Underbalanced Drilling Operations

API RECOMMENDED PRACTICE 92U
FIRST EDITION, NOVEMBER 2008

Underbalanced Drilling Operations

Upstream Segment

API RECOMMENDED PRACTICE 92U
FIRST EDITION, NOVEMBER 2008

Special Notes

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

Users of this recommended practice should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

API publications may be used by anyone desiring to do so. Every effort has been made by API to assure the accuracy and reliability of data contained in this publication. However, the Institute makes no representation, warranty, or guarantee in connection with publication of these recommended practices and hereby expressly disclaims any liability or responsibility for loss or damage resulting from use or applications hereunder or for violation of any federal, state, or local regulations with which the contents may conflict. Users of recommendations set forth herein are reminded that constantly developing technology and specialized or limited operations do not permit complete coverage of all operations and alternatives. Recommendations presented herein are not intended to inhibit developing technology and equipment improvements or improved operating procedures. These recommended practices are not intended to obviate the need for qualified engineering and operations analyses and sound judgments as to when and where these recommended practices should be utilized to fit a specific underbalanced drilling application.

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.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

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.

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 1220 L Street, N.W., Washington, D.C. 20005.

Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, D.C. 20005, standards@api.org.

Contents

Page

Figures

Tables

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 1 [6], *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 97/0236 [7], *Underbalanced Drilling Manual*

IADC [8], *Well Classification System for Underbalanced Operations and Managed Pressure Drilling*

NACE MR 0175 [9], *Petroleum and Natural Gas Industries Materials for Use in H_2S-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 11 [10]

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:

API gravity (degrees) = (141.5/specific gravity 60 °F/60 °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 H_2S release rate is greater than:

— 0.01 cubic meters per second (m^3/s) or greater and less than 0.1 m^3/s and which is located within 500 meters (m) of the boundaries of an urban center;

— 0.1 m^3/s or greater and less than 0.3 m^3/s and which is located within 1.5 km of the boundaries of an urban center;

— 0.3 m^3/s or greater and less than 2.0 m^3/s and which is located within 5 km of the boundaries of an urban center; or

— 2.0 m^3/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 H_2S content of greater than 10 ppm; for purposes of equipment, refer to NACE MR 0175.

3.1.57
sour
An H_2S concentration equal to or greater than 10 ppm, and is consistent with 8-hour occupational exposure limit (OEL) for workers exposed to H_2S.

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.

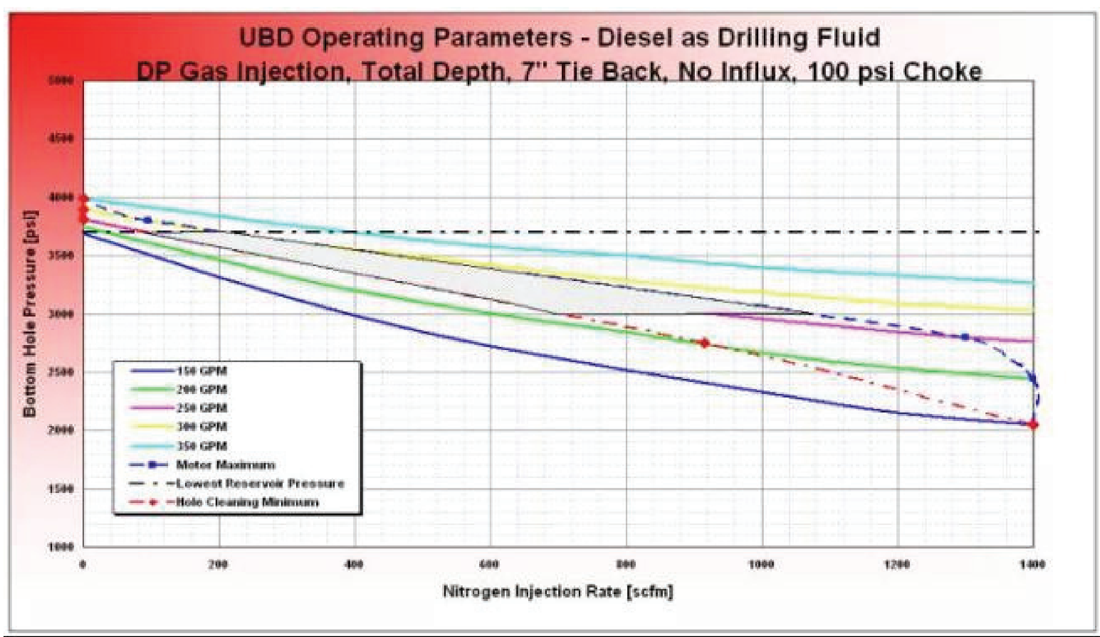

Figure 1—Example of a Steady State Subsurface Operating Envelope

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 it's 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.

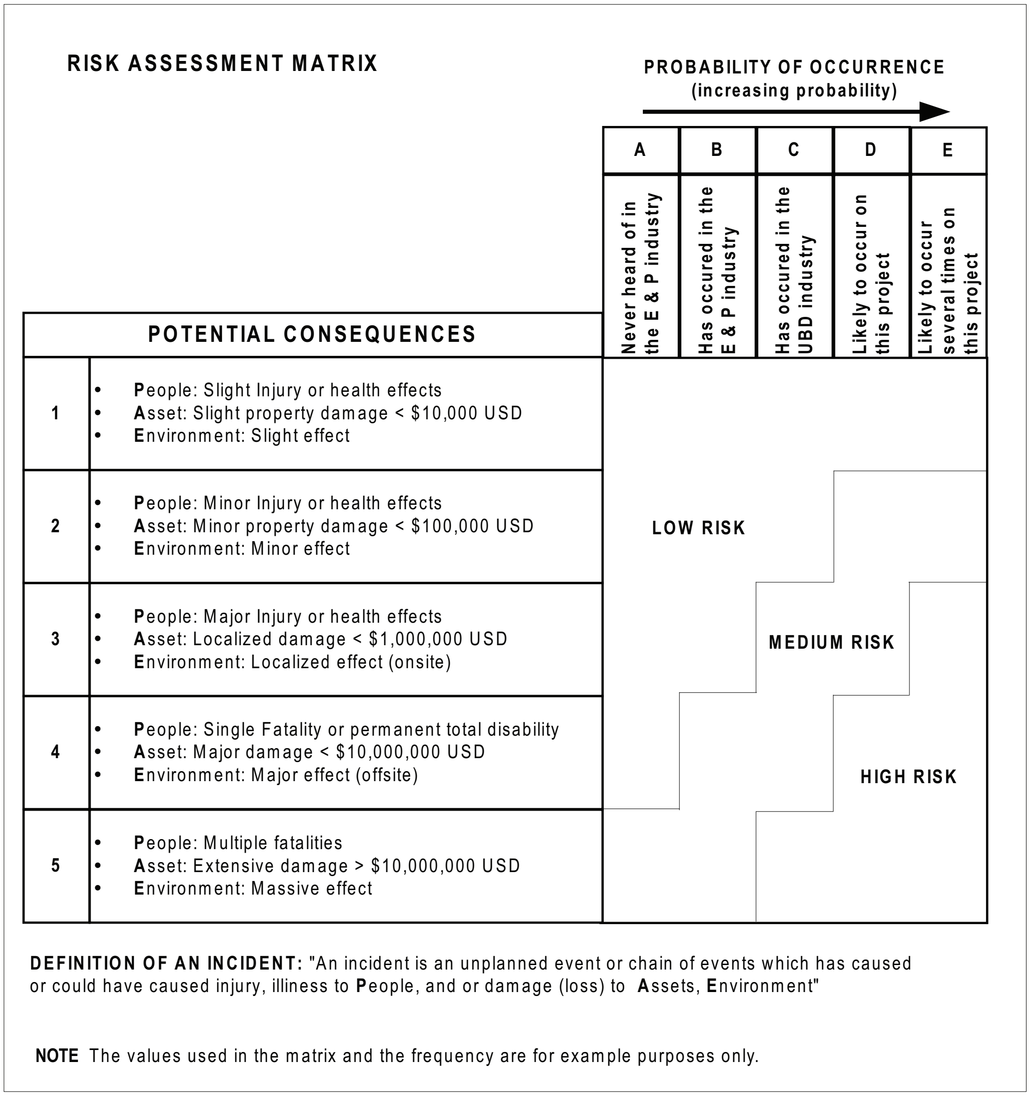

Figure 2—Hazard Matrix Chart

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.

a) They provide at least the same level of safety and public protection as those they are replacing.

b) The appropriate technical experts have reviewed the design and that this review is included in the project documentation.

c) 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.

d) 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).

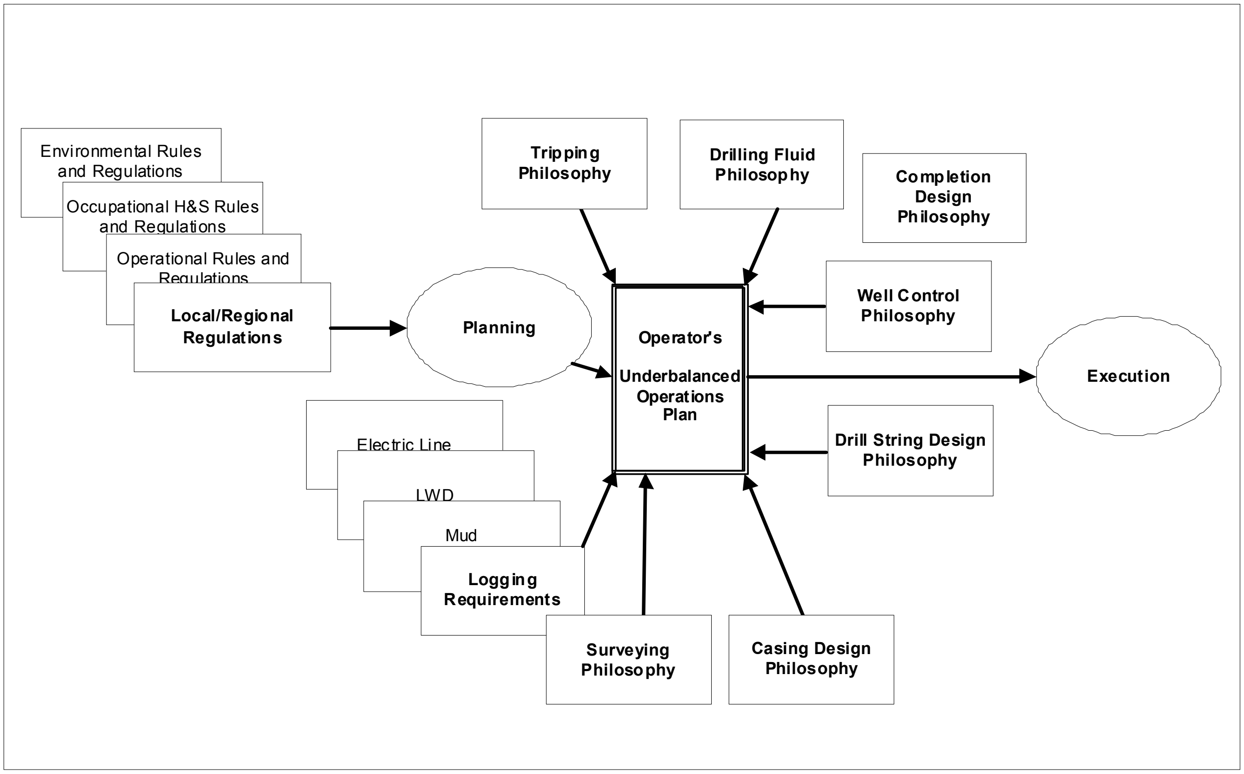

Figure 3—Planning Chart

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 ">Max_3" (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:

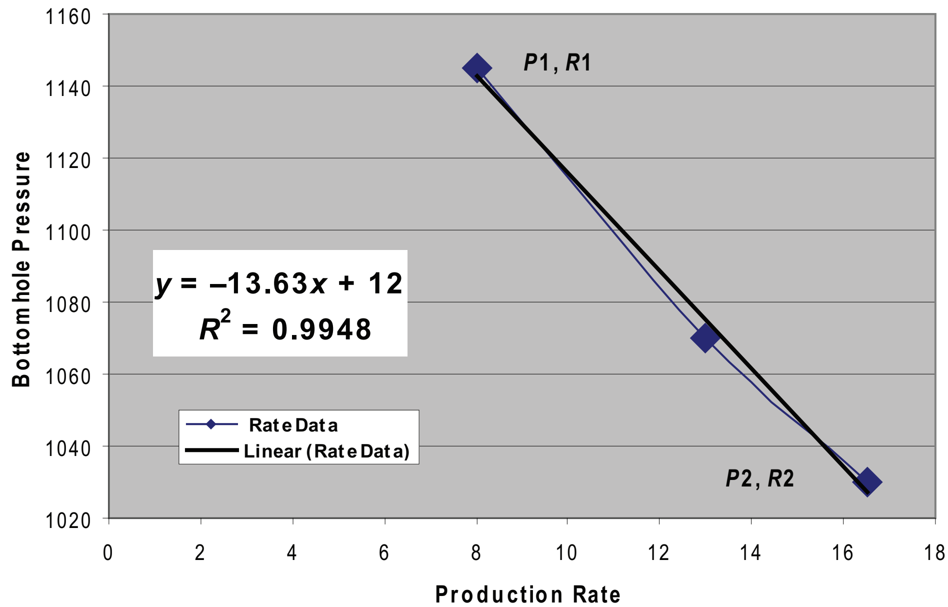

Figure 4—Bottomhole Pressure (BHP) Estimate Chart

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

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 $(MASP > MAWP_{RCD})$, *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 recertification procedure, or two years, whichever is less) of thickness inspection and hydrostatic pressure test.

