

Managed Pressure Drilling Operations with Surface Back-pressure

API RECOMMENDED PRACTICE 92M
FIRST EDITION, SEPTEMBER 2017

ERRATA 1, OCTOBER 2017
ERRATA 2, NOVEMBER 2023
ADDENDUM 1, APRIL 2023



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Introduction

These guidelines (recommended practices) prepared by the IADC Underbalanced Operations and Managed Pressure Drilling (UBO/MPD) Committee, consisting of representatives from various IADC member companies; represent a composite of the practices employed by various operating companies, service companies and drilling contractors in managed pressure drilling operations. In some cases, a reconciled composite of the various practices employed by these companies was utilized. This publication is under the jurisdiction of the American Petroleum Institute, Drilling and Production Operations Subcommittee.

Managed pressure drilling 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, ocean platforms, deep water sites, 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.

Managed Pressure Drilling Operations with Surface Back-pressure

1 Scope

This document provides information for planning, installation, testing and operation of wells drilled with surface back-pressure managed pressure drilling (MPD). This document applies only to drilling rigs with surface blowout preventers (BOPs).

This document considers situations where the total drilling operation is performed balanced or overbalanced, including both hydrostatically overbalanced (no supplemental surface pressure needed to control inflow) and hydrostatically underbalanced (supplemental surface pressure needed to control inflow) systems. See Annex A for guidance on planning and executing influx management using MPD techniques. For underbalanced operations, refer to API 92U.

This document does not cover MPD operations with subsea BOP stacks (see API 92S).

2 Terms, Definitions, and Abbreviations

2.1 Terms and Definitions

For the purposes of this recommended practice the following definitions apply.

2.1.1

common well barrier element

A barrier element that is shared between the primary and secondary barrier envelopes.

2.1.2

drilling window

Pressure difference between the higher of pore/collapse pressure and fracture/fluid losses pressure.

2.1.3

hazard identification

HAZID

The process of identifying hazards in order to plan for, avoid, or mitigate their impacts.

2.1.4

hazard and operability

HAZOP

A structured and systematic examination of processes (existing or planned) in order to identify and evaluate problems that may represent risks to personnel, environment or equipment, or prevent efficient operations.

2.1.5

kick

An unplanned, unexpected influx of liquid or gas from the formation into the wellbore.

2.1.6

kick tolerance

Maximum influx volume at a specific intensity that can be safely circulated out of the well without compromising the weakest point (formation, casing, surface equipment, etc.).

2.1.7**managed pressure drilling****MPD**

An adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore.

2.1.8**non-return valve****NRV**

A valve installed in the drill string that provides positive and instantaneous shutoff against flow or differential pressure from below.

NOTE Sometimes referred to as a float valve.

2.1.9**operator**

The company having legal authority to drill wells and undertake the production of hydrocarbons.

2.1.10**primary well barrier**

The first well barrier that prevents flow from a source.

2.1.11**primary well barrier element**

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.).

2.1.14**secondary well barrier**

Second well barrier that prevents flow from a source.

2.1.15**secondary well barrier element**

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

2.1.16**snubbing**

Adding or removing the drill string or coiled tubing drill string by applying mechanical means to overcome opposing forces created by pressure from the well and or control devices.

2.1.17**stripping**

Adding or removing the drill string or coiled tubing drill string through a sealed control device.

2.1.18**surface back-pressure****SBP**

A managed pressure drilling technique used to actively apply a pressure to obtain a target pressure at a selected point in the wellbore during all drilling operations (drilling, connections, tripping, etc.).

2.1.19**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 environment.

2.1.20**well barrier element**

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

2.1.21**well control event**

An event during well activity that requires activation of the blowout preventer equipment when the operational envelope of the primary barrier is exceeded.

2.2 Abbreviations

BHA	bottom-hole assembly
BHP	bottom-hole pressure
BOP	blowout preventer
BPP	back-pressure pump
CLFP	choke line friction pressure
EU	external upset
FEED	front-end engineering design
HSE	health, safety, and environment
MGS	mud/gas separator
MPD	managed pressure drilling
NRV	non-return valve
P&ID	process and instrumentation diagram
PFD	process flow diagram
PRV	pressure relief valve
RCD	rotating control device
RIH	run-in-hole

3 Managed Pressure Drilling Overview

3.1 Managed Pressure Drilling Objectives

Managed pressure drilling (MPD) is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids.

Any influx incidental to the operation shall be safely contained using an appropriate process. The following are aspects of MPD operations.

- a) MPD process employs a collection of tools and techniques which can mitigate the risks and costs associated with drilling wells that have narrow downhole environmental limits, by proactively managing the annular hydraulic pressure profile.
- b) MPD may include control of back-pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.
- c) When compared to conventional overbalanced drilling, MPD can allow faster corrective action to deal with observed pressure variations. The ability to dynamically control annular pressures facilitates drilling of what might otherwise be technically unattainable prospects.

