

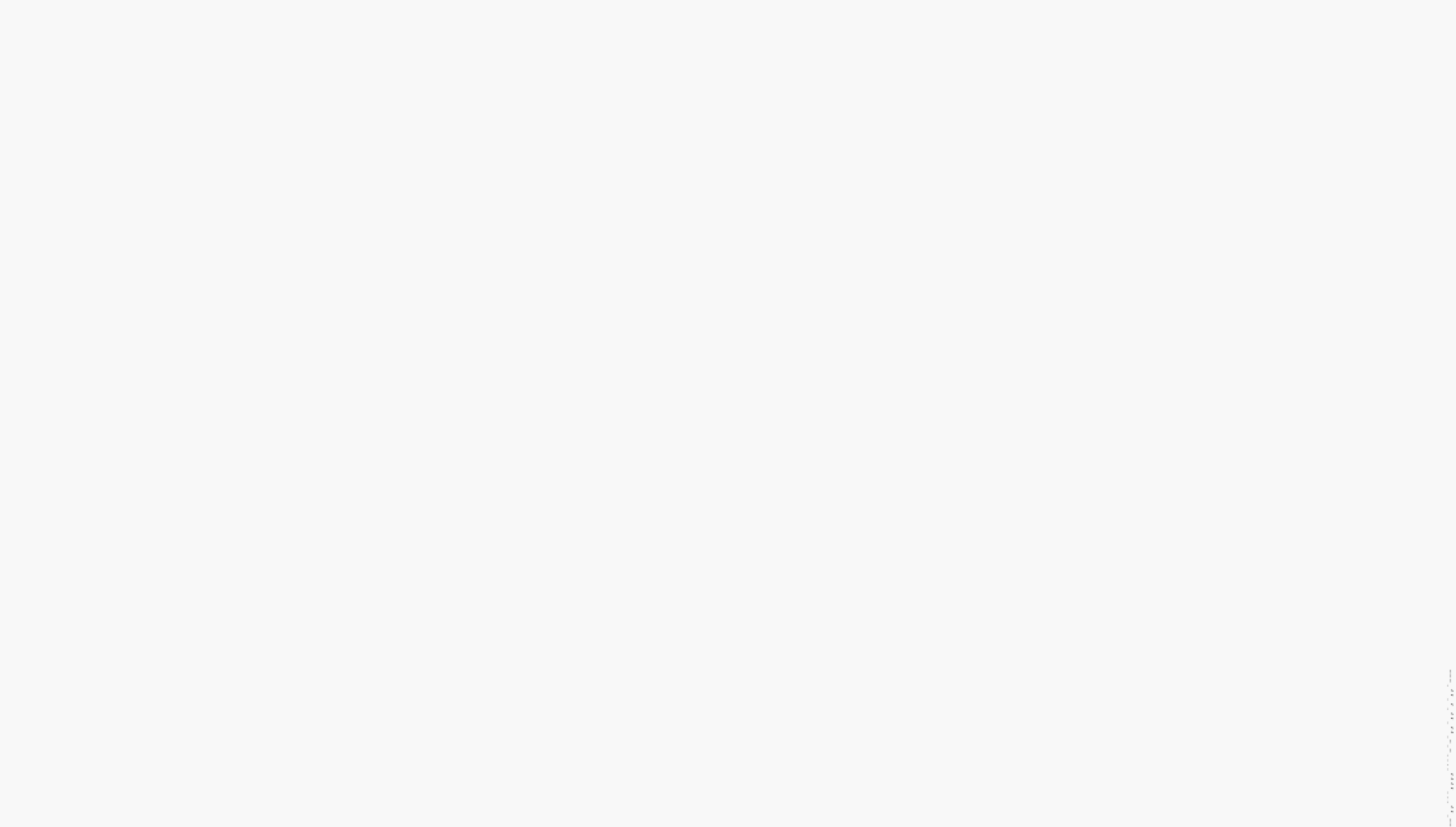
Underbalanced Drilling Operations

API RECOMMENDED PRACTICE 92U
FIRST EDITION, NOVEMBER 2008

REAFFIRMED, APRIL 2013



AMERICAN PETROLEUM INSTITUTE



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Upstream Segment

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Recommendations presented in this publication are based on this extensive and wide-ranging industry experience. The goal of these recommended practices is to assist the oil and gas industry in promoting personnel safety, public safety, integrity of the underbalanced drilling equipment, and preservation of the environment for land and offshore underbalanced drilling operations and these recommended practices are published to facilitate the broad availability of proven, sound engineering and operating practices. This publication does not present all of the operating practices that can be employed to successfully conduct underbalanced drilling operations. Practices set forth herein are considered acceptable for accomplishing the job as described; however, equivalent alternative installations and practices may be utilized to accomplish the same objectives. The formulation and publication of API recommended practices is not intended, in any way, to inhibit anyone from using other practices. Furthermore, individuals and organizations using these recommended practices are cautioned that underbalanced drilling operations must comply with requirements of applicable federal, state, or local regulations and these requirements should be reviewed to determine whether violations may occur.

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Foreword

These guidelines (recommended practices), prepared by the IADC Underbalanced Operations and Managed Pressure Drilling 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 underbalanced drilling operations. In some cases, a reconciled composite of the various practices employed by these companies was utilized. The Committee acknowledges the Canadian Association of Drilling Contractors (CAODC), the Canadian Association of Petroleum Producers (CAPP), Petroleum Services Association of Canada (PSAC) and the Alberta Energy Utilities Board (AEUB), and in particular the Drilling and Completions Committee (DACC) for their effort in developing guidelines related to underbalanced drilling in the Canadian environment, which are the basis for this document. This publication is under the jurisdiction of the American Petroleum Institute, Upstream Segment's Executive Committee on Drilling and Production Operations.

Underbalanced drilling is used globally on new wells and to deepen or side-track from existing well bores. Underbalanced 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, deepwater 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 geological formations including oil and gas reservoirs and on sour wells thus driving the need for globally accepted standards and safe operating practices.

Furthermore, this publication includes use of the verbs "shall" and "should" whichever is deemed the most applicable for the specific situation.

For the purposes of this publication, the following definitions are applicable:

Shall: As used in a standard, "shall" denotes a minimum requirement in order to conform to the specification.

Should: As used in a standard, "should" denotes a recommendation or that which is advised but not required in order to conform to the specification.

Changes in the uses of these verbs are not to be effected without risk of changing the intent of recommendations set forth herein.

Recognizing the varying complexity and risk associated with drilling wells classified as IADC Level 1 as compared to IADC Level 4 or 5, this document is prepared from the perspective of an IADC Level 1 or 2 well. Therefore, the end-user is advised to replace the verb "should" with "shall" for wells classified as IADC Level 4 or 5.

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Underbalanced Drilling Operations

1 Scope

1.1 Purpose

The purpose of these recommended practices is to provide information that can serve as a guide for planning, installation, operation and testing of underbalanced drilling equipment systems on land and offshore drilling rigs [barge, platform, bottom-supported, and floating with surface blowout preventers (BOP) installed] thereby ensuring consideration of personnel safety, public safety, integrity of the underbalanced drilling (UBD) equipment, and preservation of the environment for onshore and offshore UBD operations (including tripping of drill string).

The UBD system is composed of all equipment required to safely allow drilling ahead in geological formations with pressure at surface and under varying rig and well conditions. These systems include: the rig circulating equipment, the drill string, drill string non return valves (NRV), surface BOP, control devices (rotating or non-rotating) independent of the BOP, choke and kill lines, UBD flowlines, choke manifolds, hydraulic control systems, UBD separators, flare lines, flare stacks and flare pits and other auxiliary equipment. The primary functions of these systems are to contain well fluids and pressures within a design envelope in a closed flow control system, provide means to add fluid to the wellbore, and allow controlled volumes to be withdrawn from the wellbore.

1.1.1 Managed pressure drilling (Category A) and mud cap drilling (Category C) techniques as defined in the IADC *Well Classification System for Underbalanced Operations and Managed Pressure Drilling* are not included in this publication. The phrase managed pressure drilling or the acronym MPD is only used in this document in the context of the IADC *Well Classification System*.

1.1.2 Sub-sea BOP stacks and marine risers are not dealt with in this document.

1.2 Well Control

During UBD and tripping operations, primary well control is based on flow and pressure control using specialized equipment and procedures. If an unplanned event occurs, secondary well control is provided by the rig's BOP equipment as in conventional drilling and tripping operations. Procedures and techniques for conventional well control are not included in this publication (refer to API 59).

1.3 Blowout Preventer (BOP) Installation

Procedures for installation and testing of conventional and sub-sea BOPs are not included in this publication unless alternative procedures are recommended for the UB operation. Refer to API 53 for information regarding installation and testing of BOPs in a conventional drilling operation.

1.4 Installation of Underbalanced Drilling Control Devices (UBD-CDs)

Procedures for installation and testing of both rotating and non-rotating UBD-CDs are included in this publication.

1.5 Equipment Arrangements

Recommended equipment arrangements, as set forth in this publication, are adequate to meet most well conditions. It is recognized that other arrangements may be equally effective and can be used in meeting well requirements safely and efficiently.

1.6 Extreme Temperature Operations

Underbalanced operations (UBO) may be conducted in areas of extremely low and high ambient air temperatures. As a result, these considerations are area specific and shall be evaluated on a project-by-project basis. Where appropriate, ambient air temperature considerations are addressed within this document.

1.7 Control System Accumulator Capacity

Additional BOP equipment is sometimes required for an underbalanced operation. If additional BOP equipment is added to an existing system, the accumulator capacity shall be verified per API 53, which provides capacity guidelines to ensure that the volumetric demands of the control system piping, hoses, fittings, valves, BOPs, and other related equipment are met.

2 Referenced Standards

2.1 Standards

The following standards contain provisions, which through reference in this text constitute provisions of this standard. All standards are subject to revision and users are encouraged to investigate the possibility of applying the most recent editions of the standards indicated below.

API Specification 5CT/ISO 11960:2004 ¹, *Specification for Casing and Tubing*

API Specification 5D, *Specification for Drill Pipe*

API Specification 6A/ISO 10423:2003, *Specification for Wellhead and Christmas Tree Equipment*

API Specification 7, *Specification for Rotary Drill Stem Elements*

API Recommended Practice 7C-11F, *Recommended Practice for Installation, Maintenance, and Operation of Internal-Combustion Engines*

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

API Specification 7K/ISO 14693:2003, *Specification for Drilling and Well Servicing Equipment*

API Recommended Practice 7L, *Inspection, Maintenance, Repair and Remanufacture of Drilling Equipment*

API Specification 7NRV, *Specification on Non-Return Valves*

API Recommended Practice 14C, *Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms*

API Specification 14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems*

API Recommended Practice 14F, *Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations*

API Specification 16A/ISO 13533:2001, *Drill Through Equipment*

¹ International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211, Geneva 20, Switzerland, www.iso.org.

API Specification 16C, *Choke and Kill Systems*

API Specification 16D, *Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

API Specification 16RCD, *Drill Through Equipment—Rotating Control Devices*

API Recommended Practice 17B/ISO 13628-11:2007, *Recommended Practice for Flexible Pipe*

API Specification 17J/ISO 13628-1:2006, *Specification for Unbonded Flexible Pipe*

API Specification 17K/ISO 13628-10, *Specification for Bonded Flexible Pipe*

API Recommended Practice 53, *Blowout Prevention Equipment Systems for Drilling Wells*

API Recommended Practice 64, *Diverter Systems Equipment and Operations*

API Recommended Practice 500, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2*

API Recommended Practice 576, *Inspection of Pressure-relieving Devices*

AEUB Interim Directive ID 90-1 ², *Completion and Servicing of Sour Wells*

AEUB Interim Directive ID 94-3, *Underbalanced Drilling*

AEUB Interim Directive ID 97-6, *Sour Well Licensing and Drilling Requirements*

AEUB Informational Letter IL 88-11, *Shop Servicing and Testing of Blowout Preventers and Flexible Bleed-Off and Kill Line Hoses*

ASME Boiler and Pressure Vessel Code ³, *Section V: Nondestructive Testing, Article 5: Ultrasonic (UT) Examination Methods for Materials and Fabrication*

ASME Boiler and Pressure Vessel Code, *Section VIII: Pressure Vessels*

- *Division 1: Appendix 4—Rounded Indication Charts Acceptance Standard for Radiographically Determined Rounded Indications in Welds*
- *Division 2: Alternative Rules, Appendix 4: Design Based on Stress Analysis*
- *Division 2: Alternative Rules, Appendix 6: Experimental Stress Analysis*

ASNT SNT-TC-1A ⁴, *Personnel Qualification and Certification in Nondestructive Testing*, 1984 or latest Edition

ASTM A193 ⁵, *Alloy-Steel and Stainless Steel Bolting Materials*

² Alberta Energy and Utilities Board, 640-5th Avenue SW, Calgary, Alberta, Canada T2P 3G4.

