressure of the mud, plus whatever back pressure is held with the rotating control device
c. Hydrostatic pressure in the well plus an additional 250 psi of back pressure

12. How can you determine the pressure the rotating head is holding?

a. Open the choke line HCR and read the casing pressure
b. The rotating head always holds one-fifth of the circulating pressure
c. The pressure on the rotating head is equal to the circulating pressure

13. The well is 10,075 ft MD and 9,831 ft TVD. Formation pressure is 7,575 psi. Mud weight is 13.4 ppg. How much back pressure is required to hold back the well?

a. 6,850 psi
b. 750 psi
c. 7,575 psi
d. 555 psi

14. The well is 9,379 ft MD and 7,550 ft TVD. Mud weight in the well is 13.7 ppg.
Annular pressure loss is 400 psi. Surface pressure is 500 psi.
Formation pressure is 6,150 psi. What is the status of this well?

a. The well is hydrostatically underbalanced
b. The well is dynamically overbalanced
c. The well is both hydrostatically underbalanced and dynamically overbalanced

15. When would annular pressure losses increase?

a. When the pump pressure increases, flow properties are increased, and the hole size is smaller
b. When the pump pressure decreases, flow properties are decreased, and the hole size is larger
c. When drilling vertical wells only

Answers:

1	A	When surface back pressure is applied a new "equivalent density" is achieved down hole. Example using 10.0ppg mud weight. Example: 10.0ppg × 0.052 × 10,000 ft = 5200 psi if 300 psi is added from surface equaling a total of 5500psi The equivalent mud weight would be: 5500 psi ÷ 10,000 ft ÷ 0.052 = 10.57 ppg
2	A	The shortest TVD will always equate to a higher equivalent mud weight than deeper TVD's. Example: 500 psi ÷ 10,000 ft ÷ 0.052 = 0.96 ppg 500 psi ÷ 5,000 ft ÷ 0.052 = 1.92 ppg 500 psi ÷ 2,500 ft ÷ 0.052 = 3.84 ppg
3	B	When circulating drilling fluid, the Annular Pressure Loss (APL) is applied to the BHP and is felt in addition to the hydrostatic pressure, once surface back pressure is applied above the hydrostatic and annular friction applied pressure; a new higher BHP can be achieved and maintained as long as SBP is applied to compensate for the loss of APL when shutting down pumps to make connections.
4	C	Measured depth is the determining factor to the APL as every foot of line creates a frictional loss as the fluid moves across the surface area the longer the hole the more friction it creates requiring more pressure to overcome to move fluid at the same rate.
5	B	MPD is used for various well issues, even being hydrostatically overbalanced there was need for SBP on the system. There would be a need to trap pressure to replace the expendable item and then return to drilling operations.
6	D	By being able to control BHP or have "instant mud weight" theoretically gives you the most control over down hole conditions in real time.
7	A	When the GPM was increased using a positive displacement pump the annular frictional pressure would have increased this would require a reduction in SBP to keep BHP constant.
8	A	Measured depth is the determining factor to the APL as every foot of line creates a frictional loss as the fluid moves across the surface area the longer the hole the more friction it creates requiring more pressure to overcome to move fluid at the same rate.
9	C	
10	C	To be considered a barrier, the RCD would have to be able hold a minimum of the Maximum Anticipated Surface Pressure for the well. Most RCDs cannot hold that much pressure.

11	B	The primary barrier envelope during an MPD operation is the hydrostatic pressure in the well, with whatever pressure is being held at the surface.
12	A	Since the casing gauge is directly under the rotating head, any readings we see on the casing gauge should reflect the pressure the rotating head is holding.
13	B	Since the formation pressure is 7,575 psi, we need a total of 7,575 psi to contain the formation. Hydrostatic pressure pushing down: 13.4 ppg × 0.052 × 9,831 ft = 6,850.2408 → 6,850 psi The back pressure required will be the difference between the formation pressure and the hydrostatic pressure, so: 7,575 psi – 6,850 psi = **725 psi**
14	C	Formation pressure is 6,150. The hydrostatic pressure is: 13.7 ppg × 0.052 × 7,550 ft = 5,378.62 → 5,379 psi. Since 5,379 psi < 6,150 psi, the well is underbalanced when we consider hydrostatic alone. However, when the well is dynamic (circulating) we would add the 400 psi of annular pressure loss and the 500 psi of surface pressure. Dynamic bottomhole pressure: 5,379 psi + 400 psi + 500 psi = 6,279 psi Since 6,279 psi > 6,150 psi, the well is dynamically overbalanced. Hence, the well is both hydrostatically underbalanced and dynamically overbalanced.
15	A	Annular pressure loss is the friction the pump must overcome to circulate fluid back up to the surface. Anything that increases the friction or pump pressure will increase annular pressure loss.