6.2.11.7.2 Testing certificates and piping material properties certificates shall be available on request.

6.2.11.8 Wellsite Testing and Certification

6.2.11.8.1 Where erosion calculations indicate there may be an erosion concern during the UBD operations, piping should be thickness tested (i.e. ultrasonically) at predetermined erosion spots to determine loss of piping thickness, 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, H_2S 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.

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.

Exceptions. Flare lines, flowlines downstream of the choke manifold, standpipe manifold and the kelly hose (see 4.3.3).

National pipe thread (NPT) is acceptable to a maximum pipe OD of 25.4 mm (1 in.) in accordance with API 6A (see Section 3, Part B1B).

6.3.3 Wireline Equipment

In the absence of API or other standards, wireline pressure deployment systems used in a UBD operation should conform to the following guidelines:

— IRP 2, Section 7.5.1, Equipment Specifications;

— IRP 2, Section 7.5.2, Equipment Configuration;

— IRP 2, Section 7.5.4, Bolting, (Except Cold Service);

— IRP 2, Section 7.5.5, Certification.

6.3.4 Metallic Materials—Sour UBD Operation Materials

In the absence of applicable regulatory requirements, all metallic materials utilized in the pressure containing system used in a sour UBD operation, including BOPs, equalizing lines and bleed-lines, shall conform to the following:

— IRP 1, Section 5.5.1, BOP Metallic Materials for Sour Service;

— IRP 1, Section 5.5.2, Bolting Requirements;

— IRP 1, Section 5.7, BOP Transportation, Rigging Up and Maintenance;

— IRP 1, Section 9, Welding.

6.3.5 BOP Control System

6.3.5.1 Installation, maintenance, function testing and pressure testing of all BOP control systems used in a UBD operation should be in accordance with API 53.

6.3.5.2 Where applicable all BOP control systems shall conform to applicable regulatory requirements for the type of rig being used, e.g.:

— drilling rig;

— service rig or workover hoist;

— CT rig;

— snubbing units.

6.3.5.3 Auxiliary BOP equipment shall be installed to operate independently of the primary BOP control system and to the manufacturer's specifications.

6.3.6 Lift Gas Injection System (if Required)

Lift gas injection equipment should have a working pressure equal to or greater than the MASP.

6.4 Elastomers

6.4.1 This section applies to all elastomers in the pressure containing system, as well as any elastomers in pressure control devices which are run as part of the drill string.

6.4.2 Manufacturer-supplied performance specifications and recommendations shall be used for seal design, packaging, storage and shelf life.

6.4.3 If manufacturer-supplied performance specifications and recommendations for elastomers are not available for anticipated UBD conditions, specific testing of elastomers should be performed based on the UBD conditions.

6.4.4 This is especially critical when selecting materials and equipment for the UBD of a sour well.

Refer to:

— IRP 2, Section 11, Guidelines for Selecting Elastomeric Seals;

— IRP 2, 11.2, Service Conditions;

— IRP 2, 11.3, Seal Design.

6.4.5 Testing and Evaluation

6.4.5.1 Compatibility of any elastomeric seal with the intended service should be determined when selecting materials and equipment for a UBD project. This includes consideration of the effect of any fluid or substance that elastomer seals may be exposed to, as well as ambient temperatures at which seals are required to perform.

6.4.5.2 To evaluate the suitability of elastomers for a particular well, the well operator should first refer to the equipment manufacturer's recommendations. These recommendations should be based on materials testing and experience.

6.4.5.3 The operator should ensure that the information or data on seal materials meets the intended service requirements. If no data is available, a project-specific testing program should be performed to determine an elastomer's suitability.

6.4.5.4 Testing Methodology

No industry standards exist for the project-specific testing of elastomers for oilfield equipment. An example of available project-specific testing methodology for elastomers could include, but not be limited to, the following:

EXAMPLE

Place elastomer samples in an autoclave and introduce the samples to a representative UBD environment taking into consideration the pressure, temperature, reservoir fluid composition, drilling fluid composition and exposure times. The elastomer samples could then be evaluated to determine their suitability for the project-specific application by utilizing some or all of the test methods listed below:

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

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

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

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

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

6.4.5.5 Since most BOP manufacturers utilize proprietary formulas for their elastomers it is recommended that any testing be performed in conjunction with the BOP manufacturer and a qualified elastomer expert (see IRP 2, Section 11.3, Testing and Evaluation).

6.4.5.6 Records

The well operator shall ensure that records identifying the elastomer materials in use for all pressure control seals are available and, during UBD operations, this information should be available at the wellsite (see IRP 2, Section 11.4, Quality Control).

6.5 Inspection and Testing—Critical Sour Wells

6.5.1 Certification

6.5.1.1 All pressure control equipment shall be inspected, certified and pressure tested to the manufacturer's standards immediately prior to its use on the well where critical sour UBD operations will be conducted.

6.5.1.2 Documentation of the inspection, certification and testing shall be kept on the wellsite during the critical sour drilling operation.

6.5.1.3 In the absence of applicable regulatory requirements, procedures for inspection, pressure testing and certification are outlined in the following documents:

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

— IRP 2, Section 10, Quality Programs for Well Pressure Containing Equipment.

7 Drill String

7.1 Scope

7.1.1 This section addresses drill string components exposed to well effluent during UBD operations. As used in this section, the terms "drill pipe" and "drill string" are consistent with definitions in 3.1.17 and 3.1.18.

7.1.2 Integrity of the drill string means that there is pressure isolation between circulated fluids inside the drill string and wellbore fluids or the atmosphere outside the drill string, except where otherwise designed. This 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. Rotary hose discussions in this section relates to the subject of component pressure integrity.

7.1.3 Unless otherwise stated, drill string design should be carried out in accordance with API 7G.

7.2 Gaseous Fluid Injection via Drill Pipe

7.2.1 Many operating companies, service companies and rig contractors have implemented policies that prohibit the pumping of energized (gasified) fluids through rubber hoses. The rotary (kelly) hose is made of rubber and in most cases is subject to such a policy. There is sound reasoning and an HSE case for concern about pumping a high pressure gasified fluid through a kelly hose and UBD project teams should comply with these policies. However, many UBD operations, both onshore and offshore, have been conducted where gas (air, nitrogen or natural gas) was a component of the fluid injected down the drill pipe. Careful attention to the hazards associated with this type of operation, proper planning and application of sound risk management techniques have allowed safe conduct of these operations without incident.

7.2.2 The project team needs to understand the hazards. These will usually be identified during HAZID/HAZOP studies. Specific to injecting an energized fluid via the kelly hose, the hazard is the unplanned release of the energized fluid either due to a leak or a catastrophic failure of the hose and will generally be covered by the following threats:

— chemical incompatibility of the pumped fluid and the rubber compound in the hose material;

— grade and/or temperature rating of the hose make it unsuitable for the service;

— age or lifecycle implications of the hose material;

— previous service, damage and/or misuse of the hose.

The project team should determine if the equipment to be used is fit for purpose, whether or not injection of multiphase fluid down drill pipe is anticipated.

7.2.3 Pre-project inspection of the kelly hose should be conducted. To accomplish this, the project team should be familiar with API 7 for rotary drill stem elements and the associated recommended practices; specifically for rotary (kelly) hoses and the implications of using them under certain conditions. See the following examples.

— Rotary hoses manufactured in compliance with API 7K are suitable for use with oil-based mud, water based mud and crude oil with no gas (i.e. “stock tank crude”). Hoses manufactured to this specification are NOT suitable for continuous gas injection and also NOT suitable for H_2S service.

— The project team should be familiar with the conditions that can lead to explosive decompression of the rotary hose and the critical factors that affect this.

— If continuous gas injection via the standpipe is required, a rotary hose manufactured in accordance with API 17B should be used. These hoses will be made with a Therban® [11] or similar liner (that allows the gas to pass through easier than through an ordinary liner) and a stainless steel inner strip-wound tube, which supports the hose liner to prevent its collapse when the conditions for explosive decompression are present.

7.2.4 Prior to commencement of gaseous fluid injection operations, the project team should confirm that the properly inspected hose is installed on the rig. Visual inspection should be conducted to confirm there is no change in the condition of the kelly hose, which would make it unfit for the job.

7.3 General Requirements—Drill Pipe

In a jointed pipe UBD project, the drill pipe is a critical component of the flow control system. The quality and condition of the pipe (internal and external as well as the tool joints) is key to not only achieving the underbalanced well objectives but it can negatively impact the primary well control equipment, principally the RCD and the NRV.

7.3.1 The transition from the drill pipe OD to tool joint upset OD should be gradual with a minimum taper length in the range of 88.9 mm (3.5 in.) to 114.3 mm (4.5 in.) for external upset drill pipe. This should also be taken into consideration if heavyweight drill pipe with a mid-joint upset will be used as part of the UBD string.

7.3.2 The need for gas-tight connections should be considered on gas wells classified as IADC Level 4 or 5. However, it is acknowledge that standard connections (IF, FH, etc.) are routinely used without incident in UBD applications.

[11] This term is used as an example only, and does not constitute an endorsement of this product by API.

If a gas-tight connection is deemed necessary, the drill pipe manufacturer should be capable of demonstrating and confirming that the connection type is gas tight for drilling conditions (both for conventional and UBO).

7.3.3 Drill pipe grades SU-75 or SU-95 and tubing grade SU-80 should be used for wells classified as critical sour. Drill strings not originally manufactured to meet SU-75, SU-80 or SU-95 material and performance specifications should meet all of the requirements stipulated for the appropriate SU grade to qualify for use in critical sour UBD.

7.3.4 Hard banding, API identification grooves and internal plastic coating are normally accepted modifications to the drill pipe used in conventional drilling operations. Although not directly related to the integrity of the drill string, these can have an impact on the integrity of critical components of the pressure containment system.

7.3.4.1 *Hard banding*. Wear-resistant alloy overlay should be smooth. Application of raised face tungsten carbide hard banding is not recommended because of potential damage to the casing and to the RCD's sealing element.

7.3.4.2 *API identification grooves*. API identification grooves should be filled in. Drill pipe with identification grooves is not recommended because of the damage it causes to the RCD's sealing element, especially in high-pressure applications. However, it is recognized that tool joints with grooves have been successfully used under low-pressure UBD conditions.

7.3.4.3 On wells classified as IADC Level 4 or Level 5, wear-resistant alloy overlay shall be smooth and the API identification grooves shall be filled in.

7.3.4.4 *Internal plastic coating*. Drill pipe that is internally plastic coated for corrosion protection can become problematic during UBD operations. The coating can fail when exposed to gaseous multiphase fluid injection down the drill string, resulting in unplanned trips due to plugged NRVs and MWD equipment. The problem is related to the type of coating used and quality assurance/quality control (QA/QC) procedures used during application of the coating and repairs to the tool joints. The following recommendations should be considered in the planning phase of the UBD project and become especially critical in applications where gaseous multiphase fluids will be injected down the drill pipe.

a) Obtain from the pipe owner, the details of the drill pipe and the type of internal coating.

b) Discuss with corrosion specialists and plastic coating suppliers the specifics of the application:

   1) that it is a UBD application;

   2) the stresses the pipe will be exposed to, e.g. bending, torsional, tensile, compressive, etc.;

   3) the conditions such as fluid types, temperature, internal drill pipe pressure; and

   4) that internal pressure will be bled to zero very quickly during connections.

c) Determine the recommended coating type for the application and an opinion on the suitability of the coating on the drill pipe to be supplied by the pipe owner if it is different from the recommendation.

d) If the type of coating or the quality of the coating and pipe to be supplied by the pipe owner is questionable—do not use; the risk and consequence of failure can be very high.

e) If cryogenic nitrogen will be used as the gaseous phase to the pumped down the drill pipe, consider using uncoated pipe. There is also the option to remove the old coating and use the pipe uncoated.

f) If membrane generated nitrogen will be used as the gaseous phase to be pumped down the drill pipe, and depending on the fluids and conditions specific to the project, corrosion may be a problem and the project team should ensure that either the pipe is coated with the recommended coating and/or a corrosion inhibition program will be in place.