³ American Society for Mechanical Engineers, 3 Park Avenue, New York, New York 10016-5990, www.asme.org.

⁴ American Society for Nondestructive Testing, Inc., 1711 Arlingate Lane, P.O. Box 28518, Columbus, Ohio 43228-0518, www.asnt.org.

⁵ American Society for Testing and Material, Inc., 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19103, www.astm.org.

ASTM D412, *Standard Test Methods for Vulcanized Rubber and Thermoplastic Elastomers—Tension*

ASTM D471, *Standard Test Method for Rubber Property—Effect of Liquids*

ASTM D2240, *Standard Test Method for Rubber Property—Durometer Hardness*

ASTM G111, *Standard Guide for Corrosion Tests in High Temperature or High Pressure Environment, or Both*

Enform IRP 1⁶, *Critical Sour Drilling*

Enform IRP 2, *Completing and Servicing Critical Sour Wells*

Enform IRP 4, *Well Testing and Fluid Handling*

Enform IRP 6, *Critical Sour Underbalanced Drilling*

Enform IRP 15, *Snubbing Operations*

Enform IRP 18, *Hazardous fluids and processes*

GRI 97/0236⁷, *Underbalanced Drilling Manual*

IADC⁸, *Well Classification System for Underbalanced Operations and Managed Pressure Drilling*

NACE MR 0175⁹, *Petroleum and Natural Gas Industries Materials for Use in H₂S-containing Environments in Oil and Gas Production*

— *Part 1: General Principles for Selection of Cracking-resistant Materials*

— *Part 2: Cracking-resistant Carbon and Low Alloy Steels, and the Use of Cast Irons*

— *Part 3: Cracking-resistant CRAs (Corrosion-resistant Alloys) and Other Alloys*

NACE TM 0187-87, *Standard Test Method for Evaluating Elastomeric Materials in Sour Gas Environments*

NFPA Standard 11¹⁰

3 Definitions/Abbreviations and Descriptions

3.1 Definitions

3.1.1

API gravity

A special function of relative density (specific gravity) used in the accurate determination of the gravity of petroleum and its products for the conversion of measured volumes at the standard temperatures of 60 °F (15.56 °C) represented by:

$$\text{API gravity (degrees)} = (141.5/\text{specific gravity } 60^\circ\text{F}/60^\circ\text{F}) - 131.5.$$

3.1.2

barrier

Any system that is used to contain well fluids within the wellbore. The term “first barrier” is used to describe systems providing first-line containment. The term “second barrier” is used to describe systems providing backup to the first-line system. A barrier may be closed, e.g. bridge plug/cement, or it may be normally open but at readiness to close e.g. BOP.

⁶ Enform, 1538-25th Avenue NE, Calgary, Alberta, Canada T2E 8Y3, www.enform.ca.

⁷ Gas Research Institute, 8600 West Bryn Mawr Avenue, Chicago, Illinois 60631.

⁸ International Association of Drilling Contractors, P.O. Box 4287 Houston, Texas 77210-4287, www.iadc.org.

⁹ National Association of Corrosion Engineers, 1440 South Creek Drive, Houston, Texas 77084-4906, www.nace.org

¹⁰ National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169, www.nfpa.org

3.1.3**bleed-off line**

Part of the pressure containing equipment on a snubbing stack that provides a means of bleeding off trapped wellbore pressure.

3.1.4**certified**

Infers that components of the pressure containing system have been manufactured and maintained under a quality program to ensure conformance with their design specification.

During shop servicing, certification must be performed by an API or ISO-licensed manufacturer or company or technical expert that meets the requirements of IRP 2, Section 10.2.2.

3.1.5**circulating media**

Includes both injected and produced fluids, as well as their mixtures.

3.1.6**circulation system**

The circuitous path that the drilling fluid travels. Beginning at the main rig pumps, the primary components include the surface piping, the standpipe, the rotary hose, the kelly or the top drive system, the drill pipe, the bottomhole assembly (BHA) including the drill collars, motor or turbine (if applicable) and bit nozzles, the various annular geometries of the open hole and casing strings, the BOPs, the RCD, the flowline, the UBD choke manifold, the fluids-gas-solids handling equipment, the drilling/production fluid storage tanks, the venting/flaring/recovery system for produced gas, the centrifugal pre-charge pumps and back to the main rig pumps.

3.1.7**closed circulation system**

A system where the circulating medium is managed such that all gases are vented to a flare system or otherwise safely vented. Systems using gas recovery to process or recycle gas represent an enhancement to the closed circulating system.

3.1.8**closed cup flash point****CCFP**

ASTM D93 Pensky-Martens closed cup tester.

3.1.9**coiled tubing****CT**

Steel pipe flexible enough to be stored on and deployed from a reel. Used to replace jointed pipe in certain types of drilling, completion, and workover operations.

3.1.10**coiled tubing (CT) drill string**

Includes all equipment from the drill bit up to and including the rotating joint on the CT spool. The drill string refers to all BHAs, continuous tubing and pressure control devices in the continuous tubing. The drill string also refers to any fishing BHA required to be run into the hole to recover portions of CT drill string inadvertently left in the well.

3.1.11**coiled tubing (CT) stripper**

The uppermost packing element on the coiled tubing BOP stack that enables the CT to be deployed into the well under pressure.

3.1.12**consequence mitigation and recovery preparedness measures**

Necessary to limit the consequences of the hazardous event or aimed at reinstating or returning to a normal situation.

3.1.13**control device****CD**

A drill-through device with a seal that contacts and seals against the drill string for the purpose of controlling the pressure or fluid flow to surface; can be either rotating or non-rotating.

3.1.14**critical sour well**

Any well from which the maximum potential H₂S release rate is greater than:

- 0.01 cubic meters per second (m³/s) or greater and less than 0.1 m³/s and which is located within 500 meters (m) of the boundaries of an urban center;
- 0.1 m³/s or greater and less than 0.3 m³/s and which is located within 1.5 km of the boundaries of an urban center;
- 0.3 m³/s or greater and less than 2.0 m³/s and which is located within 5 km of the boundaries of an urban center; or
- 2.0 m³/s.

3.1.15**diverter/annular preventer**

An annular-type preventer that is designed to be closed around the drill string to contain wellbore pressure, and may be a rotating or non-rotating type, and designed for various working pressure ratings depending on manufacturer specifications.

3.1.16**downhole isolation valve****DIV**

A valve designed to be placed in the wellbore to isolate formation pressures enabling equipment to be run and recovered from a well.

3.1.17**drill pipe**

Drill pipe refer to traditional drill pipe with tool joints and tubing with connections suitable for drilling service.

3.1.18**drill string**

Includes all equipment from the drill bit to and including the stabbing valve at surface. The drill string refers to all BHAs, jointed or coiled tubulars and pressure control devices run into the hole. The drill string also refers to any fishing BHA required to be run into the hole to recover portions of drill string inadvertently left in the well.

3.1.19**elastomer seals**

All elastomeric seals that contain any wellbore pressure within the pressure containing system. These seals are not limited to the ram type preventers but include all seals (O-ring, ram shaft, etc.) exposed to the wellbore environment that prevents the wellbore pressure from escaping outside the pressure containing system.

3.1.20**emergency planning zone****EPZ**

A geographical area surrounding a well, pipeline or production facility containing hazardous materials that requires specific emergency planning by the operator. The EPZ represents a geographical area where first-level response actions might be required in the event of an incident to mitigate a severe threat to public safety.

3.1.21**emergency shutdown valve****ESD**

A remotely-actuated safety device used to isolate well fluids from personnel and equipment and prevent the severity of the incident escalating due to fire and/or explosion.

3.1.22**equalizing line or loop**

The pressure containing line on the snubbing stack that provides the means to equalize pressure between the snubbing stack and the wellhead during snubbing operations.

3.1.23**hazard identification studies****HAZID**

Designed to identify all potential hazards, which could result from operation of a facility or from carrying out an activity. A HAZID is based on the safety and operability review (HAZOP).

3.1.24**high closing ratio valve****HCR valve**

A remote hydraulically controlled valve used on the BOP stack.

3.1.25**HSE**

Health, safety and environment.

3.1.26**independent barrier**

A barrier that is not reliant on another barrier to ensure pressure integrity.

3.1.27**inert gas**

Gases that exhibit stability and extremely low or no reaction rates, such as helium and nitrogen.

3.1.28**integrity of the drill string**

When there is pressure integrity between circulated fluids inside the drill string and wellbore fluids or the atmosphere outside the drill string, integrity of the drill string requires pressure integrity of all components from the swivel to the drill bit during rotary drive applications, from the top drive unit to the drill bit during top drive applications, and from the rotary joint on the CT reel to the drill bit during CT drilling applications. Loss of containment may be caused by a failure of any tubular component.

3.1.29**kick**

An unplanned, unexpected influx of liquid or gas from the formation into the wellbore, where the pressure of fluid in the wellbore is insufficient to control the inflow. If not corrected, can result in a blowout.

3.1.30**kill weight fluid**

A fluid with a density that is high enough to produce a hydrostatic pressure at the point of influx into a wellbore to shut off any further flow into the well.

3.1.31**leak tight**

A condition of no observable flow across a barrier, no pressure build-up downstream of a barrier and/or no pressure loss upstream of a barrier.

3.1.32**logging while drilling****LWD**

The measurement of formation properties during the excavation of the hole, or shortly thereafter, through the use of tools integrated into the BHA.

3.1.33**managed pressure drilling****MPD**

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 to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.

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

3.1.34**maximum anticipated surface pressure****MASP**

Equal to the original reservoir pressure minus the gas gradient. This value can only be reduced if a qualified reservoir specialist endorses a reduction based on factual data.

3.1.35**measurement while drilling****MWD**

The measurement of the inclination and azimuth during the excavation of the hole through the use of accelerometers and magnetometers integrated into the BHA.

3.1.36**non-return valve****NRV**

A type of back-pressure valve installed in the drill string that provides positive and instantaneous shutoff against differential pressure from below thus ensuring continuous control of fluid flow from the drill string during UBD or conventional drilling operations.

NOTE The more common name for an NRV is a “drill string float valve.” The use of the term NRV instead of the more common name was adopted to highlight that in a UBD operation the valve:

- a) is primary well control equipment installed as an integral part of the drill string;
- b) is non-ported;
- c) is required to be run in a special sub or landing nipple; and
- d) may have trapped pressure below it when retrieved at surface and therefore, requires a special tool to safely relieve trapped pressure.

3.1.37

NRV sub/NRV landing nipple

A receptacle with internal sealing surfaces in which an NRV may be installed.

3.1.38

NRV equalizing head

Used to equalize the NRV on surface, venting any trapped pressure prior to the removal of the NRV from the drill string.

3.1.39

open cup flash point

OCFP

ASTM D92 Cleveland open cup test. The lowest temperature flash point corrected to a barometric pressure of 101.3 kPa, at which application of a test flame causes the vapor of a specimen to ignite under specified conditions of test, and is used primarily for viscous materials having a flash point of 79 °C and above.

3.1.40

operator

The operating company holding the license to explore for or exploit the hydrocarbon reserves.