NOTE Surface back-pressure techniques include, but are not limited to, keeping the borehole completely filled with drilling fluid of the proper weight or density during all operations, exercising reasonable care when tripping pipe out of the hole to prevent swabbing, and keeping track of the amount of drilling fluid put into the hole to replace the volume of pipe removed from the hole during a trip.

3.2 Available Managed Pressure Drilling Solutions

Managed pressure drilling can be divided into the following categories depending on how the open-hole pressure is controlled and managed:

- a) Annular friction systems allowing for constant circulation during drill pipe connections, thereby using annular friction to maintain constant bottom-hole pressure.
- b) Surface pressure systems manipulating annular pressure at surface to control and manage downhole pressures.
- c) Delta energy systems where energy is added to manipulate the wellbore pressure by the use of equipment within the wellbore.
- d) Hydrostatic pressure systems creating a non-uniform hydrostatic profile.
- e) Pressurized mud cap systems used to drill without returns with an annulus fluid column assisted by surface pressure.

3.3 Managed Pressure Drilling Components

This document considers the following as components of MPD systems. These systems include, but are not limited to:

- the rig circulating equipment;
- the drill string;

- drill string non-return valves (NRV);
- BOP equipment;
- pressure control devices (rotating and non-rotating) independent of the conventional rig BOP, such as a rotating control device (RCD) and MPD annular;
- choke and kill lines;
- MPD flow lines;
- choke manifolds;
- gas separation equipment (supplemental);
- control systems;
- pressure, volume flow, mass flow, etc. sensors;
- hazardous gas sensors (H₂S; etc.);
- rig personnel safety and warning devices and signs;
- MPD back-pressure pump or rig pump diverter system.

3.4 Well Barriers

During surface back-pressure managed pressure drilling, the primary well barrier envelope/system can be different from that of conventional drilling operations. The secondary well barrier envelope/system remains the same for MPD operations as for conventional drilling operations. See Section 5 for additional details on well control and well integrity.

3.5 BOP Installation and Use

Installation, testing, and use of blowout preventers (BOPs) and associated well control equipment in MPD operations is similar to conventional drilling operations, and is not included in this publication. This equipment should not be used for RCD seal element change-out unless a design risk assessment has been performed. Refer to API 53 for information regarding installation and testing of BOPs in a conventional drilling operation.

4 Planning

4.1 General

The purpose of this section is to outline the planning and review practices that should be conducted to ensure the safety and integrity of MPD projects.

4.2 Technical Feasibility

The objective of Technical Feasibility study is to determine if MPD is technically feasible and economically viable. A technical feasibility study should be conducted addressing the following:

- Confirm the type of MPD application. Section 3.2 reviews the main MPD techniques generally utilized, although variations to each may be adopted for specific purposes.

- a) Qualified potential service providers should be identified.
- b) Conduct preliminary well design including consideration of the following:
 - drilling concerns, including the rationale for using MPD;
 - operational window, based on pressure prognosis (fracture, formation and collapse pressures), geological hazards and pressure uncertainties;
 - calculations and response for kick/loss tolerance;
 - review all barriers/safety margins during all well operations (e.g. drilling, stripping, displacement, tripping, completions, etc.);
 - casing design and kick tolerance;
 - tubing and completion design;
 - directional plan for the well;
 - drill string/bottom-hole assembly (BHA) configuration;
 - selection of drilling fluid type, weight and rheology;
 - hydraulics modeling and sensitivity analysis for all operations;
 - rig modification requirements;
 - proposed schematics (draft P&ID) of all MPD equipment, including footprints, line sizing, valving, pressure rating, and other design considerations including rig interfaces, weight, etc;
 - surface back-pressure range;
 - geomechanical study;
 - dispensations from regulations needed;
 - transition from MPD operations to conventional operations.

4.3 Front-end Engineering Design

The purpose of this section is to describe and give guidance for the front-end engineering design (FEED) that should be conducted based on the feasibility study. The FEED should include, but not be limited to the following.

- Well design.
- Pressure prognosis plots through the interval showing the available drilling window.
- Ambient, circulating and static temperatures.
- Geologic technical data examining the risks of abnormalities or geologic uncertainties, and the probabilities of larger differences in pore pressure and fracture pressures.
- Casing design.