7.4 General Recommendations for the Bottomhole Assembly (BHA)

7.4.1 To facilitate installation of NRVs in the drill string, a special NRV sub should be installed in the BHA. Depending on the BHA design, the NRV subs should be installed directly above the bit or as close to the motor as possible.

7.4.1.1 Two NRVs should be installed or assembled in tandem in the NRV sub.

7.4.1.2 After installation into the special NRV sub, each NRV insert shall be tested to 200 psi to 300 psi (1380 kPa to 2068 kPa) and then to the maximum working pressure, each for 10 minutes (two tests for each valve).

7.4.1.3 To prevent the NRV inserts from being expelled due to trapped pressure, the inserts should be retained in place by a locking mechanism.

7.4.2 The use of drill string jars should be carefully considered. This is especially critical if snubbing operations may be required.

8 Circulating Media

8.1 Scope

Circulating media system design forms an integral part of the planning and programming for UBD projects. This section provides guidelines for media properties, kill fluids, corrosion/erosion monitoring, scavengers/inhibitors, fluids handling, storage, trucking, and waste treatment/disposal.

The circulating media for purposes of this RP includes both injected and produced fluids as well as their mixtures.

8.2 Media Properties

8.2.1 Flammability and Explosive Limits

Hydrocarbons, when mixed with oxygen, may result in an explosive condition. In a closed circulation system where no oxygen is contained in the circulating stream, explosive conditions are usually not a concern. However, oxygen may be introduced into the circulating stream at various points such as at the gas injection equipment. As the percentage of oxygen within the circulating stream increases, the susceptibility of the mixture to ignition increases. The presence of H_2S may reduce the oxygen levels required to create a potentially explosive condition.

8.2.1.1 Explosive limits shall be established for all circulating media systems, which have the potential to introduce oxygen into the circulating stream. If explosive limits are not clearly defined, systems, which have the potential to introduce oxygen to the circulating stream shall not be used.

8.2.1.2 Explosive limits shall be documented and posted next to the oxygen monitoring system for all circulating streams, which contain oxygen. Procedures shall be put in place to ensure that these limits are never exceeded while conducting UBD operations.

8.2.2 Gas Hydrates

Hydrate plugs have an ice-like crystalline structure made up of water and hydrocarbon gases. Due to the chemical composition of this material, its freezing point is above the normal freezing point of fresh water. Plugs can form when a gas/water mixture experiences a pressure drop, which causes a localized cooling effect. A solid structure may start building up and, if not controlled, can completely block the flow path. Pressure drops may occur at various locations within a circulating system, such as inside tubulars, across choke manifolds, across flow path diameter changes, etc. When exposed to the appropriate pressure and temperature conditions, hydrates can form in a gas well, or a high gas content oil well, as it is being drilled underbalanced. Hydrates limit the ability to produce fluids, inject fluids and ultimately control the well safely.

8.2.2.1 A hydrate curve for the anticipated range of operating pressures and temperatures shall be generated for UBO involving aqueous fluid injection and/or methane injection/production.

8.2.2.2 If hydrate-forming conditions are possible and unless it can be proven that hydrates cannot be formed in the gas stream expected to flow from the well while drilling underbalanced, the drilling fluid should be changed or measures shall be taken to prevent hydrate formation. These measures should include, but are not limited to, the use of surface line heaters and the injection of fluids to appropriately control the freezing point of the circulated/produced fluid stream.

8.2.2.3 If methanol is introduced into the system, consideration shall be given to resultant changes in flammability limits.

8.2.3 Carrying Capacity

The flow properties and characteristics of multiphase circulating streams are typically more complex than for single-phase circulating streams. To ensure adequate hole cleaning while drilling with a multiphase system, a thorough understanding of cuttings transport under these conditions is necessary. Inadequate hole cleaning could result in the circulation returns path becoming packed-off, limiting the ability to circulate and thereby resulting in a potential loss of well control. The inability to circulate due to cuttings pack-off can result in a “stuck” drill string.

A multiphase flow simulation of the returning flow stream should be performed to ensure adequate hole cleaning through proper design and implementation of the underbalanced circulation system (see 4.2.1).

8.2.4 Separation Qualities

Surface separation of oil, water, gases, and solids contained in the circulating media is necessary during a UBD operation. Inadequate separation may result in a variety of problems including variability in circulating fluid properties which may result in flow modeling inaccuracies, loss of accurate injection/production volume measurements, and fluid carryover to the flare stack.

8.2.4.1 Calculations should be performed and procedures put in place to ensure that surface separation of solids, gases and liquids is sufficient to ensure that the ability to effectively circulate liquids downhole is not compromised.

8.2.4.2 Formation of emulsions may be a concern with specific circulating media/produced fluid combinations. This may result in pumping difficulties, which in extreme cases could result in plugged suction lines. Fluid density control may also be compromised when emulsions form. Operational practices such as the use of demulsifiers, line heaters, constant removal of emulsified fluids, etc., should be considered where emulsion formation is anticipated. If demulsifiers or other chemicals are introduced into the system, consideration shall be given to changes in fluid properties and flammability limits.

In applications where there is a significant risk of developing emulsion problems, lab testing should be conducted to determine the best combination of chemicals and heat required to break the emulsion.

8.2.4.3 The use of viscosified water-based, and or hydrocarbon-based fluids (emulsified or mixed with brine) in UBD operations may result in gas entrainment. Gas entrainment may result in vapor locking of fluid pumps and lack of fluid density control, as well as re-circulation of produced gases. Where the circulating system is open to the atmosphere (e.g. open storage tanks, drill pipe on connections), entrained gas may break out causing hazards to workers. These areas should be monitored and have controlled access and ventilation systems. Operations should be stopped and the area ventilated if worker exposure limits are exceeded.

8.2.5 Compatibility with Other Systems

The compatibility of the circulating media, both injected and produced, with other components of the circulating system, should be reviewed to address the potential for formation damage, corrosion and degradation of the circulating system components, both at surface and downhole. The presence of acidic gases (H_2S, CO_2), acidic fluids, oxygen and electrolytes in the circulating system can result in corrosive conditions and incompatibility with reservoir fluids. Corrosion of metals or degradation of rubber and elastomer components and seals can lead to failure of equipment, which could result in safety and/or environmental concerns.

8.2.5.1 The chemical composition of any additives to be used in the circulating media should be examined to ensure they do not contain constituents which could result in premature failure of elastomers, seals, etc., either alone or in combination with produced fluids (see 6.4 for detailed requirements).

8.2.5.2 If circulation of H_2S-contaminated drilling fluid is anticipated, operational concerns regarding H_2S compatibility with metallic components, elastomers and fluids handling/storage equipment shall be addressed.

Sour fluids may be stripped of H_2S by employing a properly designed scrubber system. Consideration should be given to deploy such a system if drilling fluid containing H_2S is to be re-injected into the wellbore.

8.3 Kill Fluids

8.3.1 Operational and/or safety considerations may require the killing of a well that is being drilled underbalanced. A minimum quantity of 1.5 hole volumes of kill fluid should be available at all times for immediate circulation into the wellbore. The kill fluid should provide for a minimum 220-psi (1517-kPa) overbalance when fully circulated.

8.3.2 Degradation of the kill fluid (e.g. gel strength if weighting material is required), lost circulation properties and the effects of winter operations should be taken into account when managing the kill fluid system.

8.3.3 Two pump units should be installed on site to ensure continuous deliverability of the kill fluid if required. Pump units should be sized assuming worst-case conditions for the zone(s) to be drilled through so that required rates and pressures can be provided to kill the well.

8.3.4 If weighting or lost circulation material (LCM) material is required to kill the well, consideration should be given to the ability to successfully circulate these materials through the BHA. Circulating subs above flow restrictions may be necessary.

8.4 Corrosion and Erosion Monitoring and Mitigation

Corrosion is the destruction of metal by chemical or electrochemical means. Potential agents for initiating corrosion include carbon dioxide, hydrogen sulfide, chlorides, and oxygen. All of the above can be introduced into the circulating system during wellbore or surface circulation of the circulating media. Corrosion results in pitting, embrittlement, stress cracking, and black sulfide coating. Factors that affect corrosion rates include pressure, temperature, and pH.

8.4.1 Steps should be taken to minimize the corrosive potential of the circulating media and produced fluids when corrosive conditions exist. These can include minimizing/eliminating oxygen, carbon dioxide, hydrogen sulfide, and chlorides in the injection stream; adding scavengers and/or inhibitors into the injection stream; or the use of corrosive resistant materials. A monitoring program should establish the effectiveness of corrosion control steps during UBD operations.

8.4.2 A corrosion-monitoring program should be designed and in place for the corrosion risks of the fluid being used.

— When drilling under corrosive conditions, the circulating media should be monitored to provide for an indication of corrosion and to determine the effectiveness of corrosion control measures being utilized.

— Corrosion indicators (rings, coupons, or suitable alternatives) should be installed at appropriate/practical circulating stream locations (surface piping, drill pipe, BHA, etc.) to measure corrosion rates if operating under potentially corrosive conditions. Corrosion indicators should be regularly inspected to establish corrosion rates.

— Consideration should be given to taking precautionary steps such as regularly tripping to inspect the drill string / BHA to establish the severity of downhole corrosive conditions when drilling in an area where the corrosive environment is not thoroughly understood.

8.4.3 Recommendations for H_2S monitoring are discussed in IRP 1, Section 12, and IRP 2, Section 12. These references deal with general requirements, equipment, communications etc. In the absence of applicable regulations and or operating company policy, on wells classified as sour and/or critical sour, consideration should be given to these references.

8.4.4 Nitrogen supplied from membrane generation units may introduce oxygen contamination into the wellbore, which can cause general corrosion problems.

8.4.4.1 The oxygen content of any injection stream shall be monitored to mitigate the risk of corrosion to downhole equipment and to ensure that explosive limits are never reached during UBD operations. Continuous readout monitors are required and their calibration reports should be available on site.

8.4.4.2 The use of an appropriate inhibitor for the casing and drilling components is recommended.

Erosion is the removal of material by mechanical means. Solids contained in the returning fluids stream typically result in erosion of surface UBD flow control equipment. Factors that affect erosion rates include concentration, type and size of solids, and transport velocity.

8.4.5 Surface equipment exposed to high pressures and/or high flow velocities shall be inspected on a regular basis using industry-accepted practices to monitor for materials erosion.

8.4.6 Circulation parameters should be monitored to ensure that the system capabilities (including erosional velocities) are not exceeded. Parameters that require monitoring include, but are not limited to, gas and liquid production rates, injection pressures, wellhead annular pressure, bottomhole annular pressure, and surface volumes.

8.5 Fluids Handling, Storage and Trucking

Operators shall have site-specific plans in place for collection, transportation and disposal of hazardous fluids and/or gases.

8.5.1 Equipment Spacing

In the absence of applicable regulations, consideration should be given to API 500.

8.5.2 Fluids Handling System

8.5.2.1 In a UBD operation utilizing crude oil as the drilling fluid, circulated liquids should be contained in a closed circulation system.

8.5.2.2 In a sour UBD operation, all circulated liquids shall be contained in a closed circulation system unless H_2S levels can be reduced to meet occupational exposure limits (OELs), which would then allow the use of open tanks.

8.5.3 Onsite Storage Capacity

8.5.3.1 Sufficient storage capacity should be available to temporarily store produced fluids during drilling operations. “Flush” production is to be considered in determining storage requirements. Alternatively, provisions for fluid injection or offsite fluids transport should be in place if onsite facilities do not have the capacity to handle the necessary volumes.

8.5.3.2 Consideration should be given to providing additional storage capacity in the event of unforeseen circumstances, such as inclement weather conditions, which may compromise proper fluid handling abilities.

8.5.3.3 In a sour UBD operation, sour fluid volumes stored on the wellsite should be minimized for added safety of onsite personnel.

8.5.4 Fluids Transport

8.5.4.1 Spill contingency plans for storage, loading, unloading and transporting fluids shall be included in the operators site specific ERP.

8.5.4.2 Refer to existing industry documents and regulatory requirements regarding the transportation of hazardous fluids.