3.1.41

packing element

Sealing element between the UBD-CD and the drill string.

3.1.42

pipe-light

A condition that occurs when the force inside the well-bore acting to push the drill string out, is greater than the force acting to keep it in the well bore.

3.1.43

pipe-light depth

The depth in the wellbore above which a pipe-light condition may occur.

3.1.44

piping and instrumentation diagram

P&ID

A diagram which shows the interconnection of process equipment and the instrumentation used to control the process. It is the primary schematic drawing used for laying out a process control installation. In the process industry, a standard set of symbols is used to prepare drawings of processes.

3.1.45**pressure containment system**

Includes all equipment from the top wellhead flange to the downstream side of the choke, and specifically the BOP stack, snubbing stack, CT stack and pressure deployment system including all bleed lines and the blowout prevention control system.

3.1.46**pressure deployment**

The process by which drill string components or CT drill string components are deployed into or recovered from the well while the well is under pressure.

3.1.47**primary well control**

In an overbalanced drilling operation, is the drilling fluid system (including the fluid) designed to maintain the wellbore in an overbalanced condition. In a UBD operation, it is defined as the equipment and systems used to maintain the pressure and flow at surface within the design parameters.

3.1.48**process flow diagram****PFD**

A diagram commonly used to indicate the general flow of the drilling and return fluids through processes and equipment. The PFD displays the relationship between *major* equipment of a facility and does not show minor details such as piping details and designations.

3.1.49**Reid vapor pressure****RVP**

The test method (ASTM D323) used to determine vapor pressure of volatile petroleum liquids at 37.8 °C (100 °F) with an initial boiling point above 0 °C (32 °F).

3.1.50**risk**

The product probability that a specified undesired event will occur and the severity of the consequences. Determining the risk of a specified event requires information on the likelihood of the hazardous event occurring and the severity of the consequences.

3.1.51**rotating control device****RCD**

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

3.1.52**safety and operability review****HAZOP**

Designed to review process systems and operating procedures to confirm whether they will operate as intended without introducing any avoidable hazards.

3.1.53**safety critical**

Processes, equipment or supervisory personnel whose failure or malfunction or negligence may result in death or serious injury.

3.1.54**secondary well control**

Equipment and systems used in drilling operations to prevent uncontrolled flow at surface in the event of a loss of primary well control.

3.1.55**snubbing**

Adding or removing the drill string or CT drill string by applying mechanical means to overcome opposing forces created by pressure from the well and/or control device.

3.1.56**sour well**

For purposes of underbalanced drilling, HSE and this recommended practice (RP), this term refers to any well with an H₂S content of greater than 10 ppm; for purposes of equipment, refer to NACE MR 0175.

3.1.57**sour**

An H₂S concentration equal to or greater than 10 ppm, and is consistent with 8-hour occupational exposure limit (OEL) for workers exposed to H₂S.

3.1.58**stripping**

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

3.1.59**threats**

A “threat” is defined as, something that could potentially cause the release of hazard and result in an incident, whereas a “barrier,” is the means to prevent a threat or combination of threats from occurring. Used in this context, barriers may be physical (shields, isolation, separation, protective devices) or non-physical (procedures, alarm systems, training, drills).

3.1.60**top kill**

An operation where a weighted pill is placed in the wellbore where the combined hydrostatic pressure of the various fluid densities will exceed the bottomhole pressure (BHP).

3.1.61**UBD flow control equipment**

Comprises the UBD fluid pump, circulating system piping including the stand pipe and the rotary (kelly) hose as appropriate, a UBD control device (UBD-CD), the drill pipe (DP), NRVs and a surface system for controlling and processing return flow-rates while under pressure.

3.1.62**underbalance**

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

3.1.63**underbalanced**

Conducted in a state of underbalance.

3.1.64**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.

3.1.65**underbalanced operations****UBO**

A well construction or maintenance 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.

3.1.66**well control**

The management of the hazards and the effects of pressures and flow encountered during the exploration and exploitation of hydrocarbon accumulations.

3.1.67**well control event**

In an overbalanced drilling operation, this occurs when there is an unexpected flow into the wellbore. In a UBD operation, this occurs when the surface pressure, return flow rate, or wellhead temperature exceeds the surface equipment design specification.

3.1.68**wellsite supervisor**

The operator's designated principle representative at the wellsite whether or not that person is the operator's employee.

4 Planning

4.1 Scope

A UBD project is a complex combination of simultaneous drilling and production operations. The purpose of this section is to outline the planning and review practices that should be conducted to ensure the technical and safety integrity of the project.

4.2 Technical Feasibility

Prior to proceeding with a UBO project, decisions will likely be made as to whether CT or drill pipe will be used as the drill string for the project, whether lift gas will be required, and will any required gas injection be via concentric casing and/or down the drill string. Fluid types (lift gas and drilling fluid) will be evaluated and selected. Casing design will be assessed against requirement for maximum potential shut in pressures and effect of casing wear on this design requirement.

4.2.1 Flow modelling should be done to determine technical feasibility and establish the operating envelope. UBD flow modeling is an integral element in the preliminary engineering and circulating system design stages for any UBD project. Flow modeling should be done at both the top of the UBD section and at total depth (TD) of the section (assuming no reservoir inflow) to determine:

- whether a stable underbalanced or near-balanced condition can be achieved;

- whether adequate annular velocities for hole cleaning can be achieved in an underbalanced circulating system;
- whether the operating performance of the downhole motor or turbine is negatively affected by the underbalanced circulating conditions.

4.2.1.1 An operating envelope exists only for those combinations of liquid, gas and surface back pressures that meet the pressure draw down requirement for the project wells, provides the minimum liquid velocity required for hole cleaning and are within the operating limits of the motor or turbine. Figure 1 is an example of a steady state UBD operating envelope

4.2.1.2 Once the operating envelope is confirmed, modeling should be repeated with reservoir inflow based on the minimum inflow, the expected inflow and the maximum inflow as provided by the asset owners.

4.2.1.3 Both annular flow and injection should be modeled to effectively determine well controllability and UBD equipment specifications. Well controllability is determined by establishing the effect on the bottomhole pressure (BHP) to changes in the injection parameters (gas and liquid rates) or the surface choke setting.

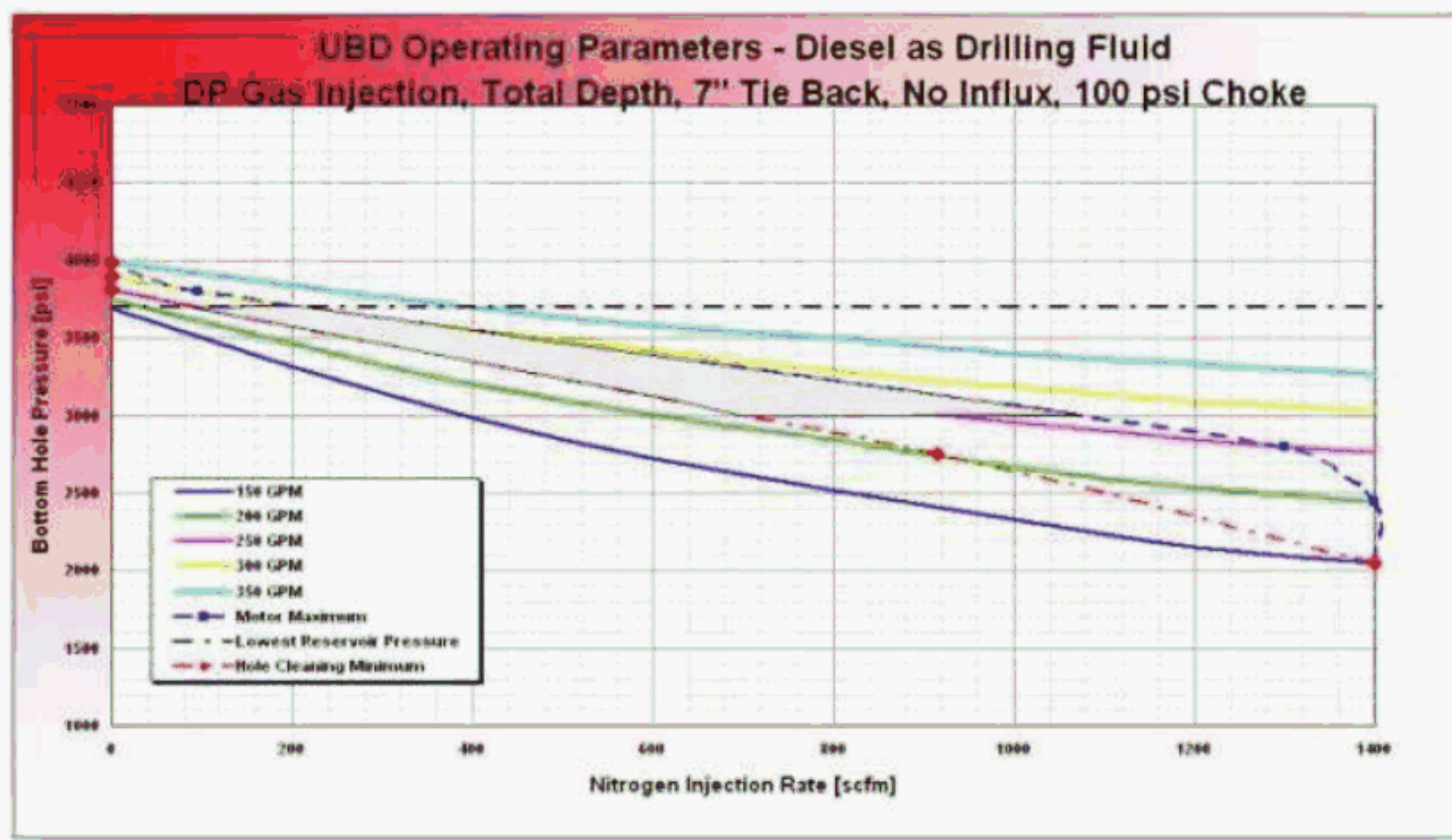


Figure 1—Example of a Steady State Subsurface Operating Envelope

4.2.2 A competent drilling engineer shall do the following.

4.2.2.1 Confirm that the casing design is capable of handling the maximum potential loads with appropriate safety factors. This shall include but not be limited to structural assessment of conductor, wellhead and BOP loads due to UBD-specific load conditions (axial load, internal pressure) covering maximum anticipated loads. The drilling or operations program should clearly state that this has been done.

4.2.2.2 Determine the maximum allowable casing wear that shall not be exceeded without additional engineering review and assessment. This information should be included in the drilling or operations program.

4.2.2.3 Classify the well to be drilled underbalanced using the IADC *Well Classification System for Underbalanced Operations and Managed Pressure Drilling* that combines the level of complexity/hazard and the UBD application type. This information should be included in the drilling or operations program.

4.2.3 Plans and procedures for the underbalanced well should be appropriate to the IADC well classification level and should include a robust contingency plan for the next level up.

4.3 Rig Equipment Selection

UBD operations can be performed using a conventional drilling rig, work-over rig, or with a snubbing unit/hydraulic work-over unit, all using jointed pipe. A CT or “hybrid” rig can also be used. Each method has its advantages and disadvantages and the final choice usually depends on equipment availability, cost and risk mitigation.

4.3.1 General Rig Selection Considerations

Key factors in evaluating standard rig components for UBD application include:

- substructure height to accommodate the additional UBD and wellhead equipment;
- circulating system capability (rates/pressure);
- condition of kelly hose;
- condition of drill pipe;
- BOP equipment;
- adequate accumulator capacity for functioning additional BOP rams and valves when required;
- condition of electrical systems and adherence to explosion hazard zone classification.

4.3.2 Selection of Pipe Rotation Devices—Top Drive vs. Kelly Drive Systems

A top drive system is often the preferred system for horizontal underbalanced drilling. However, drilling underbalanced with a kelly drive is possible both operationally and from an HSE perspective. Each system has advantages and disadvantages; availability, operational efficiency, risk mitigation and cost are usually the deciding factors.

a) Top drive system.