- Tubing and completion design.
- A description of all drilling concerns.
- Hydraulics modeling.
- Pipe light considerations.
- Transitions between MPD operations and conventional operations.
- a) Equipment.
 - 1) Rig and rig equipment selection:
 - circulating system capability (rates/pressure);
 - condition of drill pipe;
 - selection of pipe rotation devices—top drive versus kelly drive systems;
 - detailed rig modification requirements and interfaces;
 - substructure height to accommodate the additional MPD and wellhead equipment.
 - 2) MPD equipment and/or service provider selection:
 - detailed schematics, such as a process and instrumentation diagram (P&ID), and process flow diagrams (PFD) of all MPD equipment, including footprints, line sizing, valving and design considerations;
 - layout, zoning modification, and interfaces;
 - equipment specifications and pressure ratings of MPD equipment.
 - 3) Specifications of MPD equipment redundancies, including ESD philosophy.
 - 4) Offsite and pre-commissioning testing requirements.
- b) Safety/regulatory.
 - Identification of all project hazards by hazard identification (HAZID) studies including the development of mitigation measures and contingencies;
 - Identify if any dispensations from regulations are needed;
 - Identify third-party certification requirements.
- c) Procedures.
 - A description of the methods available for kick/loss detection and alarms;
 - Procedures and contingency plans should be developed for MPD operations;

- A bridging document should be developed and agreed to by the operator and rig contractor addressing MPD operations which do not comply with either company's well control manual or operational procedures.
- d) Training and competency.
- a training program and objectives should take place for key personnel;
 - a method of competency assurance should be in place.

4.4 Safety Studies and Reviews

Since MPD can result in a different pressure profile in the well compared to conventional operations, a HAZID (or equivalent initial risk assessment technique) should be performed to identify wellbore system risks that would not normally be present. A hazard and operability (HAZOP) study (or equivalent detailed risk assessment technique) should also be performed as a safety and operability review. The purpose of the HAZOP is to critically review the proposed plan to identify and correct, or develop contingency plans for, potential problems. The HAZOP review should be conducted after the detailed design is completed, with sufficient time allowed prior to the start of operations for all action items to be closed out. Reference documents should include the drilling program, equipment specifications and layout, P&ID and/or PFD, procedures, and other industry guidelines.

The IADC *Underbalanced and Managed Pressure Drilling Operations—HSE Planning Guidelines* document provides details on conducting HAZIDs, HAZOPs and other safety studies for MPD operations.

4.5 Emergency Response Plan

An emergency response plan incorporating MPD considerations should be developed for the operation.

4.6 Detailed Design Engineering

The detailed design of an MPD operation and the development of a basis of design should address the following issues.

- a) Current pressure prognosis plots with pore pressures, stability pressures and fracture pressures through the interval showing the available drilling window.
- b) Geologic technical data examining the risks of abnormalities or geologic uncertainties in pore pressure and fracture pressures and reservoir technical data including target formation lithology, height, porosity, permeability, fluid type.
- c) Casing design calculations with safety factors.
- d) Schematics of all MPD equipment, including footprints, line sizing, valving and design considerations (PID or PFD).
- e) Surface circulation system design specifications and redundancies, specifically for MPD implementation;
- f) Rig modification requirement.
- g) Onshore testing requirements.
- h) Field or site requirements to install and operationally test the MPD equipment in a benign environment.

- i) A detailed well monitoring plan for detecting variations in flow rate in and out, including the following:
 - trip tank;
 - pit system procedures;
 - mud return flow trending;
 - the use of flow meters;
 - choke response;
 - logging tools;
 - measurement while drilling (MWD);
 - pressure while drilling (PWD);
 - logging while drilling;
 - gas detection equipment installed;
 - mud sampling procedures;
 - rheology monitoring;
 - alarm philosophy.
- j) Training objectives.
- k) A description of all drilling and reservoir concerns, including the rationale for using non-conventional drilling technology.
- l) Hydraulics modeling plans using a range of anticipated fluid properties, well geometries, drill string configurations and drilling parameters.
- m) H₂S consideration including surface monitoring and alarms, mud additives/scavenger, use of drill pipe corrosion rings, and monitoring.
- n) Identification of all project hazards and the development of mitigation measures and contingencies.
- o) All submissions to and approvals from regulatory authorities.
- p) Development and review of all operational, contingency, and well control procedures.
- q) Data system integration requirements.

5 Equipment

5.1 Managed Pressure Drilling Equipment Considerations

5.1.1 MPD System Components

The final system configuration is dependent on local requirements and the available operational drilling window. MPD systems may include, but are not limited to, the following equipment/processes:

- a) low-pressure riser (above the rotating control device [RCD]);
- b) additional BOP(s) (RCD element change out);
- c) RCD;
- d) pressure-relief valves (PRVs);
- e) MPD choke manifold;
- f) junk catcher;
- g) PRV tank;
- h) flowmeter(s);
- i) pipework and hoses;
- j) isolation valves;
- k) back-pressure pump;
- l) rig pump diverter (RPD);
- m) continuous flow system components;
- n) snubbing systems;
- o) hydraulic model—combinations;
- p) rig pump encoders;
- q) downhole isolation valves;
- r) gas meter;
- s) pressure while drilling (PWD);
- t) mud/gas separator (MGS);
- u) spill protection.