8.6 Waste Treatment/Disposal

8.6.1 Waste management plans for discarded liquids and drilled solids should be developed prior to commencement of UBD operations. This plan should consider the volume of solids that will be generated and their residual oil, chloride and H_2S content (if applicable).

8.6.2 In a sour UBD operation, the waste handler used for disposal should be contacted in advance to determine their sour fluids and sour solids handling capabilities.

9 Well Integrity

9.1 Purpose

9.1.1 This section highlights the concerns and implications regarding wellbore integrity when exposed to effluent flow from a well during UBD operations.

9.1.2 The recommendations include design and verification requirements to be considered when assessing the condition of the casing, the wellhead, and the cement in an existing or new wellbore before undertaking a UBD operation.

9.2 General

9.2.1 Casing, cement and the wellhead are considered both primary and secondary well control barrier elements during drilling operations. Therefore, wellbore integrity refers to both the ability and the reliability of the open-hole, casing, cement, and the wellhead to contain the wellbore fluids. Loss of containment during UBD can be caused by a failure of the casing, the cement or the wellhead (includes the BOP and RCD). The integrity of the exposed formations in the open hole reservoir section relates more to wellbore stability issues rather than a loss of containment.

9.2.2 The possible ways the wellbore could lose integrity and containment should be identified in the HAZOP. The risks of failure once the causes are identified can be mitigated by appropriate wellbore design and adequate assessment of current integrity of the candidate wellbore.

9.2.3 For offshore purposes, the splash zone of the conductor (if an existing well is used) should be checked for wall thickness, etc., to ensure that the load of the stack (including snubbing stack) can be supported.

9.2.4 Typical UBD conditions that are not seen during overbalanced drilling operations are:

— exposure of the wellbore to reservoir fluids;

— reduced BHP and temperature;

— high surface pressures;

— high flow rates;

— reservoir pressure to surface if the well is shut in.

9.2.5 Figure A.1 is an example of a systematic approach to evaluate current casing integrity. In addition, specific consideration should be given to the following:

— casing (include conductor and riser analysis for offshore applications);

— casing metallurgy—for critical sour wells;

— sulfide stress cracking (SCC);

— casing wear;

— casing wear assessment.

10 UBD Operations

10.1 Sour Underbalanced Drilling Operations

During UBD operations, equipment components normally exposed to drilling fluids will be exposed to formation fluids. If these formation fluids are likely to contain hydrogen sulfide gas, all UBD flow control equipment (with the exception of storage tanks) shall conform to NACE MR 0175 (SCEPCO1) specifications. Material selection and quality control are required to ensure satisfactory performance in the service to which the material is exposed. As a minimum, the original manufacturer of the components shall provide quality assurances with test certification, that the equipment supplied meets the requirements of NACE MR 0175. The scope of the NACE MR 0175 standards is limited to acceptable metallurgy for sour service. The suitability of a number of sub-components constructed of non-metallic material such as elastomers, shall also be considered.

NACE MR 0175 specifications do not apply to storage tanks since fluids are stored below 50.8 psi (350 kPa).

10.2 Well Control Equipment

10.2.1 Due to the critical nature of UBD operations, expendable BOP and RCD parts such as packers, seals, gaskets, etc. shall be original equipment manufacturer supplied parts.

10.2.2 Original equipment manufacturer supplied elastomeric seals shall be certified as meeting the intent of 6.4 of this document.

10.2.3 Secondary well control equipment shall not be used to enable drilling ahead, tripping, stripping (other than a planned RCD element change).

10.2.4 The original BOP control system manufacturer shall be consulted in the event that the field calculations or field testing indicate insufficient capacity or in the event that the volumetric requirements of equipment being controlled are changed, such as by the modification or replacement of the BOP stack.

10.3 Minimum Equipment

10.3.1 Well Classified as IADC Level 0

IADC Level 0 wells are defined as drilling performance enhancement only; no hydrocarbon containing zones in the section to be drilled underbalanced. The minimum recommended equipment required is illustrated in Table 8. UBD wells classified as IADC Level 0 are generally wells being drilled with dry air/N2, mist or foam. See 10.8.1 for operational guidelines specific to these operations.

Table 8—IADC Level 0 Minimum Equipment

Drilling Fluid:	**Air/Mist/Foam**			
Formation Fluid:	* Reference Comments			**Y**=yes, **O**=Optional, **NA**=Not Applicable
	Sweet			**Comments**
Level 0				
BOP (preventers & annulars)	O			May require BOPs per local regulations
				* May encounter minor gas shows and minor waterflows in the section.
Rotating Control Device	Y			In specific cases, an RCD can be considered optional. For example drilling a non-hydrocarbon section with a known water flow potential. Flow can either be accepted or conrolled dynamically while drilling.
Blooey Line	Y			Dresser Sleeve **not** recommended
Venturi	O			
Auto Igniter	NA			
Feed Compressor	Y			
Booster Compressor	Y			
Mist Pump	O			Recommended
Pipework	Y			
Bleedoff Manifold	Y			Full-opening gate valve, **not** a ball type valve
Non-Return Valves (flapper type)	Y			NRVs in BHA and string floats (retrievable or non-retrievable) as required (max 500 ft apart)
Closed system	NA			
Flexible hose and swivel packing	Y			
LEL Monitor	O			
Gas Chromatagraph	O			

10.3.2 Well Classified as IADC Level 1

IADC Level 1 wells are defined as wells incapable of natural flow to surface. The well is "inherently stable" and is a low-level risk from a well control point of view. UBD wells classified as IADC Level 1 are generally sub-normally pressured oil wells requiring some type of lift mechanism to produce. The minimum recommended equipment required is illustrated in Table 9.

Table 9—IADC Level 1 Minimum Equipment

Drilling Fluid:	**Gas/Multiphase**			
Formation Fluid:	**Multiphase**			**Y**=yes, **O**=Optional, **NA**=Not Applicable
	Sweet			**Comments**
Level 1				Requires gas supply: Air, Cryogenic N2, Membrane N2, Natural gas or Waste gas
Flame arrestor	Y			
Separator	Y			Atmospheric (recommended)
Closed System	O			
Low Pressure Choke Manifold	O			Subject to HAZOP Review
BOP (preventers & annulars)	Y			2 Rams + Annular
Rotating Control Device	Y			
Blooey Line	NA			
Flare Stack or Pit	Y			
Auto Igniter	O			**NA** with Atmospheric Separator
Feed Compressor	Y			
Booster Compressor	Y			
Mist Pump	O			
Pipework	Y			
Non-Return Valves	Y			
Flexible hose and swivel packing	O			
Check valves	O			
Metering	O			
Relief valves	O			
Bleedoff Manifold	Y			Full-opening gate valve, **not** a ball type valve
LEL Monitor	O			Recommended if using air or Membrane N2 as lift gas
Gas Chromatagraph	O			Recommended if using air or Membrane N2 as lift gas

10.3.3 Well Classified as IADC Level 2

IADC Level 2 wells are defined as wells capable of natural flow to surface but can be controlled using conventional well kill methods. Catastrophic equipment failure may have limited consequences. UBD wells classified as IADC Level 2 are generally abnormally pressured water zones, low flow rate oil or gas wells or depleted gas wells. These wells generally require some type of lift mechanism to produce. The minimum recommended equipment required is illustrated in Table 10.

Table 10—IADC Level 2 Minimum Equipment

Drilling Fluid:	Gas/Multiphase		
Formation Fluid:	Gas	Multiphase	**Y**=yes, **O**=Optional, **NA**=Not Applicable
	Sweet	Sweet	Comments
Level 2			Requires gas supply: Air, Cryogenic N2, Membrane N2, Natural gas or Waste gas
Flame arrestor	Y	Y	
Separator	Y	Y	Atmospheric
Closed System	O	O	
Low Pressure Choke Manifold	O	O	Subject to HAZOP Review
BOP (preventers & annulars)	Y	Y	3 Rams + Annular
Rotating Control Device	Y	Y	
Blooey Line	O	NA	
Flare Stack or Pit	Y	Y	
Auto Igniter	O	O	**NA** with Atmospheric Separator
Feed Compressor	Y	Y	
Booster Compressor	Y	Y	
Mist Pump	O	O	
Pipework	Y	Y	
Non-Return Valves	Y	Y	
Flexible hose and swivel packing	O	O	
Check valves	O	O	
Metering	O	O	
Relief valves	Y	Y	
Bleedoff Manifold	Y	Y	Full-opening gate valve, **not** a ball type valve
LEL Monitor	O	NA	Recommended if using air or Membrane N2 as lift gas
Gas Chromatagraph	O	NA	Recommended if using air or Membrane N2 as lift gas

10.3.4 Well Classified as IADC Level 3

10.3.4.1 IADC Level 3 wells are defined as wells having geothermal and non-hydrocarbon production. Maximum shut-in pressures less than UBD equipment operating pressure rating. UBD wells classified as IADC Level 3 include normally pressured geothermal wells with H_2S present. The minimum recommended equipment required for this type of well is illustrated in Table 11.

Table 11—IADC Level 3 Minimum Equipment

Drilling Fluid:	Gas/Multiphase			
Formation Fluid:	Multiphase			**Y**=yes, **O**=Optional, **NA**=Not Applicable
	Sweet			Comments
Level 3				May or may not require lift gas supply
Separator	Y			
Closed System	O			Recommended for wells with H2S present
Emergency Shutdown Systems	O			
Pipework	Y			
Choke Manifold	Y			
BOP (preventers & annulars)	Y			3 Rams + Annular
Rotating Control Device	Y			
Flare Stack or Pit	Y			
Auto Igniter	O			
Feed Compressor	O			
Booster Compressor	O			
Non-Return Valves	Y			
Metering	O			
Relief valves	Y			
Bleedoff Manifold	Y			Full-opening gate valve, **not** a ball type valve

10.3.4.2 Casing point should be set deep enough to enable a shut-in in the event of a loss of primary well control.

10.3.5 Well Classified as IADC Level 4

10.3.5.1 IADC Level 4 wells are defined as having hydrocarbon production. Maximum shut-in pressures less than UBD equipment operating pressure rating. Catastrophic failure will likely have immediate serious consequences. UBD wells Classified as IADC Level 4 include high pressure and/or high flow potential reservoirs, sour oil and gas wells, offshore environments or simultaneous drilling and production operations The minimum recommended equipment required for this type of well is illustrated in Table 12.

Table 12—IADC Level 4 Minimum Equipment

Drilling Fluid:	**Gas/Multiphase**				
Formation Fluid:	**Gas**		**Multiphase**		**Y**=yes, **O**=Optional, **NA**=Not Applicable
	Sweet	**Sour**	**Sweet**	**Sour**	**Comments**
Level 4					May or may not require lift gas supply
Flame arrestor	Y	Y	Y	Y	
Multi-Phase Separator	Y	Y	Y	Y	
Closed System	O	Y	O	Y	
Emergency Shutdown Systems	O	Y	O	Y	
Choke Manifold with redundant flow paths	Y	Y	Y	Y	
BOP (preventers & annulars)	Y	Y	Y	Y	3 Rams + Annular
Rotating Control Device	Y	Y	Y	Y	
Flood pump (deluge) on Annulus	O	O	O	O	
Flare Stack or *Pit	Y	Y	Y	Y	* Flare pit is optional for sweet gas wells
Auto Igniter	Y	Y	Y	Y	
Feed Compressor	O	O	O	O	
Booster Compressor	O	O	O	O	
Mist Pump	O	O	O	O	
Pipework	Y	Y	Y	Y	
Non-Return Valves	Y	Y	Y	Y	
Flexible hose and swivel packing	O	O	O	O	
Check valves	Y	Y	Y	Y	
Metering	Y	Y	Y	Y	
Relief valves	Y	Y	Y	Y	
Bleedoff Manifold	Y	Y	Y	Y	Full-opening gate valve, **not** a ball type valve
Drilling String (Gas Tight Connections)	O	O	O	O	Recommended on HP high rate gas wells
Gas Tight Rotary Kelly Hose	O	O	O	O	Recommended if injecting multiphase fluids down DP
LEL Monitor	O	O	O	O	Recommended if using air or Membrane N2 as lift gas
Gas Chromatagraph	O	O	O	O	

10.3.5.2 Casing point should be set deep enough to enable a shut-in in the event of a loss of primary well control.

10.3.6 Well Classified as IADC Level 5

10.3.6.1 IADC Level 5 wells are defined as having MASPs that exceed UBO equipment operating pressure rating. Catastrophic failure has immediate serious consequences. IADC Level 5 wells Include any UBD well where the MASP is greater than UBO/MPD equipment pressure rating, thus requiring BOP equipment to be activated in the event the well must be shut-in. The minimum recommended equipment required for this well classification is illustrated in Table 13.