- Enables drilling with stands instead of singles and reduces the number of connections required in the underbalanced section. The potential for going overbalanced due to pump-on-pump-off transient pressure instability during connections is decreased.
- From an HSE perspective, less connections translates into less exposure from handling pipe and picking up and racking the kelly for each connection.
- Enables pumping into and out of the hole on high-pressure, high-rate gas wells to reduce the surface pressures and reduce wear on the CD packing elements.
- Allows easy back reaming, often an advantage in drilling horizontal wells; short wiper trips to clear build-up of cuttings beds in the horizontal section.

b) Kelly drive system.

- If a kelly is used it shall be hexagonal, not square, to get proper sealing with the RCD packer element.

- With proper selection of the packer element compound and proper installation of the RCD, increased wear due to the use of a kelly and/or leaking between the kelly and the RCD should not be an issue.
- Most kellys have sharp edges and tractor marks, which can negatively impact the life of the RCD packer element. These are a result of the manufacturing process. The manufacturer or a machine shop should machine these off (smoothed).

4.3.3 In many areas, threaded connections are the norm on the standpipe and the kelly hose connections are hammer union type connections, these shall conform to applicable regulatory requirements. However, in the absence of applicable regulatory requirements,

4.3.3.1 Flanged standpipe and or kelly hose connections rather than hammer union connections shall be used on offshore operations.

4.3.3.2 If continuous gas injection via the standpipe is required, kelly hose with integral flanged end connections or integral hammer unions should be considered.

4.4 Safety Studies and Reviews

4.4.1 Hazard Identification

After the decision is made to proceed with a UBO Project, but prior to commencement of detail design work, a HAZID review should be conducted. Primary benefit of HAZID is that early identification and assessment of the critical HSE hazards provides essential input to project decisions.

4.4.1.1 Purpose

The purpose is to recognize the importance of HSE considerations on the fundamental, often non-HSE-related, decisions that are usually made at the beginning of a project. It allows:

- a) consideration of HSE implications of alternative designs;
- b) changes to philosophy/design before significant financial commitments are made;
- c) identification of specific hazards and threats within the project life-cycle phase;
- d) preparation of an inventory of project-specific HSE hazards and threats;
- e) focus of the design effort on HSE risk mitigation, as well as compliance with operating company and regulatory requirements.

4.4.2 Safety and Operability Review (HAZOP)

HAZOP is a structured hazard identification technique using a multi-disciplined team. It has become accepted as the main technique to identify the process hazards associated in the design and operation of UBD circulating systems. HAZOPs have been used extensively on many UBD projects; specifically aimed at the design and operation of, but not limited to, the following:

- the surface separation system;
- the fluid system including mud pumps mist pumps, transfer pumps, etc.;
- the BOP system;

- the complete well including the casing design and appropriate safety factors;
- the lift gas supply and injection system;
- the snubbing system;
- the drill string, including bottomhole assembly (BHA) and drill-pipe isolation;
- the complete UBD system, including interfaces and logistics;
- completion equipment including downhole isolation (barriers).

4.4.2.1 Timing

After the detailed design for the UBO project is completed but prior to commencement of operations, a detailed HAZOP review should be conducted.

4.4.2.2 Purpose

The purpose is to critically review the proposed plan to identify and correct, or develop contingency plans for, potential problems. Although this document addresses general situations, each project is unique and should be reviewed in detail.

The review also provides a secondary function as a training tool for personnel (including field personnel) involved in the project.

4.4.2.3 Participants (the “team”) should include:

- technical staff who selected and designed the process equipment and prepared the operations program;
- site supervisors, operator, contractors (including subcontractors);
- senior operations personnel responsible for the operation;
- a competent HAZID/HAZOP facilitator.

4.4.2.4 Reference documents should include the drilling program, equipment specifications and layout, P&ID and/or PFD, procedures, practices as outlined in 4.5 of this document, and other industry guidelines.

4.4.2.5 The team should conduct an orderly, systematic review of the project plan to assess and identify possible failure scenarios and appropriate mitigation measures. If not already included in the project plan, the plan shall be modified to include appropriate mitigation controls.

4.4.2.6 The team should also conduct a detailed documented review of the operations program, which should be approved/signed by the senior operations person (i.e. superintendent, operations manager) responsible for its execution.

4.4.2.7 All action items identified and documented shall be tracked and closed out prior to start of operations.

4.4.2.8 If the operator has conducted a HAZOP review for a previous but similar UBD project, the review may be referenced and used as the basis for the new project, (except for critical sour wells). However, the validity of the HAZOP should be reviewed.

4.4.2.9 A detailed HAZOP review shall be conducted for all critical sour well UBD projects. Each wellsite operation may be unique (location, prevalent winds, facilities hookup, local impact, etc.) and consequential result of failure may be different.

4.4.3 Quantitative and/or Qualitative Risk Assessment

4.4.3.1 The risk of a blowout is one of the major contributors to the overall risk associated with conventional drilling operations. Moves towards requirement for rig safety cases in many jurisdictions have placed increasing focus on risk and have resulted in greater attention to the validity of the statistical failure data used in quantitative risk analysis (QRA). In general, safety case documentation includes but is not limited to:

- an assessment of risk to people, assets and the environment, and
- identification of preventative and mitigating measures to ensure that risks are as low as is reasonably practicable (ALARP).

4.4.3.2 The determination of the risk level is based on a risk assessment matrix as shown in Figure 2. The matrix and the following explanation are included here for information only. Risks are deemed unacceptable in the boxes marked “Medium or High Risk.” If risks are identified within this sector of the matrix, then additional controls are required in order to shift the risk out of the sector. It is acceptable that such analysis is performed in a qualitative fashion based on reasoned judgment and expert opinion, other than where regulations may have specific requirements.

4.5 Project Approval

4.5.1 Project Plan

4.5.1.1 The overall project plan to undertake the UBD of a well should be signed by a qualified and corporately-authorized technical representative. That representative, by his/her signature, will be confirming that all the requirements of this document have been addressed in the plan and that the elements of the plan will be applied during the execution of the plan. The signature will also confirm that appropriate input from qualified technical experts has been obtained when required and that the qualifications of the technical experts are valid.


4.5.1.2 If the planned underbalanced well meets the definition of critical sour, the overall project plan shall be signed by a qualified and corporately authorized technical representative.

4.5.1.3 It is the operator’s responsibility to ensure that the required technical judgment has been used to develop the project plan and will be used during the execution of the project.

4.5.1.4 Competency assessment and training should be part of the plan.

4.5.2 Qualified Technical Expert

This document allows flexibility in practices provided a qualified technical expert relative to the practice/technology has approved the options in question. It is the operator’s responsibility to ensure that the expert is qualified as competent by normal industry standards.

RISK ASSESSMENT MATRIX		PROBABILITY OF OCCURRENCE (increasing probability) 				
POTENTIAL CONSEQUENCES		A	B	C	D	E
		Never heard of in the E & P industry	Has occurred in the E & P industry	Has occurred in the UBD industry	Likely to occur on this project	Likely to occur several times on this project
1	<ul style="list-style-type: none"> People: Slight Injury or health effects Asset: Slight property damage < \$10,000 USD Environment: Slight effect 	LOW RISK				
2	<ul style="list-style-type: none"> People: Minor Injury or health effects Asset: Minor property damage < \$100,000 USD Environment: Minor effect 					
3	<ul style="list-style-type: none"> People: Major Injury or health effects Asset: Localized damage < \$1,000,000 USD Environment: Localized effect (onsite) 	MEDIUM RISK				
4	<ul style="list-style-type: none"> People: Single Fatality or permanent total disability Asset: Major damage < \$10,000,000 USD Environment: Major effect (offsite) 					
5	<ul style="list-style-type: none"> People: Multiple fatalities Asset: Extensive damage > \$10,000,000 USD Environment: Massive effect 	HIGH RISK				

DEFINITION OF AN INCIDENT: "An incident is an unplanned event or chain of events which has caused or could have caused injury, illness to **People**, and or damage (loss) to **Assets**, **Environment**"

NOTE The values used in the matrix and the frequency are for example purposes only.

Figure 2—Hazard Matrix Chart

4.5.3 New Material, Equipment and Practices

Different materials, equipment and practices may replace those outlined in this document if the following items are addressed.

- They provide at least the same level of safety and public protection as those they are replacing.
- The appropriate technical experts have reviewed the design and that this review is included in the project documentation.
- In the case of a critical sour application or safety-critical equipment, there is some actual field performance history in similar use, e.g. on a non-critical sour production well or sour underbalanced drilled wells. The appropriate qualified technical experts shall review the performance data and this review is included in the project plan.
- The HAZOP review in 4.4.2 should specifically address in detail all potential impact of the replacements.

4.6 Emergency Response Plan (ERP)

4.6.1 A site-specific ERP for the UBD operation should be developed which addresses operating company policy and appropriate regulatory requirements.

4.6.2 The ERP should address both drilling and production operations. During conventional drilling operations, the ERP (in most jurisdictions where one is required by regulations) is implemented if there is a serious well control incident (total drilling fluid losses encountered or unplanned flow of formation fluids into the wellbore). During an underbalanced operation, there is continuous, planned, and controlled flow of formation fluids into the wellbore and the normal ERP implementation criterion does not apply.

4.6.3 The circumstances or events, which trigger implementation of the ERP plan shall be stated in the ERP.

4.6.4 For a critical sour UBD operation, a ERP for the EPZ shall be developed which addresses the appropriate regulatory requirements. In the absence of such regulations, the criteria as outlined in AEUB ID 90-1 should be referenced and followed as an industry best practice.

4.7 Underbalanced Drilling Operations Plan

A UBD operations plan should be developed and should address the following (see Figure 3).

- a) Appropriate regulatory requirements.
- b) Casing design.
- c) Casing wear—acceptance criteria.
- d) Completion design.
- e) Directional plan.
- f) Drill pipe safety valve operating practices. Especially, important consideration for drilling underbalanced with casing.
- g) Geological hazards.
- h) LWD operating practices.
- i) Drilling fluids program.
- j) Tripping operating practices.
- k) UBD BHA, drill pipe, NRVs, etc.
- l) Well control/kill operating practices.
- m) UBD surface equipment operating practices (vis-vis an open, partially open, or closed circulating system).