5.1.2 Low-pressure Riser above Rotating Control Device

5.1.2.1 The RCD may be tied back to the rig diverter and shakers via a low-pressure riser. This is often the preferable configuration as it contains any spillage from leaking elements and spray from passing tool joints. A riser also allows a simple conversion to a conventional overbalanced circulation system. Consideration should be given to element change-out if used. Mud level detection in the low-pressure riser is optional.

5.1.2.2 If the riser above the RCD is omitted then consideration for spillage diversion is best achieved by the use of a short stub that can be bolted directly onto the top of the RCD. An outlet from this is required to ensure that accumulated mud is diverted to appropriate drainage.

5.1.2.3 Provision for a drip tray or spill containment device below the RCD to prevent spillage should be considered for both offshore and land operations.

5.1.3 Rotating Control Device or Similar Devices

The following are a number of key operational considerations relating to these devices.

- a) Consideration should be given to the API 16RCD specification regarding pressure rating. The pressure rating is a manufacturing specification for design verification of the RCD only. Operability of the RCD should be determined with the RCD manufacturer.
- b) As a minimum, the RCD sealing elements should be validated in accordance with API 16RCD. Additional testing is advisable for operations with drilling muds (OBM, SBM) that are outside the scope of API 16RCD. The RCD manufacturer should be consulted for test data.
- c) RCD seal elements are expendable items and their pressure capability can decrease with usage. Fit for-purpose testing may be necessary to establish operating pressure values. Rig alignment, pipe condition, drilling fluid, flowing temperature, type of sealing element, etc. can further reduce pressure capability.
- d) An element change out procedure is required. This will include details relating to wellbore isolation, materials handling and working platforms, change out frequency and the need for continuous circulation or not during the operation.
- e) Fluid compatibility between the element and all fluids that it will be exposed to should be verified in advance of operations.
- f) A suitable stock of spare elements should always be on hand and stored/handled in accordance with manufacturer's recommendations. Consideration should be given to having adequate parts and tools to facilitate efficient element change out.
- g) Centered alignment of the drill string inside the RCD is essential for efficient operations and should be confirmed after rig up. Attention should be given to the setting of conductor and surface casing to ensure a vertical stack position with regard to alignment of RCD, BOP, and drill pipe. Eccentric forces caused by pipe "wobble" and/or misalignment can lead to premature failure of the RCD unit. This is even more critical when using a kelly drive. The distance between the rotary and the top element is also a consideration. Pipe wobble can occur due to natural resonances of the drill string and can vary with rotational speed and pipe length above the RCD. During operations it is possible to minimize pipe wobble by manipulating rotary speed.
- h) Drill pipe design and condition can influence element life and should be considered during the planning stages of an MPD operation such as tong marks, sharp kelly edges, hard banding, ID grooves, and tool joint upset angle.

- i) Source properly sized elements for all planned operations and contingencies.
- j) The removal/deployment of the wear bushing is often overlooked. This should be addressed and be in line with BOP testing requirements. Full bore access through the RCD housing is required for certain operations.
- k) RCD shall not be considered as replacement for conventional well control equipment.
- l) The accumulator and or power system used to operate the RCD shall be independent of the rig's standard BOP accumulator system.
- m) Consideration should be given to multiple seal elements in the RCD or alternative means to determine seal element wear.
- n) Gas bleed should be rigged below the RCD sealing element.

5.1.4 Overpressure Protection System

5.1.4.1 A suitable method should be in place to guard against inadvertent overpressure of formation or equipment without fully venting wellbore pressure.

5.1.4.2 Should a relief system be installed the following are issues to be considered when designing the discharge routing from the system:

- a) area classification (see API 500 or API 505);
- b) vertical displacements;
- c) potential for line plugging;
- d) volume measurement;
- e) fluid stream composition including potential of hydrocarbons;
- f) control and maintenance provisions;
- g) relief line reaction forces and restraint;
- h) relief device sizing (see API 520, Part 1);
- i) intervention procedures.

5.1.4.3 Remote indication of activation/status is recommended.

5.1.5 Pressure Relief Valve (PRV) at Equipment Specification Break

Installation of a PRV at a specification break between high- and low-pressure rated equipment is common in MPD systems to protect the lower pressure rated equipment. Depending on the installation, a number of PRVs may be required. The PRVs should be designed in accordance with the following standards as applicable:

- API 14C or ISO 10418;
- API 520;