10.3.6.2 Casing point should be set deep enough to enable a shut-in in the event of a loss of primary well control.

10.3.7 Safety Critical Spares

For all IADC well classification levels, a list of "critical spares" equipment should be available from the contractors. As a minimum requirement, equipment deemed "safety critical" should have spares available on site to safeguard the operation at all times. Operations shall cease in the event of "safety critical" equipment failure.

10.4 UBD Flow Control Devices

10.4.1 Dedicated UBD-CD and UBD flow control system components shall be installed for UBD operations and shall not be considered as replacement for conventional well control equipment.

Table 13—IADC Level 5 Minimum Equipment

Drilling Fluid:	Gas/Multiphase				
Formation Fluid:	Gas		Multiphase		Y=yes, O=Optional, NA=Not Applicable
	Sweet	Sour	Sweet	Sour	Comments
Level 5					May or may not require lift gas supply
Flame arrestor	Y	Y	Y	Y	
Multi-Phase Separator	Y	Y	Y	Y	
Closed System	O	Y	O	Y	
Emergency Shutdown Systems	O	Y	O	Y	ESD System protocol includes activation of the BOPs in the event of a shut-in
Choke Manifold with redundant flow	Y	Y	Y	Y	
BOP (preventers & annulars)	Y	Y	Y	Y	4 Rams + Annular
Rotating Control Device	Y	Y	Y	Y	Usually rated for less than the maximum expected shut-in pressure at surface
Flood pump (deluge) on Annulus	Y	Y	Y	Y	
Flare Stack or *Pit	Y	Y	Y	Y	* Flare pit is optional for sweet gas wells
Auto Igniter	Y	Y	Y	Y	
Feed Compressor	O	O	O	O	
Booster Compressor	O	O	O	O	
Mist Pump	O	O	O	O	
Pipework	Y	Y	Y	Y	
Non-Return Valves	Y	Y	Y	Y	
Flexible hose and swivel packing	O	O	O	O	
Check valves	Y	Y	Y	Y	
Metering	Y	Y	Y	Y	
Relief valves	Y	Y	Y	Y	
Bleedoff Manifold	Y	Y	Y	Y	Full-opening gate valve, **not** a ball type valve
Drilling String (Gas Tight Connections)	O	O	O	O	Recommended on HP high rate gas wells
Gas Tight Rotary Kelly Hose	O	O	O	O	Recommended if injecting multiphase fluids down DP
LEL Monitor	O	O	O	O	Recommended if using air or Membrane N2 as lift gas
Gas Chromatagraph	O	O	O	O	

10.4.2 The accumulator and or power system used to operate UBD-CDs shall be independent of the rig's standard BOP accumulator system.

10.4.3 Drill string NRVs shall be incorporated into the drill string to prevent flow up the drill string.

A minimum of two NRVs should be placed in the BHA directly above the bit.

In a directional drilling assembly where a downhole motor is being used, the NRVs should be placed as close to the motor as possible.

10.4.4 Installation

10.4.4.1 UBD surface equipment shall be installed in accordance with the site-specific P&ID or PFD. The P&ID or PFD shall include the site-specific BOP stack arrangement.

10.4.4.2 The PFD diagram shall at a minimum include the valve numbering sequence of the BOP and RCD component valves, primary flowline valves, secondary flowline valves and the UBD choke manifold valves.

NOTE To facilitate valve and pressure management during underbalanced operations, the PFD and BOP stack arrangement diagrams should be posted in the rig floor doghouse.

10.4.4.3 To reduce wear of the RCD packer element and the requirement for a premature RCD packer element replacement, ensure alignment of the RCD, BOP stack, rotary table and derrick.

10.5 Pressure Testing—BOPs

10.5.1 A complete BOP function and pressure test shall be conducted just prior to the start of the UBD operation.

10.5.2 All blowout prevention components that may be exposed to solids contaminated effluent flow and erosional velocities during UBD operations shall be pressure tested using procedures in accordance to API 53, unless otherwise specified herein.

10.5.2.1 Test procedures should be project specific and should be based on analysis of surface pressure scenarios, which may vary depending on the formation being drilled.

10.5.2.2 Testing of blind and blind/shear rams is conducted when there is no pipe in the hole to avoid hanging off the drill pipe in a live well.

10.5.2.3 All other tests are performed with sufficient pipe in the hole to prevent a pipe-light condition.

10.5.3 During UBD operations, the rig BOP equipment should be pressure tested at a minimum of once every three weeks and function tested every two weeks. BOP tests for different components of the stack may be performed on different days.

10.5.3.1 While underbalanced drilling, it may not be practical to perform a BOP test in accordance with API 53 without severely impacting the underbalanced well objectives, therefore, testing is usually performed during tripping operations.

10.5.3.2 Test frequency should be in accordance with this RP, applicable regulatory and or company standards whichever is most stringent.

10.5.4 Tests should be conducted using water as the test medium. In a cold weather operation or on gas filled wells, glycol or methanol water mixture should be used to prevent freezing or the formation of hydrates.

10.5.4.1 The mixture used shall be compatible with the elastomeric seal components of the BOP equipment.

10.5.4.2 If the circulating medium is a gaseous fluid and/or the wellbore effluent is expected to contain free gas, the hydrostatic test of the BOP stack should be followed with a pressure test using an inert gas medium.

10.5.4.3 Duration of the tests shall be for a minimum of 10 minutes after pressure has stabilized.

10.6 Pressure Testing While Commissioning

A site-specific pressure test and commissioning procedure is considered critical. It shall reflect the system design to prevent damage to the system and shall be linked to specific equipment installed in accordance with the PFD.

Prior to pressure testing, the UBD equipment installation shall be inspected and checked against the P&ID or PFD to confirm that it is safe to test. This inspection should employ a standard pressure test checklist to verify that, e.g. valves are in the correct open or closed positions, air cannot be trapped in the system, an adequate relief system has been provided, and the piping tie-down arrangements have been installed as planned.

10.6.1 Pressure Test

10.6.1.1 The pressure containing system shall be pressure tested with water for a minimum of 10 minutes. Pressure testing conducted at the wellsite shall conform to any applicable regulatory requirements.

10.6.1.2 A low-pressure test of 200 psi to 300 psi (1379 kPa to 2068 kPa) shall be applied to the system. The low-pressure test often identifies damage to the ram body and piston area from scouring, which if left un-repaired can lead to leaking well control equipment during UBD or in well control event on a conventional drilling operation.

10.6.1.3 Upon completion of a successful low-pressure test, the pressure shall be safely released to zero and a pressure equal to the MASP or the pressure rating of the BOP, RCD or the choke manifold, which ever is lower, shall then be applied.

10.6.1.4 After successful completion of the high-pressure test, the pressure should be safely released to zero. If the circulating medium is a gaseous fluid and/or if the wellbore effluent is expected to contain free gas, the pressure containing system should then be pressure tested with an inert gas to a pressure equal to 100 % of the pressure applied in 10.6.1.3. The pressure should be increased in 1000-psi (6895-kPa) stages and, at each stage, be allowed to stabilize for 2 minutes before proceeding to the next stage. After successful high-pressure gas test the pressure should be safely released to zero.

10.6.1.5 Documentation of the hydrostatic and gas pressure tests shall be kept at the wellsite for the duration of the UBD operation.

10.6.2 Procedural Guidelines

10.6.2.1 Test plugs (packer or a plugged tubing hanger) should be utilized to isolate the production casing and prevent exposure of the surface well control equipment to high-pressure cycles during pressure testing.

10.6.2.2 Install a ram-blanking tool (RBT) with the proper size drill pipe across the BOP, through the RCD packers and back to surface. To prevent pipe movement during the test, the lower pipe ram should be partially closed and the RBT pulled snug against the pipe ram.

10.6.2.3 Ensure the pipe is installed such that there is no movement possible in either the pipe rams or the RCD during the test or that a tool joint is not across the pipe rams or the RCD element during pressure testing.

10.6.2.4 Pressure the system using water to the low pressure specified in the pressure test procedure. After applying pressure, all system valves including the pipe ram and the blind ram (if below the RBT) should be fully closed sequentially proceeding from the well-bore side back to the choke manifold (except the annular BOP). Each section is then bled off sequentially proceeding from the outer valves to the innermost isolation point.

10.6.2.5 It is important to monitor the pressure within each isolated section with a chart recorder.

10.6.2.6 Pressure the system using water, to the high pressure specified in the pressure test procedure. Note: the high-pressure test should be to the MASP or the appropriate rating of the BOP, RCD and the choke manifold, which ever is lower. As in the low-pressure test, all valves including the pipe rams and the blind rams are closed sequentially proceeding from the well-bore side back to the choke manifold (except the annular BOP, refer to the note below). Each section is then bled off sequentially proceeding from the outer valves to the innermost isolation point.

NOTE The annular BOP should not be tested during this sequence since closing the annular BOP with the system pressured up could result in the RCD being exposed to a pressure higher than the design pressure.

10.6.2.7 After successfully function testing and pressure testing the system and isolation valves with water, a final test of the system with an inert gas is required to ensure gas tightness. The individual component valves are not tested. This test shall be restricted to the high-pressure sections from below the BOP, the primary and secondary flowline up to and including the choke manifold.

10.6.2.8 The system should be pressure tested to 100 % of the pressure used in step 10.6.2.6 against the primary isolation valves on the choke manifold and against the isolation packer or tubing hanger in the well and the lower RCD element. This is mainly to test the external connections in the system and the bearing seals for gas tightness.

10.6.2.9 Since the RCD element is designed to wear out during use it should not be intentionally exposed to its static pressure rating during the project execution. It must be remembered that the RCD it is not designed to act as a BOP.

10.6.2.10 To reduce the risk of explosive decompression of the elastomeric elements in the system, the gas pressure should be bled off slowly in a controlled manner until the pressure is less than 1500 psi (10,342 kPa).

10.7 Pressure Testing During Operations

10.7.1 Blowout Preventers

10.7.1.1 If a BOP test is required during the underbalanced operation, the BOPs should be tested using available surface pressure provided a minimum of 50 % of maximum anticipated wellhead pressure (WHP) is available.

10.7.1.2 If a BOP test is required during the underbalanced operation and the available surface pressure is less than 50 % of maximum anticipated WHP, the BOPs should be tested using N_2 and a test plug.

10.7.2 Pressure Containing System

10.7.2.1 If any connections in the pressure containing system are disassembled during operations, those connections shall be pressure tested in accordance with 10.5.1 before operations are continued.

10.7.2.2 All tests conducted on the snubbing stack annular-type BOPs (if applicable) shall be conducted with pipe in the hole.

10.7.3 Jointed-pipe Drill String

10.7.3.1 Prior to tripping the drill string into the hole, the NRVs within the drill string shall be pressure tested sequentially proceeding from the bottom up to 200 psi to 300 psi (1379 kPa to 2068 kPa) for a minimum of 10 minutes and to its rated working pressure for a minimum of 10 minutes utilizing a low viscosity fluid.

10.7.3.2 Prior to tripping the drill string out of the well, the NRVs within the drill string shall be inflow tested sequentially proceeding from the bottom up utilizing the pressure in the well at the bottom of the drill string, and reducing the pressure at the top of the drill string to atmospheric pressure. The top of the drill string shall then be monitored by a flow-check for a minimum of 10 minutes to determine if any leaks exist in the drill string pressure control devices.

If the drill string does not pass this pressure test, at least one pressure control barrier shall be added to the drill string and the pressure test repeated.

10.7.3.3 After pulling the drill string out of the hole and prior to re-running the drill string back into the well, the drill string NRVs shall be inspected and repaired as required.

10.7.4 Coiled Tubing Drill String

10.7.4.1 Prior to tripping the CT drill string into the hole, the double check valve in the BHA shall be bench-tested immediately prior to being run in the hole to 200-psi (1379-kPa) for a minimum of 10 minutes and to 1.1 times the MASP for a minimum of 10 minutes, both with an inert gas.

10.7.4.2 The CT drill string between the double check valve and the rotating joint on the CT reel unit should be pressure tested to 200-psi (1379-kPa) for a minimum of 10 minutes and 1.1 times the MASP for a minimum of 10 minutes, both utilizing a low viscosity fluid.

10.7.4.3 The pressure control devices in the BHA during pressure deployment operations into the hole shall be pressure tested sequentially proceeding from the bottom up utilizing wellbore pressure at surface.

10.7.4.4 If the pressure control devices in the BHA do not hold pressure from below during pressure deployment operations into the hole, the CT is to be pulled from the hole and the existing barriers replaced and re-pressure tested before pressure deployment operations into the hole continue. If any connections in the CT drill string between the double check valve and the rotating joint on the CT reeled unit are disassembled during operations, those connections shall be retested as outlined in this section before the CT drill string can be run back into the well.