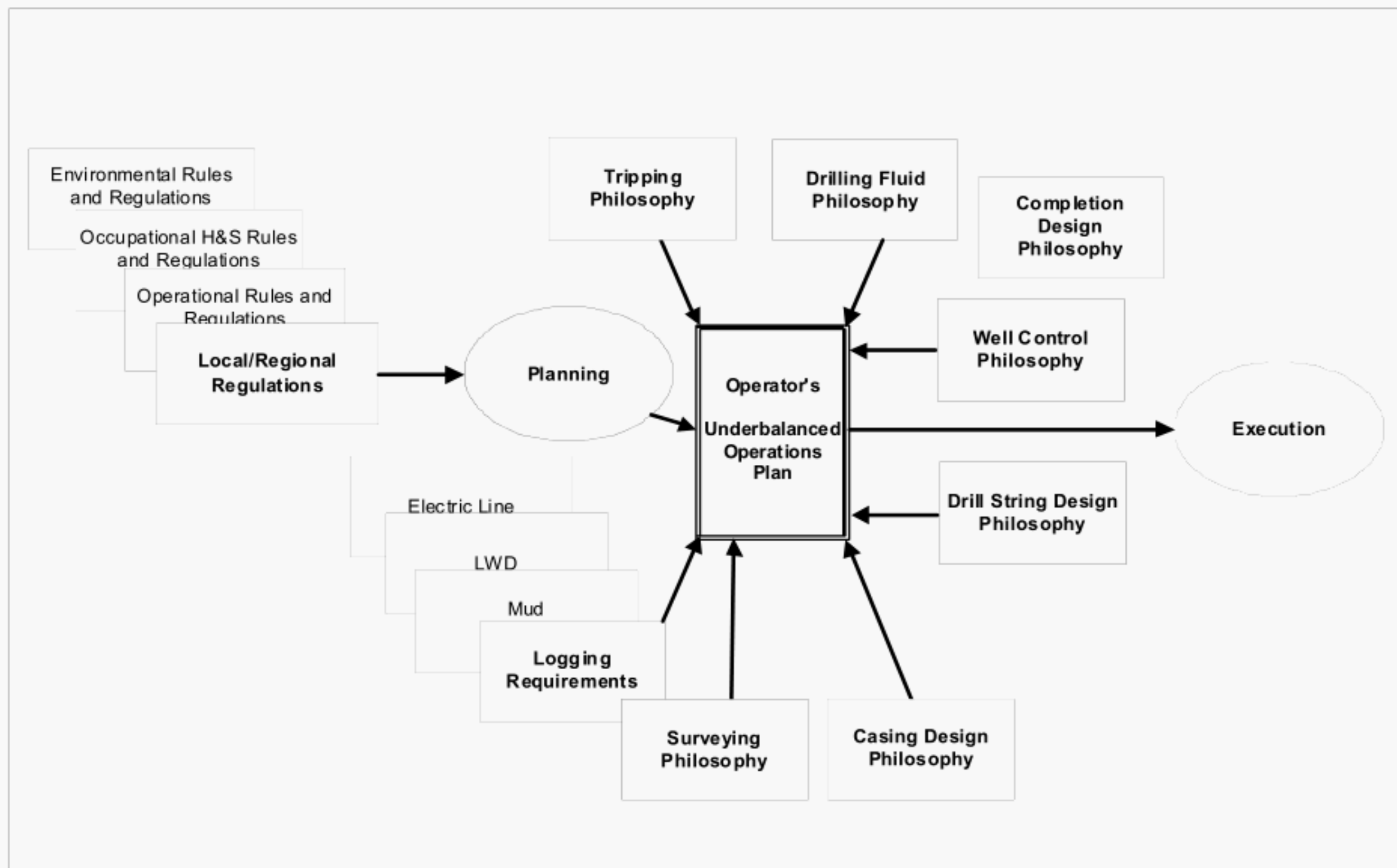


Figure 3—Planning Chart

5 Well Control

5.1 Scope

This section describes the principles, responsibilities and equipment necessary for maintaining appropriate well control during well control events. Control of the well during normal UBO is addressed in 6.2, which discusses surface return processing equipment.

5.2 Control Objective

5.2.1 The primary control objective of wells drilled overbalanced is to avoid formation influx. This goal is accomplished through surface management of drilling fluid densities. Hydrostatic fluid pressure is, therefore, the primary flow control barrier. BOPs and drill string float valves are installed, but should only be utilized if the primary control barrier fails.

5.2.2 In wells drilled underbalanced, the primary control objective is to maintain open hole wellbore pressures within the operating pressure envelope while safely processing formation influx in the return flow stream. Primary pressure control is jointly maintained by fluid density and surface back pressure exerted by the return flow processing equipment and drill string NRVs. BOPs shall be installed and utilized as secondary well control devices only if the primary control barriers fail.

5.2.3 Minimum surface equipment requirements shall be based on technical feasibility planning described in 4.2 and in 10.3 based on the IADC *Well Classification System for Underbalanced Operations and Managed Pressure Drilling* and referenced in 2.1.

5.3 Well Control Event Definition

5.3.1 Since underbalanced wells are designed to handle formation influx, the definition and response to a well control event is significantly different than overbalanced wells, which have very limited influx tolerances.

5.3.2 A well control event in a UBD operation occurs when the surface pressure, return flow rate, or wellhead temperature exceeds the upper limitations set by the design review as described in 4.4 for the surface equipment and displayed as the red zone in Table 1.

5.3.3 Underbalanced well control events can be caused by:

- higher formation pressure than expected;
- higher formation permeability resulting in higher flow rates than expected;
- failure or poor control of fluid injection and/or return processing equipment;
- unexpected difference in formation influx density resulting in higher surface pressures;
- drill pipe failure or leak, resulting in uncontrollable gas flow up drill string.

5.3.4 It is the operator's responsibility to have a plan in place to handle any well control incident.

5.4 Well Control Matrix

5.4.1 A well control matrix should be utilized to graphically illustrate and communicate to the UBO crews when action is required to return the well parameters of pressure and flow rate back into the optimum operating envelope. Furthermore it effectively highlights when secondary well control action is required. The matrix is for "bit on bottom" drilling parameters and excludes any other operations including, but not limited to, leak repairs, tripping, connections and circulating out of the hole.

An example matrix is shown in Table 1. The adjustment regions (usually shown in yellow) are established to allow safe reaction time to return operations to an optimum (green) condition. The areas labeled ">Max₃" (usually colored red) indicate well control events.

Table 1—Matrix of Well Control Actions

		Wellhead Flowing Pressure (unit)			
		Range 1 (Min ₁ - Max ₁)	Range 2 (Max ₁ - Max ₂)	Range 3 (Max ₂ - Max ₃)	> Max ₃
SURFACE FLOW RATES (unit/day)	Range 1 (0 - Max ₁)	Optimum	Adjust system to decrease WHP: · Increase liquid injection rate or · Decrease the gas injection rate	Pick-up off bottom, stop rotation: · Circulate with increasing liquid rate · Decrease the gas injection rate and · Monitor well parameters until stabilized	Shut-in well with BOP's
	Range 2 (Max ₁ - Max ₂)	Adjust system to increase BHP: · Increase liquid injection rate · Decrease the gas injection rate · Increase the surface back-pressure	Stop drilling, pick-up off bottom: · Circulate and work drill string · Increase liquid injection rate and · Decrease the gas injection rate	Pick-up off bottom, stop rotation: · Increase liquid injection rate and · Decrease the gas injection rate · Increase the surface back-pressure	Shut-in well with BOP's
	Range 3 (Max ₂ - Max ₃)	Stop drilling, pick-up off bottom: · Increase liquid injection rate and · Decrease the gas injection rate · Increase the surface back-pressure	Stop drilling, pick-up off bottom: · Circulate and work drill string and · Increase the surface back-pressure · Monitor well parameters until stabilized	Pick-up off bottom, stop rotation: · Circulate with higher density mud and adjust the gas injection rate · Monitor well parameters until stabilized	Shut-in well with BOP's
	> Max ₃	Shut-in well with BOP's	Shut-in well with BOP's	Shut-in well with BOP's	Shut-in well with BOP's

5.4.2 The well control matrix shall be project-specific and based on the design limitations of the actual equipment that will be used during project execution. A risk-based approach based on the following is recommended:

- a safety-factored maximum flow capacity (maximum transient gas/liquid rate) of the surface separation system;
- pressure rating on the UBD flow control equipment;
- erosion rates of the surface flowlines and manifolds (maximum drilling gas rate);
- maximization of the service interval for the CD;
- casing design limits—MASP as a function of the planned mud density, casing shoe depth and formation integrity test (if applicable).

The following are suggested well control matrix design parameters:

a) Wellhead flowing pressure:

- Range 1, Min_1 = minimum separator pressure to ensure effective dumping of fluids. Max_1 = 50 % of the RCD's dynamic rating;
- Range 2, Max_2 = the lesser of: the RCD's dynamic rating, 70 % of the UBD choke manifold's pressure rating and or the primary flowline's, maximum allowable working pressure;
- Range 3, Max_3 = the lesser of: 70 % of the RCD's static rating, the UBD choke manifold's pressure rating or the primary flowline's, maximum allowable working pressure.
- wellhead flowing pressure above Max_3 triggers a well control event.

b) Surface flow rates:

- Range 1, Max_1 = the lesser of the flowline erosion limit as a function of max allowable separator pressure or 60 % of the surface separation system's maximum flow rate (gas and/or liquid) capacity;
- Range 2, Max_2 = 75 % of the surface separation system's maximum flow rate (gas and/or liquid) capacity;
- Range 3, Max_3 = 90 % of the surface separation system's maximum flow rate (gas and/or liquid) capacity or the upper erosion limit of the surface flowlines and manifolds;
- surface flow rates above Max_3 triggers a well control event.

5.4.3 If the well is shut-in with the rig BOPs according to the well control matrix, subsequent operations will depend on whether the well can continue to be drilled in underbalanced mode.

5.4.4 The operator shall determine if the circulation system or drill string configuration can be modified to safely reduce the wellhead pressure or flow rates to manageable levels.

5.5 Kill Procedures

5.5.1 The well control and well kill procedures shall be established prior to the start of the UB operations.

5.5.2 In the event the well control event escalates to the point where it is necessary to kill the well, two methods are advised:

- if the problem is a surface equipment problem then a bullhead kill is advised;

— if the problem is subsurface related then the driller's method can be used to increase BHP.

5.5.3 Estimating Reservoir Pore Pressure—An Example Method

If multiphase fluids are produced while drilling, underbalanced BHP cannot be estimated using conventional well control method of shutting in the well and measuring drill pipe and casing pressures. Estimation of reservoir pore pressure shall be performed at the earliest possible time upon entering the reservoir and at regular intervals thereafter. As shown graphically in Figure 4, steady state flow measurements can be used to estimate BHP dynamically:

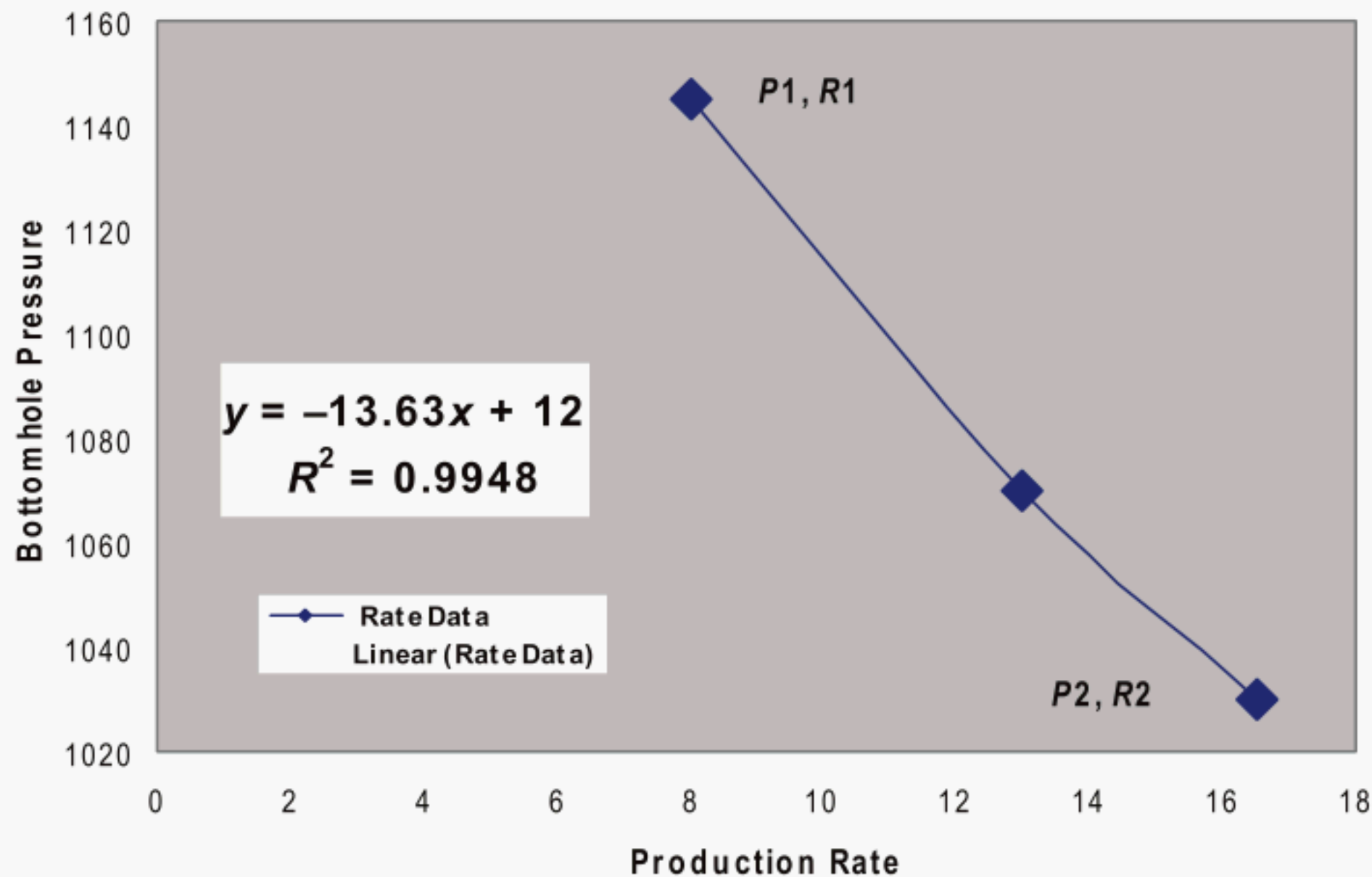


Figure 4—Bottomhole Pressure (BHP) Estimate Chart

$$\text{Reservoir Bore Pressure} = P1 + \frac{(P1 - P2)}{(R2 - R1)} R1$$

where

$P1$ is flowing BHP at Rate 1 ($R1$);

$P2$ is flowing BHP at Rate 2 ($R2$);

Rate1 is Production Rate 1;

Rate 2 is Production Rate 2.