10.8 Operational Guidelines

10.8.1 Air/N_2, Mist and Foam Drilling Operations

Air drilling has proven successful at reducing the chip hold-down pressure, thereby enabling maximum rate of penetration (ROP). This technique has also been used to reduce formation damage in shallow, water sensitive reservoirs. Although the term "air drilling" encompasses a wide range of drilling fluid flow variations, it is most often used to describe dry air circulation while drilling. See 10.3.2 for equipment considerations.

10.8.1.1 To reduce the HSE impact of an air drilling operation, the following considerations should be addressed prior to the start of operations:

— containment of cuttings;

— suppression of dust;

— containment of water suppression mists;

— containment and flaring of wellbore fluids;

— disposal of wastes;

— installation of noise suppression equipment in populated areas.

10.8.1.2 To mitigate HSE risk during an air drilling operation, the following should be onsite requirements.

— Monitor for lower explosive limit of the return flow stream (see 8.2.1).

— Record all hydrocarbon shows. Use of a gas chromatograph is recommended.

— Check all gas shows for H_2S.

— Ensure that lower choke line has been opened and any pressure has been bled-off prior to opening the blind rams after use.

The well shall be circulated with a kill fluid in the event of an H_2S gas flow.

10.8.1.3 To mitigate damage to BOP equipment during an air drilling operation, the following should be an onsite requirement:

— BOPs should be cleaned at least once every 24 hours by blowing out dust from the cavities using a perforated sub;

— BOPs should be cleaned prior to function testing.

10.8.1.4 To mitigate the risk of a downhole explosion, fire and/or uncontrolled release of explosive mixtures during an air drilling operation, in the event of an unexpected hydrocarbon show onsite safety-critical supervisors shall consider discontinuing the use of air as the primary component of the drilling fluid. The operation is no longer classified as an IADC Level 0 well. Switching from air to N_2 or methane as the gas phase of the drilling fluid shall be a key consideration in the event of a liquid hydrocarbon show.

10.8.2 To reduce the risk of HSE and operational incidents due to incorrect valve position (open/close), whenever an operational change (planned or unplanned) occurs, a valve position table is recommended as an integral element of the procedure.

Snubbing, stripping and pressure deployment is allowed after dark provided the lighting at the wellsite meets the requirements of 11.5.

Table 14—Valve Position Table

Valve Position Table—Specific Operation (EXAMPLE)		
Valve Location	**Valve Numbers (Open)**	**Valve Numbers (Closed)**
Snubbing BOP Stack		
Well Control BOP Stack		
BOP Equalization Line		
Stand Pipe Manifold		
Rig Choke Manifold		
Primary Flowline		
Gas Injection Manifold		
Secondary Flowline		
UBD Choke Manifold		
Tank Farm		

10.8.3 Rig Alignment

Regardless of the drive system used, misalignment of the rig with the wellbore can have a negative impact on the operation. With this in mind, it is prudent to have a good inventory of RCD packer elements properly stored on the wellsite.

Misalignment can potentially lead to metal debris in the hole, which can increase wear and tear on equipment and lead to nonproductive time. Use of ditch magnets and string magnets should be considered. Rig misalignment can also cause failure of spools or casing near surface possibly resulting in loss of well control.

10.8.4 Use of Near-surface NRVs

To facilitate gas blow-down during connections, install near-surface NRVs in the drill string. The actual number of near-surface NRVs and the interval of placement within the upper portion of the drill string are determined by how much hole is to be drilled underbalanced.

10.8.4.1 In addition to the NRVs in the BHA, near-surface NRVs should be inserted into the drill string at the point where UBD is to commence, and approximately every 200 m after that point until the underbalanced portion of the well is completed. The 200-m spacing is considered optimum for minimizing the time and cost associated with bleeding off the gas pressure from the drill string every time a connection is made.

10.8.4.2 Near-surface NRVs are not recommended unless gasified fluids are being injected down the drill pipe.

10.8.4.3 Near-surface NRVs shall be installed in NRV subs equipped with a lock-down device to prevent the inserts from being expelled by pressure trapped below the valve.

10.8.4.4 See 10.8.6 for safe removal of NRV.

10.8.5 Sour Well Operations

10.8.5.1 Prior to drilling into any formation that may contain H_2S gas, safety supervisors (see 11.7.1) and safety equipment (see A.2) shall be on the wellsite. The equipment shall be installed and ready for service, and crew members shall be trained in the use of the equipment.

10.8.5.2 If the well is not expected to flow during tripping operations consideration should be given to bull-heading a nitrogen blanket into the annulus prior to tripping to provide an additional level of safety for the workers by allowing the detection of a nitrogen leak before any H_2S leak.

10.8.5.3 Sample Catcher

Prior to geological sample recovery, the sample catcher shall be purged with either an inert gas or a sweet gas. The sample recovery procedure shall still be considered sour and personnel shall take precautions accordingly. The purged sour gas should be vented into the vapor recovery system.

10.8.6 Tripping Operations—Jointed Pipe

Caution—Opening a valve downstream of the NRV equalizing head once the NRV has been opened can create a hazard if there was pressure trapped under the NRV and the bleed line is not properly secured.

There shall be written procedures for the installation and testing of the NRV equalizing head and safe bleed-off of pressure using a standpipe manifold control valve and the crews are trained in the execution of these procedures.

At an appropriate sample point the UBD supervisor shall confirm that all pressures have been bled off.

A suitably calibrated pressure gauge should be installed between the NRV equalizing head and a downhole isolation valve (DIV). If the pressure below the NRV does not bleed off, the isolation valve should be closed and the pressure build up monitored. An investigation as to whether the pressure build up is a result of an NRV leak from below or a drill string leak shall be conducted.

The preferred method for tripping jointed pipe in a UBD operation depends on the formation pressure, the gas/oil ratio, fluid density and compatibility and the well objectives (why the well is being drilled underbalanced). The methods may be different for tripping out and tripping in. In all cases (IADC Level 1 through Level 5), circulate the hole clean and flow the well to remove all contaminated drilling fluid from the open hole section prior to tripping; leaving uncontaminated formation fluids in the open hole.

10.8.6.1 In an IADC Level 1 Well

Pull out of the hole with the well flowing with gas-lift-assist or allow the well to reach hydrostatic balance with zero surface pressure by the end of trip. With the lift-gas shut off, if surface pressure equals zero utilize, a Venturi jet line rigged up to the flowline to draw vapors off the top of the well prior to opening the RCD to retrieve the BHA. (see GRI *Underbalanced Drilling Manual*, Figure 2-12 for an example of a Venturi jet design.)

On the trip in, when bit re-enters the fluid column the well becomes overbalanced as fluid rises due to drill pipe displacement. Jetting or injection with lift gas may be required to reduce amount of overbalance as the pipe is stripped to bottom. Pipe-light is usually not a concern on an IADC Level 1 well.

If the lift-gas injection equipment has a pressure rating less than MASP underbalanced kickoff operations shall be staged into the well at the appropriate depths so as not to exceed the maximum allowable working pressure of the equipment.

10.8.6.2 *IADC Level 2 wells*. On low-pressure oil wells where pipe-light is not a concern (while the well is flowing), flow the well at controlled rates while stripping pipe out of the hole. A technique using an inline pump should be used to prevent oil spills during tripping and recovery of the BHA when the UBD flow control system is opened. On low-pressure gas wells where pipe-light is not a concern (while the well is flowing), flow the well while stripping pipe out of the hole. A technique using a lubricator above the RCD should be used to mitigate a gas release at surface and enable safe recovery of the BHA at surface when the UBD flow control system is opened.

Equipment and procedures shall be put in place prior to the trip to prevent pipe movement up or down in the event the well must be shut-in during the trip and the potential exist for a pipe-light condition to exist under the shut-in condition.

10.8.6.3 *IADC Level 2 wells*. If the potential for a pipe-light condition exists while flowing the well and tripping pipe in and out of the well, equipment and or procedures shall be in place to enable the pipe to be retrieved and run above the pipe-light depth and to enable safe recovery or running of the BHA when the UBD flow control system is opened. Potential options are to set a chemical plug inside casing, utilize a downhole isolation valve (DIV), snub pipe in and out under pressure, or kill the well by top killing, circulating heavy fluid or by bull-heading fluid into the top of the well.

10.8.6.4 *IADC Level 3, 4 and 5 wells.* Equipment and/or procedures shall be in place to enable the pipe to be retrieved and run above the pipe-light depth and to enable safe recovery or running of the BHA when the UBD flow control system is opened. Options are to set a chemical plug inside casing, utilize a DIV, snub pipe in and out under pressure, or kill the well by top killing, circulating heavy fluid or by bull-heading fluid into the top of the well.

If a DIV is installed, risk assessment and modelling should be conducted to investigate the effects of a dropped object (including drill string) on the closed valve and to ensure adequate dropped object risk mitigation is included in the procedures. For example, a 100-bbl fluid cushion or equivalent surface backpressure is held above the DIV.

11 Site Safety

11.1 Scope

This section addresses the safety considerations and provides minimum standards for site safety during a UBD operation.

11.2 General

11.2.1 UBD operations involve a number of interdependent services and personnel in what is essentially a concurrent drilling and production operation; therefore, training of personnel is critical for a safe operation.

11.2.2 Companies embarking on a UBD project should also recognize that in some areas/locations it is difficult to recruit experienced personnel. A robust plan should be in place for onsite UBD orientation and training in the use of the tools, procedures and communication methods required prior to start of operations.

11.3 Training and Certification

11.3.1 As a minimum requirement, all onsite personnel shall possess a certificate of completion from a training program accredited by the International Association of Drilling Contractors UBO Rig Pass™ Accreditation Program, or its equivalent.

11.3.2 As a minimum requirement, all onsite supervisory personnel shall possess a certificate of completion from a training program accredited by the International Association of Drilling Contractors under its UBO WellCAP ™ [12] Well Control Accreditation Program, or its equivalent.

11.3.3 As a minimum requirement, all onsite supervisory personnel (including UBD supervisors) shall possess a supervisory level certificate of completion from a conventional well control training program accredited by the International Association of Drilling Contractors under its WellCAP™ [12] Well Control Accreditation Program, or its equivalent.

11.3.4 Applicable regulatory authorities and safety management systems of the various companies involved may require additional safety or other training. Refer to Figure A.6 for recommended additional training requirements for onsite personnel.

11.3.5 All training and certification shall be current.

[12] This term is used as an example only, and does not constitute an endorsement of this product by API.

11.4 Onsite Orientation and Safety Meetings

11.4.1 Onsite Orientation Briefings

11.4.1.1 Immediately prior to commencing UBD operations, a pre-job safety meeting and orientation briefing shall be conducted with all personnel on the wellsite. Documentation recording topics discussed and persons attending this meeting shall be kept at the wellsite. The meeting topics should include, but not be limited to:

— a review of the project plan;

— a review of the HAZOP final report to ensure all action items have been formally closed out;

— an overview of the procedures in place for planned and unplanned events;

— an overview of the wellsite map and equipment layout, with hazardous areas and the location of safety equipment identified;

— an overview of the onsite organizational hierarchy and chain of command;

— workers' safety-critical and non-critical roles and related responsibilities;

— communications, including portable zone-rated radios, frequency, etc.;

— wellsite security;

— for sour UBD wells, an overview of the site-specific ERP, specifically addressing alarms, safe muster areas, and search and rescue procedure.

11.4.1.2 The topics covered in this pre-job safety meeting shall be repeated with ALL operations personnel arriving for the first time since UBD operations have commenced. Topics and persons attending shall be appropriately documented.

11.4.1.3 All visitors to the wellsite shall be given a site orientation briefing. Documentation of topics discussed and persons receiving this orientation shall be kept at the wellsite. The orientation topics should include, but not be limited to:

— an overview of the onsite organizational hierarchy and chain of command;

— an overview of the wellsite map and equipment layout, with hazardous areas and the location of safety equipment identified;

— an overview of the site-specific ERP, specifically addressing alarms and safe muster areas;

— an overview of the current and planned operations for the duration of the visit and any associated hazardous areas.

11.4.2 Pre-task Meetings/Briefings

11.4.2.1 Emergency Response Plan Meeting

Immediately prior to commencing critical sour UBD operations, an ERP meeting shall be conducted with ALL personnel with responsibilities under the ERP. Meetings with local residents will be conducted if required by the plan.

11.4.2.2 Pre-task Safety Meetings

A short pre-task meeting shall be conducted with all personnel on the wellsite to review specific equipment and procedures for upcoming operations:

— immediately after each shift or crew change, or

— prior to a significant change in operations (e.g. prior to a stripping/snubbing or tripping), or

— prior to any change in work scope (deviation from the plan or in response to an unplanned event).

11.5 Wellsite Lighting

The lighting at the wellsite shall be sufficient to enable work to be conducted safely and to allow personnel to safely leave the wellsite, initiate emergency shutdown procedures, and perform a rescue if required.

In addition to the standard rig lighting, extra lighting may be required to illuminate all areas where work is being conducted.

11.6 Communications

Prior to drilling into any hydrocarbon-bearing formation, open-channel radio communication is required on the wellsite. All communication devices shall be zone-rated and tuned to the same frequency for concurrent operations and:

— selection of communication devices shall be appropriate for personnel tasks and exposure to equipment;

— the objective is to maintain operational efficiency for concurrent onsite operations.

11.7 Special Considerations: IADC Level 4 or Level 5 Wells

11.7.1 Safety Supervision

Depending on the experience of the crews with respect to a UBD operation, the use of trained safety supervisors should be considered.

On critical sour UBD wells, safety supervisors shall be trained and certified in H_2S safety. Two safety supervisors shall be required on a 24-hour basis, each working no more than a 12-hour shift while on the wellsite.

11.7.2 Site Access Control

Depending on complexity of the operation, and the environmental and industrial sensitivities within the wellsite, trained security officers should be considered.

If deemed necessary, two security officers shall be required on a 24-hour basis, each working no more than a 12-hour shift while on the wellsite, to control access to the drilling location and to maintain a record of the personnel on site.

11.7.3 Onsite Personnel and Visitors

The number of personnel on the wellsite during the UBD operation should be kept to a minimum, and restricted to those directly involved in the operations.

Visitors shall be given an orientation briefing (see 11.4.1.3) before entering the wellsite area. Visitors' time on the wellsite shall be kept as short as possible.

11.7.4 Hydrogen Sulfide Equipment

Prior to drilling into the critical sour zone, adequate air monitoring equipment, breathing-air generating equipment and rescue equipment must be on site, installed, tested, and ready for service. The equipment requirements shall include, but not be limited to, the equipment list in A.2.

11.7.5 Medical Services and Equipment—Special Considerations

11.7.5.1 Access to appropriate medical services should be considered for any operation where the assessed risk of injury to personnel is deemed medium to high. This is especially important during a sour UBD well, in the event a worker is exposed to an H_2S release.

Prior to drilling into the critical sour zone, an industrial First Aid attendant and emergency conveyance vehicle should be on site when emergency medical service (EMS) is greater than 20 minutes surface travel time from the wellsite.

11.7.5.2 Access to supplies included in a burn kit similar to that specified by St. John's Ambulance (see A.4) is especially important during a UBD well, especially where liquid hydrocarbons are used as the drilling fluid or are produced during the UBD operation.

11.7.6 Equipment Placement

To allow safe egress in the event of a gas release, equipment shall be placed in a manner allowing for two routes of egress with consideration given to prevailing wind direction.

11.7.7 Fire Protection

11.7.7.1 Fire Protection Equipment

11.7.7.1.1 The following minimum fire protection equipment, based on the level of flammability risk (refer to Table 16) shall be available on site for underbalanced drilling.

11.7.7.1.2 The risk level of the pumped drilling fluid may be different from that of the produced fluid. The specified fire protection equipment shall be available on site for the highest anticipated risk level (see Table 15).

Table 15—Flammability Hazard Chart

Flammability Risk	Fire Protection Equipment
Low	Four (4) 40-BC type extinguishers
Moderate	Four (4) 40-BC type extinguishers
	50 kg ABC wheel-mounted extinguisher
High	Four (4) 40-BC type extinguishers
	Fire fighting equipment and personnel (see A.3)
	In addition an offshore operation will require deluge systems and foam discharge monitors

Table 16—Risk Categories of Flammable Fluids

Risk Level	Flammability			
	RVP	API	OCFP	CCFP
Low	< 7 kPa	< 50	> 12 ºC	> 12 ºC
Moderate	7 kPa to 14 kPa	> 50	> 0 ºC	> 0 ºC
High	14 kPa	****	< 0 ºC	< 0 ºC

11.7.7.2 Fire-retardant Clothing

All personnel involved in the UBD operation on the wellsite shall wear fire-retardant clothing.

12 Wellsite Supervision

12.1 Scope

This section addresses supervisor qualifications and responsibilities.

12.2 General

UBD experience and training should be of primary consideration in selecting wellsite supervisors. In many operations, the use of a qualified UBD supervisor and/or engineer to assist and advise the wellsite supervisor has been effectively used.

12.3 Responsibilities

12.3.1 Operator's Representative

12.3.1.1 The operator shall delegate a primary wellsite supervisor as having overall control in the chain of command.

12.3.1.2 The primary wellsite supervisor has the overall responsibility to the operator for the well and for compliance with all regulations relating to the operation of the well.

12.3.1.3 The primary wellsite supervisor shall establish a chain of command and a line of communication at the wellsite.

12.3.1.4 The primary wellsite supervisor shall be on site at all times.

12.3.2 Contractors' Representatives

All contractors' representatives shall be responsible to the operator's representative for the safe operation of their equipment/services during the drilling of the well. This relationship provides for a single chain of command for the well operation.

Contractors' representatives shall be responsible to their companies for their equipment and crews, and for compliance with all regulations relating to the operation of their equipment.

12.3.3 Cooperation

The day-to-day operations on a wellsite require cooperation between the contractor and operator representatives. However, the responsibility for supervision of the well operation lies with the operator's representative.

12.4 Supervision for IADC Level 4 and Level 5 Wells

12.4.1 Staffing Levels

Crew staffing levels shall be adequate to ensure that the roles and responsibilities of the operational plan and the ERP are provided for.

12.4.1.1 Minimum Qualifications

Each crew member shall be competent to fully handle his/her individual responsibilities and to fully understand his/her responsibilities.

12.4.1.2 Wellsite Supervisors

12.4.1.2.1 A 24-hour operation will require two wellsite supervisors, each working 12-hour shifts. One of these shall be designated as the primary wellsite supervisor by the operator (see 12.4.1.4).

12.4.1.2.2 The rig manager must be available to the operation on a 24-hour basis.

12.4.1.2.3 Special safety supervision shall be required on a 24-hour basis.

12.4.1.3 Operator Supervisors

The demands placed on supervisors (i.e. superintendents) of IADC Level 4 or Level 5 UBD operations are very high due to the inherent complex nature of the operation, the increased risk factor, and the larger numbers of personnel involved. Supervisors shall, therefore, have the technical, organizational and operational competence to meet these demands effectively.

12.4.1.4 Operator's Primary Wellsite Supervisor

12.4.1.4.1 The primary wellsite supervisors shall have documented previous experience in a wellsite supervisory role on the same IADC well classification level wells. This will help to ensure that the primary wellsite supervisor is knowledgeable of current industry practices.

12.4.1.4.2 On critical sour UBD wells, the primary wellsite supervisor shall have documented previous experience on sour well operations.

12.4.1.5 Secondary Wellsite Supervisors

The secondary wellsite supervisors shall have documented previous experience on an underbalanced well or as a primary wellsite supervisor on a non-UBD operation.

Annex A

A.1 Casing Integrity Assessment Process

(See IRP 6.)

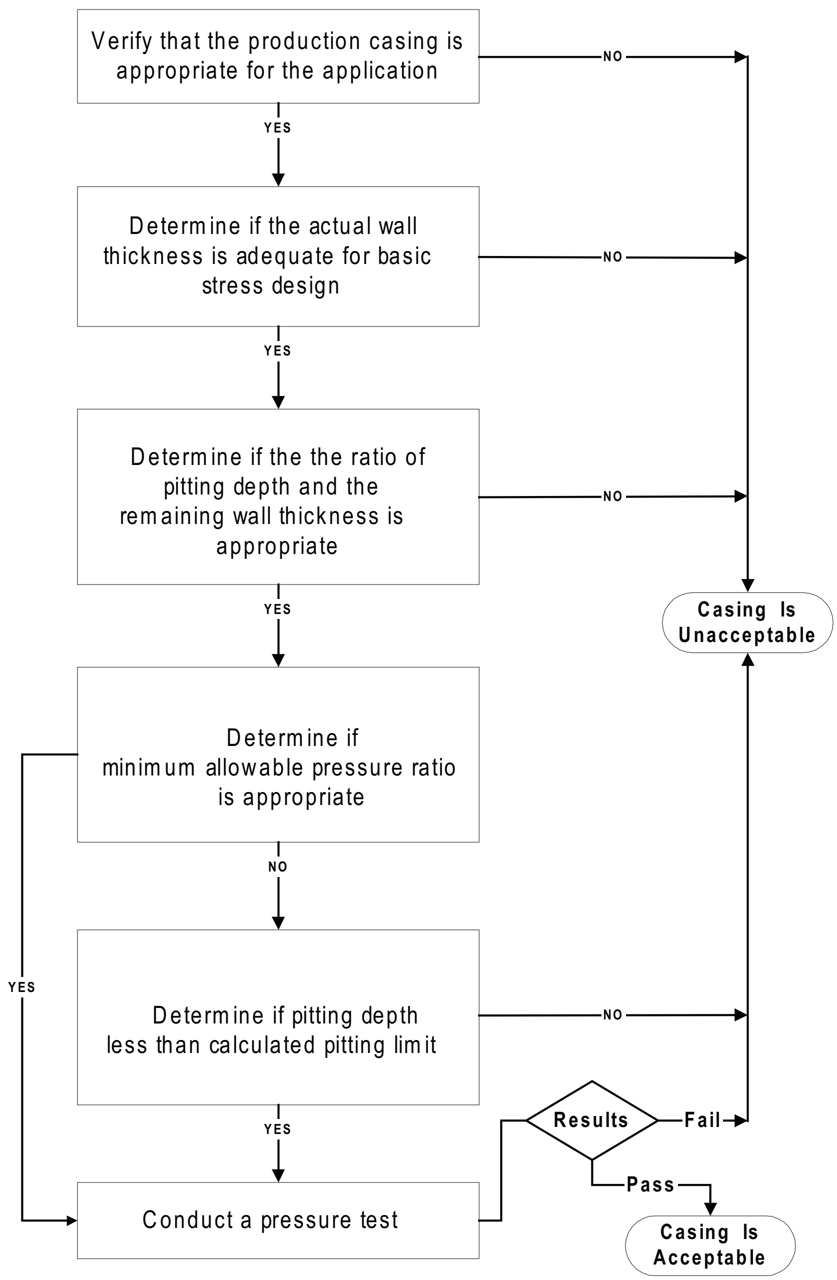

Figure A.1—Casing Integrity Assessment Flowchart

--`,,`````,`,`,``,,``,,`,`````,-`-`,,`,,`,`,,`---

A.2 Breathing Air/Gas Detection Equipment

In the absence of applicable regulations and or operating company policy, the minimum basic equipment for a compressed breathing-air generation and gas detection system, if required, should include (see IRP 6):

— 2400 ft^3 (67.96 m^3) breathing air supply;

— 2× two-stage high pressure regulators;

— 2× six-outlet air header assemblies;

— 8× supplied air breathing apparatus c/w egress cylinders;

— 8× self-contained breathing apparatus;

— 8× spare 45 ft^3 (1.27 m^3) compressed breathing air cylinders;

— 2× 30 m (98.42 ft) x 10 mm I.D. special hose c/w quick couplers.;

— 6× 30 m (98.42 ft) x 6 mm I.D. special hose c/w quick couplers;

— 1 H_2S warning sign;

— 2× wind direction indicators;

— 1 multi-gas detector c/w H_2S detector tubes;

— 2× continuous H_2S/LEL/O portable monitors;

— 1 continuous H_2S/LEL gas detection system complete with alarms and 4× detection sensors.

A.3 Fire Fighting Equipment

In the absence of applicable regulations and or operating company policy, consideration should be given to include the following as minimum fire fighting requirements (see IRP 6), especially where liquid hydrocarbons are used as the drilling fluid or are produced during the UBD operation:

a) Continuous foam unit:

— 0.475-m^3 (125-gal) ATC foam concentrate;

— 680-kg (1500-lb) Purple "K" Dry Chemical System c/w 30-m (98.42-ft) discharge hose;

— 1.89-m^3/min (500-gpm) certified centrifugal fire pump c/w one 65-mm discharge port, two 38-mm (1.5-in.) discharge ports, one 101.6-mm (4-in.) suction port.

b) Water supply:

— 16 m^3 (100 bbl) water.

c) Foam application rating:

— based on the NFPA Standard 11 application rate of 6.5 $l/min/m^2$ for non-polar hydrocarbons.

d) Personal protective clothing:

— personal protective clothing shall be provided in accordance with a suitable and sufficient risk assessment (see 11.7.7.1.2).