In applying the above method to estimate reservoir pore pressure some caution should be exercised.

Typically, downhole pressure measurements are made close to the bit. In lengthy horizontal wellbores, there can be a significant difference in bottomhole circulating pressure at the bit (toe) and at the point of entry into the reservoir (heel). Any change in vertical depth along the exposed wellbore will also have an effect on the perceived reservoir pressure.

The method described above should be modified for horizontal wellbores by calculating a mid-point pressure between the bit and the heel of the well. Estimating the pressure drop across the horizontal wellbore and selecting the mid-point can accomplish this.

There can be a further dynamic effect as a result of near-wellbore depletion from producing the well while drilling and this needs to be considered.

5.6 Kill Weight Fluid

5.6.1 On wells classified as IADC Level 2, 3, 4 or 5, there shall be kill weight fluid of at least 1.5 times the hole-volume available on the wellsite during a UBD operation (see 8.3).

5.6.2 The kill fluid pumping system should be tied into the rig's kill manifold and maintained such that pumping can be started without delay, as and when required. The kill fluid holding and pumping system are critical components of the well control system and shall be included in well control inspection and testing programs.

5.7 Assignment of Duties

5.7.1 The operator should have a plan in place to control the well immediately in the event of an unplanned release of formation fluids.

5.7.1.1 In the event of an equipment malfunction, which impacts the pressure containment system integrity, the well shall immediately be shut-in. If the well cannot be shut-in, the kill fluid shall immediately be pumped into the wellbore.

5.7.1.2 If any event occurs causing an unplanned release of formation fluid, the well shall immediately be shut in. If the well cannot be shut-in, the kill fluid shall immediately be pumped into the wellbore preventing any further release. Hence any release should be of very short duration.

5.7.2 Individual duties of personnel engaged in UBO shall be clearly defined in the plan.

5.7.2.1 It is critical that the drilling contractor, the UBD service contractor and the operator's onsite representatives be involved in the creation of the plan.

5.7.2.2 The operator's onsite representative or the drilling contractor's senior representative shall have the authority to immediately execute this plan. To ensure understanding, these interfaces should be fully detailed in organization charts and communicated to all personnel during the onsite orientation briefing.

5.7.2.3 The need for effective liaison and meaningful communications between the operator's representative, the drilling contractor's onsite management [offshore installation manager (OIM), toolpusher etc.], is a high priority.

5.8 BOP and Wellhead Equipment

5.8.1 Safety and Environmental Considerations

5.8.1.1 The safety of the onsite personnel and the public at large within the EPZ is the most important factor in the stack design.

5.8.1.2 During underbalanced well operations, the BOP stack will be continuously exposed to wellbore effluent and pressures.

5.8.2 Functional Requirements

5.8.2.1 In selection of preferred BOP stack arrangements and equipment, it is necessary to accept the fact that equipment can fail during drilling, stripping, snubbing or pressure deployment operations. Therefore, redundancy in the system is necessary to reduce the effect of a failure.

Minimum BOP equipment required for secondary well control shall not be compromised by laying down BOP equipment in order to fit a RCD.

5.8.2.2 The amount and type of equipment needed is affected by the magnitude of the surface pressures expected, the method of pipe rotation (top drive or rotary kelly), the nature of the reservoir fluids to be encountered (sour gas and/or oil), and the type of drilling fluid system. Taking these factors into consideration, UBD requires a BOP system which:

- provides for backup annulus control in event of primary well control equipment failure;
- provides a means to quickly and safely shut-in the well;
- includes a system for bleeding off and equalizing pressure between the rams and below the primary control equipment.

5.8.2.3 Installation, maintenance, function testing and pressure testing of the rig's well control choke manifold, choke and kill lines, valves, fittings and other components, including the accumulator system and BOP components used in a UBD operation, should be in accordance with API 53.

5.8.3 Design Requirements

5.8.3.1 BOP equipment used in a UBO application shall be manufactured, installed and tested in accordance with appropriate API/ISO standards (including this document) and applicable regulatory requirements.

5.8.3.2 The casing, wellhead and BOP stack shall be able to accommodate all forces it could be subjected to during the course of underbalanced operations, including axial and lateral loads imparted by the drill string, and weight of the stack.

5.8.3.3 The annular BOP should be capable of closing and sealing when exposed to wellbore pressure from above the annular.

The flowline ESD valve is actuated trapping pressure above the annular BOP. This may render the annular BOP inoperable. Depending on the position of tool joints, or other odd-sized drill string components relative to the pipe rams, this situation may negatively impact the functionality of the BOPs.

5.8.3.4 Equipment shall be in place to isolate the UBO equipment from wellbore energy and as a barrier to apply additional pressure if needed for pressure testing purposes for the following conditions:

- after installing a new bearing and/or packing element and prior to resuming operations of the RCD, pressure testing is required to re-qualify the RCD as a barrier;
- after installing new elements on the rams or other working barriers in, e.g. the snubbing stack, pressure testing is required to re-qualify them as working barriers prior to resuming operations.

5.8.4 Shear Ram Cutoff Test

5.8.4.1 Certified documented evidence shall be required to assure that the shear ram system to be used on a critical sour UBD operation has been tested on the size and grade of pipe in use. In the absence of documented evidence, a shear ram cutoff test shall be conducted on the BOP stack immediately prior to being put into service.

5.8.4.2 In the event that CT is the drill string, the test shall be conducted with the coiled tubing BOP stack pressured up to its maximum operating pressure and a representative sample of coiled tubing, including telemetry cable if applicable, shall be sheared. The shear rams should be visually inspected after the test and prior to being put into service.

5.8.5 Stack Configurations

5.8.5.1 Sweet and Non-critical Sour Wells

The configuration required will depend on the applicable regulatory requirements and/or company requirements but under no circumstances should it be less than what is recommended based on the IADC Classification Level for the well to be drilled underbalanced (see 10.3).

5.8.5.2 Critical Sour Wells

5.8.5.3 All BOP stack configurations shall include shear or shear/blind rams. The shear blades shall be capable of shearing the tube in the sour environment. If shearing of BHA components is not possible, a downhole isolation device shall be required on critical sour UBD operations.

5.8.5.3.1 Empirical data supporting the reliability of the blades for service in the sour environment is required.

5.8.5.3.2 The stack configuration shall include two lines of defense, and a monitoring system to indicate when the primary line of defense has failed.

5.8.5.3.3 Consideration should be given to using a tubing spool below the stack to allow the landing of a tubing hanger.

5.8.5.3.4 Consideration should also be given to using a full opening gate valve below the stack. This would provide additional flexibility in pressure testing and will allow the well to be shut-in independently of the BOPs.

5.8.5.4 Example stack configurations are illustrated in:

- Figure A.2, Figure A.3 and Figure A.4, for jointed pipe operations;
- Figure A.5 for CT operations.

Design and arrangement of the BOP stack equipment is generally covered by applicable regulations and/or company policy. However, the final stack design should be based on a proper risk assessment related to the project-specific hazards and the stack design should be closed out during the HAZOP review discussed in 4.4.2.

5.9 Internal Drill String Equipment

5.9.1 Jointed Drill Pipe

5.9.1.1 The drill string shall be equipped with a minimum of one primary and one redundant NRV before it can be deployed into or out of the well.

5.9.1.2 In a sour UBD operation, provisions should be made in the drill string so additional pressure control devices can be added while the drill string is in the well. If the pressure control devices in the drill string are known to have failed during operations in the well, an additional pressure CD should be installed in the drill string before it is pulled from the well.

5.9.2 Coiled Tubing Drill String

The CT drill string shall be equipped with a double check valve in the BHA.

5.9.3 Drill Pipe Safety Valve (Stabbing Valve)

5.9.3.1 Installation, maintenance, function testing and pressure testing of the drill pipe safety valve shall be in accordance with API 53.

5.9.3.2 The drill pipe safety valve shall have a pressure rating equal to or greater than the BOP pressure rating and should be equipped to screw into any drill string element in use.

5.9.3.3 An assessment should be made between optimum ID and OD of DP safety valve with regard to manual handling, wireline restrictions, etc.

5.9.3.3.1 Typically, the ID should match the plugs that may have to be run to enable pressure control devices to be lubricated into the hole on wireline under pressure through the drill pipe safety valve. This is especially critical in a sour UBD operation.

5.9.3.3.2 The outside diameter of the drill pipe safety valve should be sized to be no larger than the tool joint OD to facilitate stripping into the well.

NOTE It is desirable that the OD of the valve be such that it may be stripped in through the RCD and/or the annular BOP. This may not always be possible since on a sour well the valve must also be manufactured of metallic materials meeting the requirements of NACE MR 0175. The issue of drill pipe safety valves should be addressed in the drilling plan when drilling with casing in an underbalanced mode.

6 Return Flow Process Control Equipment

6.1 Scope

UBD systems are composed of the following subsystems:

- fluid injection equipment;
- drilling fluid media;
- drill string and bit;
- return flow process control equipment.

This section describes the return flow process control equipment exposed to solids-contaminated hydrocarbon effluent flow and erosional velocities during UBD operations:

- Section 7 describes drill string considerations;
- Section 8 describes UBD fluids.

6.2 Return Flow Process Control System Requirements

6.2.1 Safety and Environmental Considerations

6.2.1.1 The safety of the onsite personnel is the most important factor in the UBD flow control system design.

6.2.1.2 In selection and design of UBD flow-control equipment it is necessary to accept the fact that equipment can fail during the operation. Experience has shown that the RCD and the UBD choke are components of the system most likely to fail due to operational wear and tear. Therefore, planned monitoring, preventative maintenance and some redundancy is necessary to prevent failure.

6.2.2 General Considerations

6.2.2.1 Although the return flow processing system, including the RCD, fulfills primary well control functionality in a UBD operation, the RCD is not a BOP. However, it is the first line of defense between the well effluent and the onsite personnel. This is a key distinction in a sour UBD operation.

6.2.2.2 Return flow process control equipment requirements and configurations are based on the characteristics of each well, such as depth, hole size, anticipated volume of produced fluid, amount of solids anticipated, the nature of the reservoir fluids to be encountered (sour gas and/or oil), maximum pressures, the method of pipe rotation (top drive or rotary table) and the type of drilling fluid system. UBD requires a flow-control system which:

- permits drilling to proceed while controlling annular pressure;
- allows connections to be made either with the well flowing or shut-in;
- allows tripping of the drill string under pressure to change bits or BHAs.

6.2.2.3 The return flow processing system capacity should be based on the maximum potential production at maximum drawdown.

6.2.2.4 Short-term near-wellbore flush production can result in a flow rate that can significantly exceed expected rates. If the well to be drilled is in an area with little production experience, or is a significant step-out location, the fluids handling system should be designed and selected to provide for adequate capacity.

6.2.2.5 The failure potential is not the same for all components of the UBD operation. On the high-pressure side of the UBD choke manifold, the RCD is exposed to wear and tear from drill pipe movement during the operation and from potential misalignment between the derrick and the BOP stack. In addition, the RCD and the BOP stack is highly stressed, and therefore prone to sulfide stress corrosion cracking (SSCC) in a sour environment. Conversely, the equipment downstream of the choke manifold operates at lower pressure and therefore a lower risk of SSCC, but a potentially much greater risk of failure due to erosion. The consequences of an equipment failure also vary depending upon the particular service. The failure of the BOP stack components, e.g. is considered more serious than the failure of a manifold or degasser component since the ability to contain hydrocarbon effluent within the wellbore would be lost in the former situation. The resulting combination of high risk and consequence of failure of components, such as the RCD and BOP stack, warrants the highest degree of material control relative to other drilling equipment.

6.2.2.6 Elastomer technology continues to evolve, and consultation with the original supplier as to the most suitable elastomers is recommended. Elastomers tend to be less tolerant than metallic materials due to the wide range of drilling environments encountered; therefore, detailed fluid properties and the range of operating conditions expected should be addressed in the selection process.

6.2.3 Process Safeguarding

6.2.3.1 Safeguards and isolation actions should be in place to prevent escalation of abnormal conditions into a major hazardous event and to limit the duration of any such events.

6.2.3.2 The process safeguarding system shall meet the requirements of the HSE case when one is required.

6.2.3.3 The safeguarding system should prevent the process from operating outside of the design envelope.

6.2.3.4 The safeguarding system should be separate from the control system.

6.2.3.5 To ensure a high degree of reliability, provisions should be made to allow for regular testing.

6.2.3.6 Where possible, primary and secondary safeguards should use diversity (e.g. different types and makes of equipment, measurement of different process parameters) to minimize the risk of common-cause failures.

6.2.4 Underbalanced Drilling Control Device (UBD-CD)

6.2.4.1 The static pressure rating of the UBD-CD should be equal to or greater than the MASP.

If this is not the case (regardless of the reason), the well shall be classified as an IADC Level 5 UBD well and appropriate emergency shutdown procedures shall be prepared and communicated to operations personnel.

6.2.5 Critical Sour Wells

6.2.5.1 Two UBD-CDs shall be installed above the BOP stack and during any underbalanced operation both UBD-CDs shall be closed.

6.2.5.1.1 The lower barrier is considered the primary barrier.

6.2.5.1.2 The top UBD-CD is in place to provide a second line of defense to the personnel working on the floor. This is a precautionary measure since personnel are working on the floor above the stack (as compared to a CT operation where personnel are not required to work around the wellhead during the underbalanced operation).

6.2.5.2 RCDs with integral dual sealing elements fulfill this requirement.

6.2.5.3 Both UBD-CDs should have the same static pressure rating.

6.2.5.4 The dynamic pressure rating of the upper UBD-CD is not required to be the same as the lower. However, should the lower barrier be lost then the focus of operations shall be to repair the primary barrier to restore the two barrier status.

6.2.5.5 A monitoring system shall be installed between the two UBD-CDs to monitor for failure of the primary UBD-CD.

6.2.5.6 The operation shall be stopped if a failure of either UBD-CD occurs, and the failed UBD-CD shall be repaired before operations proceed. The capability shall be in place to allow the replacement of both UBD-CD elements with the drill string in the well.

6.2.6 Emergency Shutdown (ESD) Valve

6.2.6.1 ESD Valve Compared to BOPs

The ESD valve, when required, shall be a fail-closed valve.

- To reduce the potential for over-pressuring wellhead equipment, the shoe, etc. upon activation of ESD valve, immediate shut down of the pumps is required, either automatically or procedurally.

The primary functions of an ESD valve on the return-flowline of the UBD return flow control system are prevention of incident escalation and protection of personnel and equipment. This must be evaluated relative to increased risk from an accidental ESD valve closure.

- First, to be effective it can be activated to quickly shut in and isolate the well in the event of a surface leak downstream of the RCD. Flowline pressure sensors, the ESD system, fire loop system and sensors on downstream process components should actuate the ESD valve.

- Secondly, to be effective it can be designed to automatically shut in and isolate the well in the event of a washed out choke in a UBD system by detecting different pressure ratings upstream and downstream of the choke through the use of process logic controllers (PLC).
- Lastly, to be effective it can be tied in to a visual and audible alarm to alert rig personnel to a potential well control incident.

In UBD operations, these functions are adequately covered, with multiple redundancies, by the rig's BOPs. However, timing drives the requirement for an ESD valve in the return flow process control system as follows:

- consider the time it takes for the driller to be notified of the condition and to activate the BOP and then the time it takes for the physical closure of the BOP;
- although speed of closure does not improve the functionality of the ESD valve, the speed of closure reduces the exposure to the potential hazard.

6.2.6.2 Recommendations for ESD

API 14C provides excellent guidance and a structured analysis and design methodology to systematically assess the requirements for surface safety systems including ESD valves. The key components of this methodology are:

- safety analysis tables (SAT);
- safety analysis checklists (SAC);
- safety analysis function evaluation (SAFE) chart.

It is recommended that the methodology contained in API 14C be employed to evaluate the need and placement of ESD valves for UBD operations.

6.2.6.3 Requirement for ESD Valves

Table 2 outlines the requirements for ESD valves and whether a full SAT/SAC/SAFE analysis is required (as per API 14C).

6.2.6.4 Exemption Requirements

Wells may be exempted from the requirement for an ESD valve if an engineering review based upon API 14C (SAT/SAC/SAFE as described earlier) and other relevant information shows that this is acceptable. This shall be reviewed within the context of the ESD philosophy. Examples of possible exemption justifications include the following.

- If the reaction time and closure time of the BOP is less than the time it takes for the process vessels to fill up and an overpressure condition to occur, the use of the BOP to replace the functionality of an ESD valve may be considered. For example on a land operation where the process is manually monitored and operated and the large, horizontal, high-volume, four-phase separators are used for UBD operations on low volume oil and, in some cases, low volume gas wells.
- If the separator is rated for MASP.
- If the operation is planned to use incompressible fluids within the well bore.
- If it can be demonstrated that the activation of the ESD is likely to result in a higher risk of overpressure at the RCD or BOP.

Table 2—ESD Logic Chart

IADC Level	Definition	ESD Valve Required?	Exemption Possible?	SAT/SAC/SAFE Required?
0	Performance enhancement only; no zones containing hydrocarbons.	No	N/A	No
1	Well incapable of natural flow to surface. Well is “inherently stable” and is a low-level risk from a well control point-of-view.	No	N/A	No
2	Well capable of natural flow to surface, but conventional well kill methods are enabled and limited consequences are possible in case of catastrophic equipment failure.	Yes	Yes ^a	Yes ^a
3	Geothermal and non-hydrocarbon production. Maximum shut-in pressures are less than UBD equipment's operating pressure rating. Catastrophic failure has immediate, serious consequences.	Yes	No	Yes
4	Hydrocarbon production. Maximum shut-in pressures are less than UBD equipment's operating pressure rating. Catastrophic failure has immediate, serious consequences.	Yes	No	Yes
5	Maximum anticipated surface pressures exceed UBO equipment's operating pressure rating, but are below BOP stack rating. Catastrophic failure has immediate, serious consequences.	Yes	No	Yes
^a See 6.2.5.4 for exemption requirements.				

6.2.6.5 ESD Valve Specifications

ESD valve shall have the following specifications.

6.2.6.5.1 Maximum Allowable Working Pressure (MAWP)

For IADC Level 2 to 4 Wells, $MAWP_{ESD} > MASP$

For IADC Level 5 Wells ($MAWP_{RCD} > MASP$), *then* $MAWP_{ESD} = MAWP_{RCD}$

6.2.6.5.2 Location of the Valve

As per API 14C, the ESD valve should be located on the wellhead/BOPs as the 1st or 2nd valve in the flow stream from the wellbore. In IADC Level 2 wells, it is acceptable to locate the valve near the choke manifold to simplify rig-up time. In wells with erosion concerns, this practice should be avoided.

6.2.6.5.3 Remote Operation

The ESD valve shall be operated at all times by ESD system and/or manual push buttons, etc. as defined by the SAFE Chart.

6.2.6.5.4 Solids Build Up

To reduce the possibility of solids build-up preventing the valve from closing, only valves that close and seal in the up direction should be used in a UBD operation.

6.2.6.5.5 Locked Open Position

The ESD valve shall not be operated in a locked open position.

6.2.6.5.6 Valve Position Indicator

A valve position indicator is recommended, equipped with a visual and audible alarm system to be actuated when the ESD valve is in the closed position.

6.2.6.6 Precautions on IADC Level 5 Wells

When used on IADC Level 5 wells, closure of the ESD valve could result in excessive pressure on the upstream UBD-CD. In this situation, a means of alleviating pressure before this condition occurs should be implemented. Possible solutions are as follows.

- Closing of the BOP upon activation of ESD valve closure either automatically or manually.
- Opening of a secondary flowline using a rupture disk or automatically-operated valve. The risk of an incident escalation should be considered.

6.2.7 Temporary Piping—General

6.2.7.1 Temporary piping in an underbalanced operation consists of the conduits for directing fluids from a high-pressure source (e.g. the wellhead or christmas tree) to a lower pressure source (e.g. the flare stack) or fluids directed to outlets ending with plugs on which sensors are mounted. Temporary piping include the conduits required for transfer of fluids between vessels and or tanks.

6.2.7.2 “Piping” and “temporary piping” have the same meaning when used in these recommended practices.

6.2.7.3 Piping can be either stiff or flexible and includes, but is not limited to, the following:

- swivel-joint pipe;
- pipe with hammer-union type connections;
- pipe with hub-type end connections;
- high-pressure flexible hoses;
- flanged pipe runs.

6.2.7.4 Personnel with responsibilities for the various aspects of piping installation and operations shall be determined to be competent to carryout those responsibilities.

6.2.7.5 Connection of temporary flowlines with hammer-union type connections having the same size, but different pressure ratings (“Figure Numbers”) have led to serious incidents in the oil and gas industry. Review and verification of the process design for the temporary flowlines is required. Equipment interfaces, installation of the temporary flowlines, commissioning and testing prior to use, monitoring and servicing while in operation and de-commissioning should be discussed during the HAZOP review discussed in 4.4.2.

6.2.7.6 The use of hammer-union type connections of size 2 in., Figure Number 602 for pipe runs or individual male or female connections used as plugs or for adapting to instrumentation fittings should be avoided.

6.2.7.7 The following Hammer-union type connection mismatches are possible and shall be avoided.

Table 3—Mismatching Figure Numbers

Size	Union Figure Numbers	
1 1/2 in. (38.1 mm)	600, 602, 1002	Union Integrity compromised by depth of thread engagement between nut thread with female union sub-threads have same pitch.
2 in. (50.8 mm)	602, 1502	
5 in. (127 mm)	400, 1002	

6.2.7.8 Connecting pipe having different pressure ratings but with end connections of the same size and Figure Number shall be avoided.

Table 4—Mismatching Pressure Ratings

Figure Numbers	Pressure Rating Mismatch Caused by
All pressure ratings up to Figure 1502 Hammer-unions	Mixing sour-gas pipe with standard service pipe.
All Figure Numbers	Mixing unions attached to the pipe by pipe threads with those unions welded to the pipe.

6.2.7.9 Interconnecting piping having hammer-union type wing nut of one size and Figure Number mounted on the male sub of another size and figure number shall be avoided. If a mismatch in piping exists, use a proper crossover. Refer to Table 3.

Table 5—Mismatched Wing Nuts

Figure Numbers	Pressure Rating Mismatch Caused by
All Figure Numbers where the wing nut fits over the male sub. (e.g. a 2-in. Figure 602 standard male sub with a 2-in. Figure 1502 wing nut.)	Small amount of engagement of the male sub in the wing nut.

6.2.7.10 Interconnecting piping having segments and nut of one Figure Number made up to the detachable male sub with a different figure number shall be avoided.

Table 6—Mismatched Components

Figure Numbers	Pressure Rating Mismatch Caused by
All Figure Numbers where the wing nut fits over the male sub (e.g. 2-in. 602 detachable male sub with 2-in. 1502 wing nut).	Small amount of engagement of the male sub with the segment engaging the wing nut.

6.2.7.11 Mismatching of non-detachable and detachable piping components is possible. Therefore, assembly of non-detachable nuts on detachable male subs shall be avoided.

Table 7—Mismatched Detachable and Non-detachable Components

Size	Union Figure Numbers	Union Pressure Integrity Compromised by
2 in.	602, 1002	The detachable wing nuts require a longer thread length to compensate for the segments between the wing nut and the sub shoulder. Use of a non-detachable wing nut in a detachable Union results in lack of thread engagement.
3 in.	602, 1002	Mounting of non-detachable wing nuts onto a detachable male sub end results in insufficient engagement between the male sub shoulder with the wing nut ID.

6.2.8 Design and Manufacture of Temporary Piping

6.2.8.1 Temporary piping shall be designed to industry standards, e.g.:

- ASME Section VIII, Division 2 for determining the allowable stresses;
- ASME/ANSI B1.5 or B1.8 for the thread profiles;
- ASME B31.3 up to and including 5000 psi;
- API 6A or API 6C for over 5000 psi.

6.2.8.2 Temporary piping shall be certified by an independent competent body, the certification stipulating:

- product/equipment description (including the restraining system where considered as part of the design);
- application and limitations;
- documents reviewed for the certification (drawings, calculations, material specifications);
- fabrication procedures, comprising test procedures, non-destructive examination procedures, quality control procedures;
- equipment marking;
- documentation to be supplied.

6.2.8.3 The piping design shall incorporate a suitable means of restraint.

6.2.9 Piping Component Traceability

6.2.9.1 Each temporary piping component shall be indelibly marked with its class and unique identifier traceable to its manufacture.

6.2.9.2 Piping component identification, including markings on blind runs, pipe extensions made up to vessel outlets for the purpose of mounting instrumentation, plugs on vessel outlets, unused inlets, etc., shall be clearly visible to persons tasked with “walking the lines” verifying that the layout reflects the PFD.

6.2.9.3 Reliance on color coding alone for identification should be avoided.

6.2.10 Installation of Temporary Piping at the Well Site

6.2.10.1 Prior to pressure test, the piping shall be checked to confirm that the work complies with the P&ID or PFD. Instrument set points, relief calibration, and correct installation of the piping tie down system shall also be verified during these checks.

6.2.10.2 Piping connections requiring specified torque or bolt tension shall be undertaken using accurately calibrated torque wrenches. The make-up of these connections should be witnessed.

6.2.10.3 All sections of a temporary piping system shall be installed so as not to impinge on fittings, valves, instrumentation or other protuberances, and shall be suitably restrained to prevent uncontrolled movement in the event of severe vibration or connection failure.

Restraint shall take the form of a clamping arrangement on each section of pipe. The clamps shall be connected either to suitable structural anchor points along the length of the pipe run or to a suitable cable run between connection points.

6.2.11 Main Flowline

6.2.11.1 The main flowline upstream of the choke manifold should be as straight as possible to minimize friction and erosion.

6.2.11.2 Uniform piping inside diameter should be maintained to minimize turbulence within the flowline. Butt-weld unions and flanges also help to minimize turbulence.

6.2.11.2.1 To minimize erosion, the main flowline components between the flow diverter and the separator, with the exception of the choke manifold, should avoid having diminishing internal diameter.

6.2.11.2.2 The inside diameter of the piping downstream of the choke manifold should be larger than the upstream piping.

6.2.11.3 Appropriate ports for chemical injection should be installed. Consideration should be given to the installation of a secondary flowline connected to the choke manifold and separator.

6.2.11.4 Pressure Rating

The main flowline upstream of the first control valve should have a working pressure rating equal to or greater than the MASP.

6.2.11.5 End Connections

The main flowline upstream of the first control valve should have flanged, welded or clamped integral-type end connections.

6.2.11.6 Erosion Calculations

6.2.11.6.1 Erosion calculations are required to determine proper flowline sizing, taking into account abrasion, corrosion and slug flow which can lead to line jacking).

6.2.11.6.2 *Reference.* API 14E has a calculation method to estimate the erosional velocities of multiphase fluids containing sand.

There are other calculation methods such as Salama & Venkatesh, Tulsa and RCS with different calculation methods. However, the API method is significantly lower in its erosion estimates than the Tulsa or Salama & Venkatesh methods.

6.2.11.7 Inspection and Certification

6.2.11.7.1 Pre-job inspection should include verification of current certification (according to supplier's written

and records of the inspection should be retained at the wellsite. The inspection frequency shall be increased if wear becomes noticeable. High rate gas wells shall be monitored real time.

6.2.11.8.2 The intent of this inspection is to ensure that wear spots are identified prior to pipe failure.

6.2.11.9 On-site pressure testing shall be conducted per 10.6.

6.2.12 UBD Choke Manifold

6.2.12.1 On some wells classified as IADC Level 1 and Level 2, the use of separator backpressure may suffice to control flow from the well without an inline choke. However, this should be addressed and closed out during the HAZOP review discussed in 4.4.2.

6.2.12.2 While the use of either a choke or the separator backpressure may be appropriate for IADC Level 1 or Level 2 wells, on Level 3, Level 4 and Level 5 wells both are required.

6.2.12.3 With the exception of a well classified as IADC Level 5, the choke manifold shall have a pressure rating equal to or greater than the MASP, and should include two chokes and isolation valves for each choke and flow path.

6.2.13 Downstream Inlet Piping

6.2.13.1 All piping downstream of the choke manifold and up to and including the separator inlet shall have a working pressure equal to or greater than the maximum operating pressure of the separator.

6.2.13.2 All piping downstream of the choke manifold and up to and including the separator inlet should have flanged, welded or clamped integral-type end connections.

6.2.14 Standpipe Bleed-off Line

6.2.14.1 The standpipe bleed-off line shall be tied into the standpipe injection header to provide a safe means of bleeding down the standpipe to the separation equipment (e.g. to bleed off before a drill pipe connection when injecting gaseous fluids down the drill pipe). A check valve should be installed in this line.

6.2.14.1.1 The standpipe bleed-off line must be set up to bleed off pressure to atmospheric pressure, prior to making a connection.

6.2.14.1.2 Tie-in of bleed-off lines should be assessed on the basis of the surface equipment set-up. The bleed-off may be tied into separation equipment and the atmospheric degasser. When the bleed-off line is tied into pressurized process equipment, a check valve upstream of the equipment is recommended. To prevent overpressure to the atmospheric degasser an orifice choke should be installed upstream of the degasser unit.

6.2.14.1.3 At high pressures, a two-stage process can be used. First, by bleeding off to separator pressure and second to atmosphere via the degasser.

6.2.14.1.4 At low pressures, bleed off pressure to the degasser or to flare.

6.2.15 Separator

6.2.15.1 Certification

The appropriate regulatory bodies supporting compliance to pressure vessel and electrical standards shall certify the UBD separator and the skid unit.

In the absence of applicable regulatory bodies supporting compliance to pressure vessel and electrical standards, certification by an industry recognized certifying authority shall be available on site.

In the absence of applicable pressure vessel and electrical standards, other nationally or internationally recognized standards shall be used as the basis for certification.

Up-to-date documentation should be available at the wellsite that verifies the function testing of the pressure relief valves. Assurance of correct sizing of the pressure relief valves shall be supported with gas flow calculations available at the wellsite.

6.2.15.2 The separator equipment capacity should be determined by considering the hole size, depth, reservoir pressure, anticipated flow rates, H₂S concentration and expected solids recovery (see 4.2.2).

6.2.15.3 The separator equipment capacity should be based upon maximum potential production at maximum drawdown (in a prolific gas reservoir this may not be possible, therefore an adequate manifold system for holding back-pressure would be mandatory).

6.2.15.4 Separator equipment used in a UBO that includes the use of air as the injected lift gas shall be of the non-pressurized atmospheric type.

6.2.15.5 For the drilling of a gas reservoir where the potential exists for production rates higher than the capacity of the separator vessel (based on an atmospheric design) and/or at a flowing wellhead pressure that is high relative to the separator design, it is recommended that a pressurized separator be considered.

Alternatively, a second choke manifold may be considered to step down any large surface circulating pressures (instead of using one manifold and taking the entire pressure drop across a single system), and/or chokes, which are highly erosion resistant may be used.

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6.2.16.2 Pump line equipment should include one check valve installed between the pump and standpipe, and have a working pressure equal to or greater than the MASP.

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6.3.1 Working Pressure

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All pressure containing connections should have metal-to-metal seals or, if hammer-union type connections are used, the threads shall be isolated from the well bore environment by appropriate seals and the end connections shall be welded to the pipe. Hammer-union type connections shall not be used on equipment in diameters greater than 4 in.

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6.2.16.2 Pump line equipment should include one check valve installed between the pump and standpipe, and have a working pressure equal to or greater than the MASP.

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6.3.1 Working Pressure

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All pressure containing connections should have metal-to-metal seals or, if hammer-union type connections are used, the threads shall be isolated from the well bore environment by appropriate seals and the end connections shall be welded to the pipe. Hammer-union type connections shall not be used on equipment in diameters greater than 4 in.

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6.2.16.2 Pump line equipment should include one check valve installed between the pump and standpipe, and have a working pressure equal to or greater than the MASP.

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6.3.1 Working Pressure

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All pressure containing connections should have metal-to-metal seals or, if hammer-union type connections are used, the threads shall be isolated from the well bore environment by appropriate seals and the end connections shall be welded to the pipe. Hammer-union type connections shall not be used on equipment in diameters greater than 4 in.

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The rationale for these recommendations is to minimize the degree of pressure drop across one restriction, thereby minimizing erosion. In an oil well these steps may not be warranted if the anticipated BHPs would not cause high flowing wellhead pressures. In this event, a choke manifold see 6.2.13 and separation vessel should be used.

6.2.16 Pump Lines and Equipment

6.2.16.1 Pump lines and related components used for pumping fluid down the drill pipe shall have a working pressure equal to or greater than the MASP. Elastomers shall be compatible with the fluid circulating medium and the service conditions.

6.2.16.2 Pump line equipment should include one check valve installed between the pump and standpipe, and have a working pressure equal to or greater than the MASP.

6.3 Equipment Specifications

6.3.1 Working Pressure

All pressure containing equipment, including equalizing loops and bleed-off lines, shall have a working pressure equal to or greater than the maximum pressure testing requirement for the secondary well control equipment.

6.3.2 Connections

All pressure containing connections should have metal-to-metal seals or, if hammer-union type connections are used, the threads shall be isolated from the well bore environment by appropriate seals and the end connections shall be welded to the pipe. Hammer-union type connections shall not be used on equipment in diameters greater than 4 in.

In the absence of applicable regulatory bodies supporting compliance to pressure vessel and electrical standards, certification by an industry recognized certifying authority shall be available on site.

In the absence of applicable pressure vessel and electrical standards, other nationally or internationally recognized standards shall be used as the basis for certification.

Up-to-date documentation should be available at the wellsite that verifies the function testing of the pressure relief valves. Assurance of correct sizing of the pressure relief valves shall be supported with gas flow calculations available at the wellsite.

6.2.15.2 The separator equipment capacity should be determined by considering the hole size, depth, reservoir pressure, anticipated flow rates, H₂S concentration and expected solids recovery (see 4.2.2).

6.2.15.3 The separator equipment capacity should be based upon maximum potential production at maximum drawdown (in a prolific gas reservoir this may not be possible, therefore an adequate manifold system for holding back-pressure would be mandatory).

6.2.15.4 Separator equipment used in a UBO that includes the use of air as the injected lift gas shall be of the non-pressurized atmospheric type.

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