A.4 Burn Kit e.g. St. John's Ambulance

In the absence of applicable regulations and or operating company policy, consideration should be given to include a burn kit (see IRP 6) as part of the first aid supplies available on site, especially where liquid hydrocarbons are used as the drilling fluid or are produced during the UBD operation:

— 1 fire blanket 91 cm × 76 cm (3 ft x 2.5 ft);

— 2× dressing 20 cm × 46 cm (0.66 ft x 1.52 ft);

— 2× dressing 10 cm × 40.5 cm (0.33 ft x 1.33 ft);

— 1 face mask 30.5 cm × 40.5 cm (1.0 ft x 1.33 ft);

— 4× conforming bandage;

— 1 pair of scissors;

— 1 burn kit storage container.

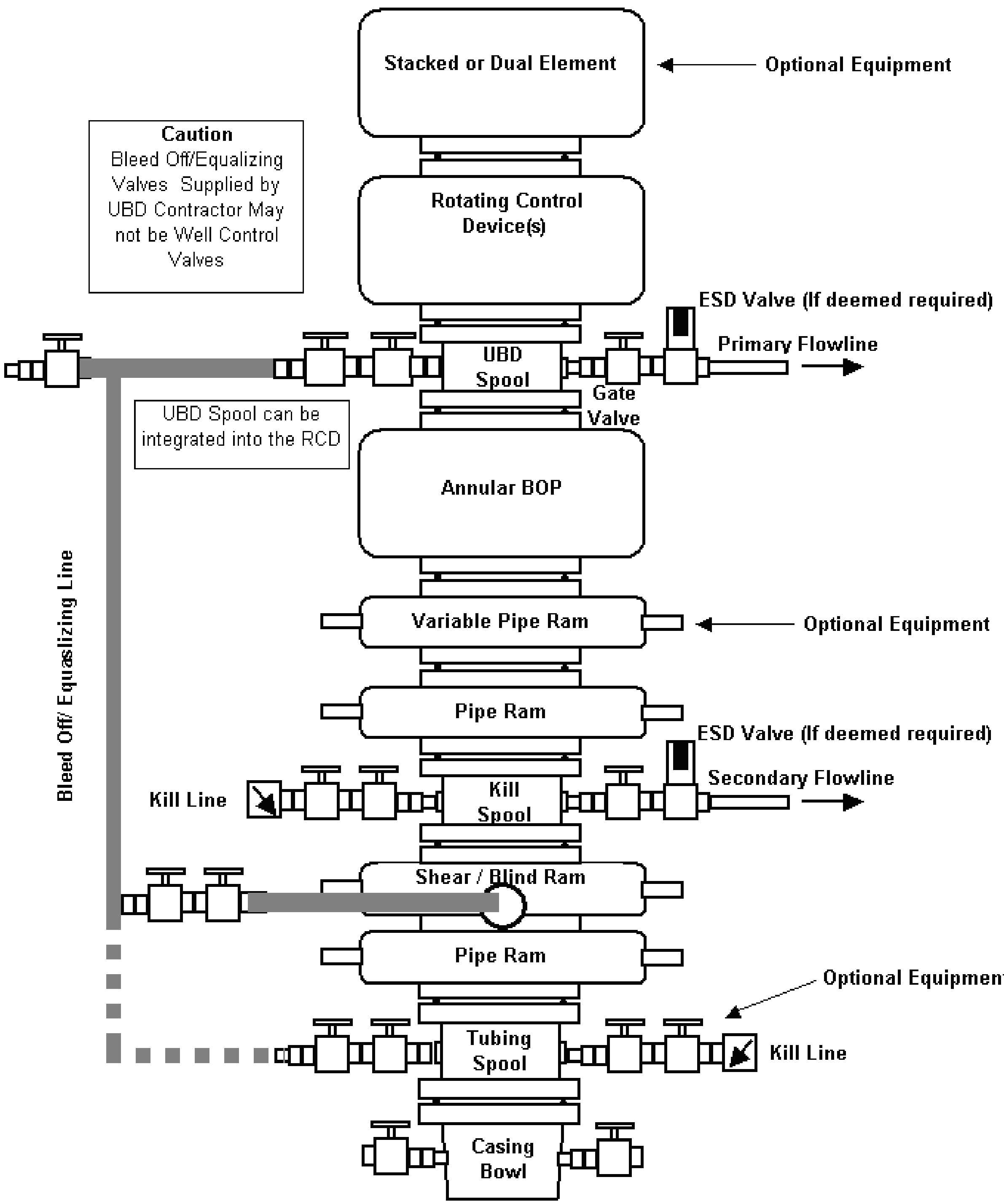

Figure A.2—Example UBD BOP Stack Configuration—Gas Well

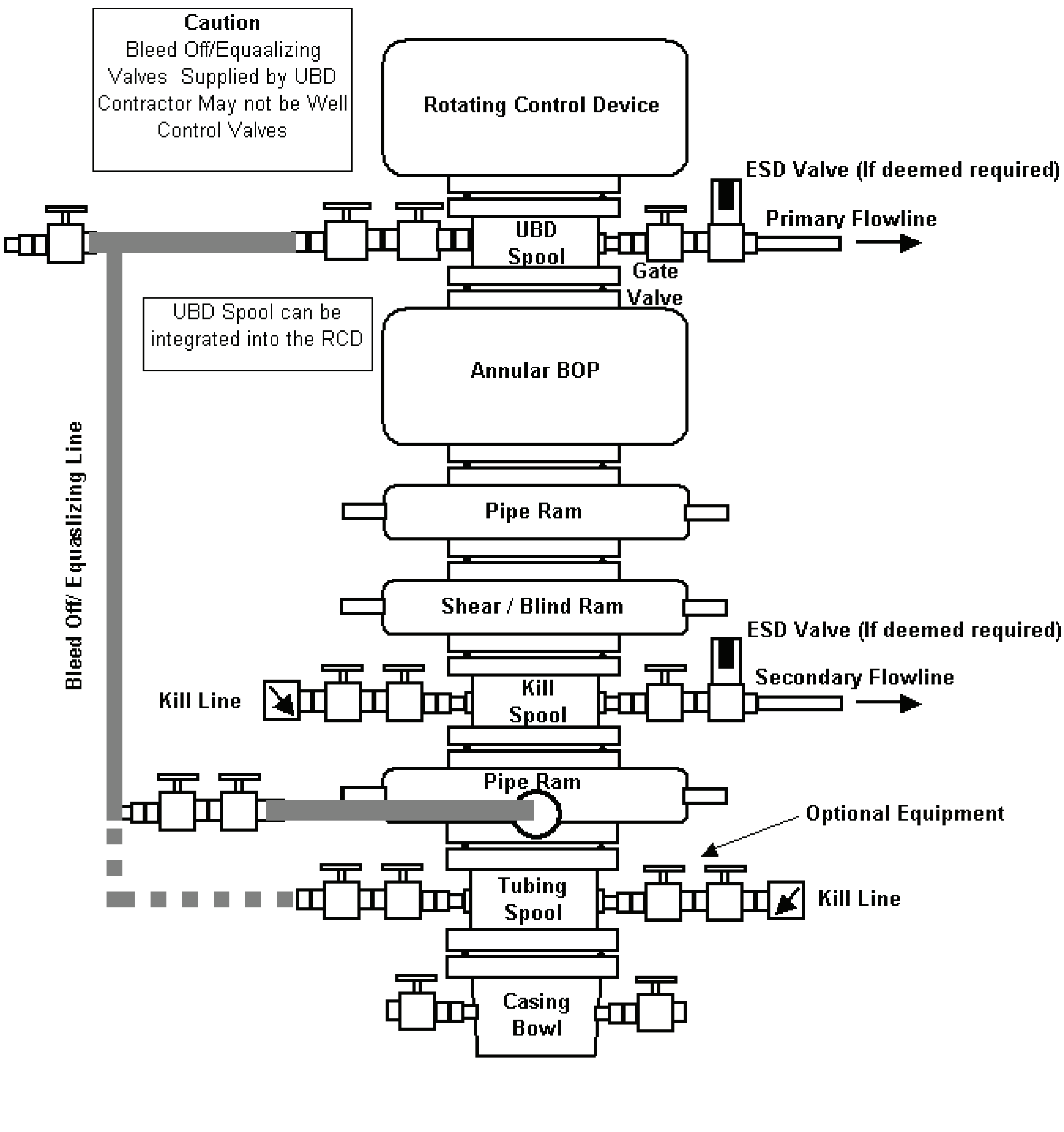

Figure A.3—Example UBD BOP Stack Configuration—Oil Well

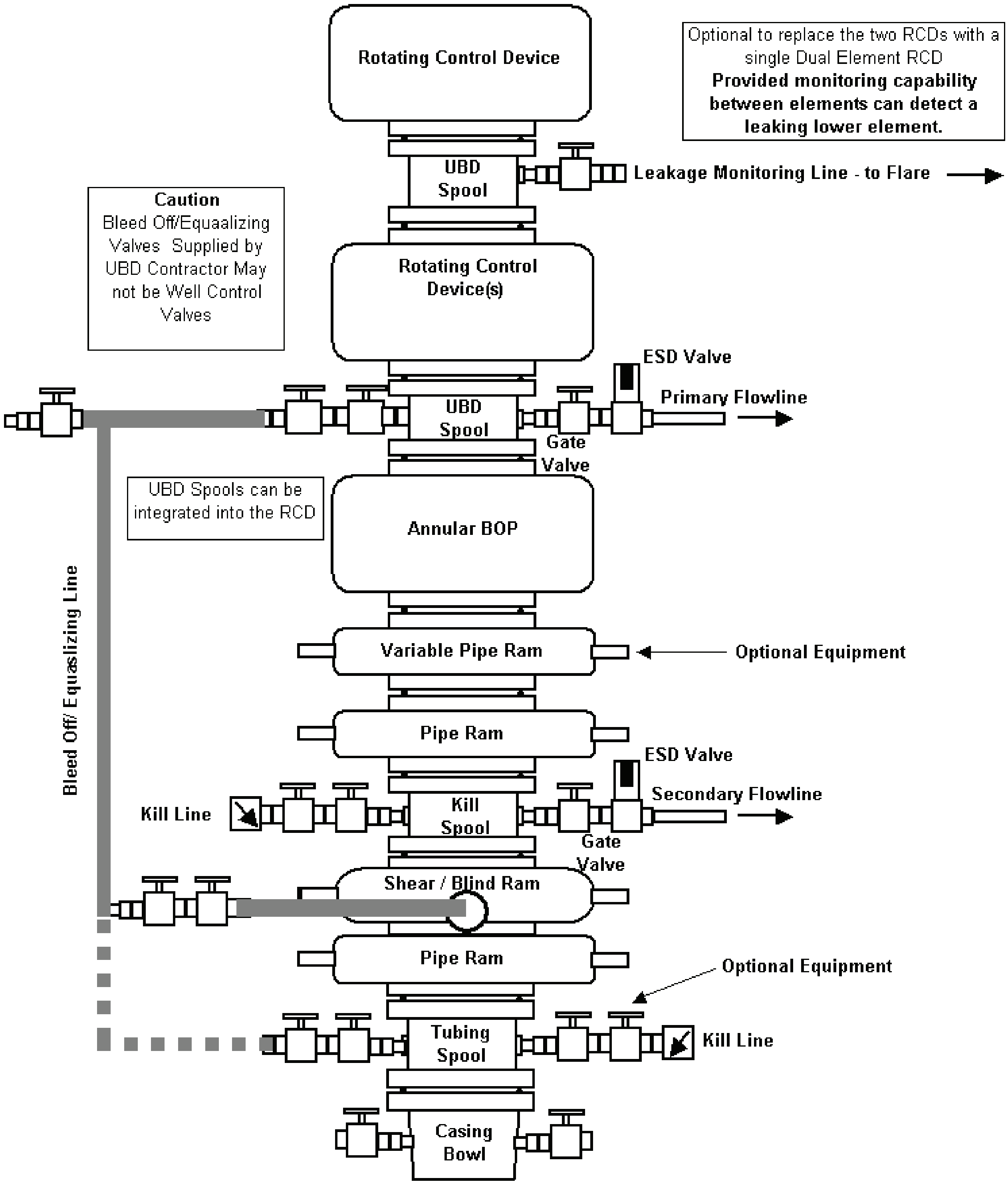

Figure A.4—Example UBD BOP Stack Configuration—Critical Sour Well

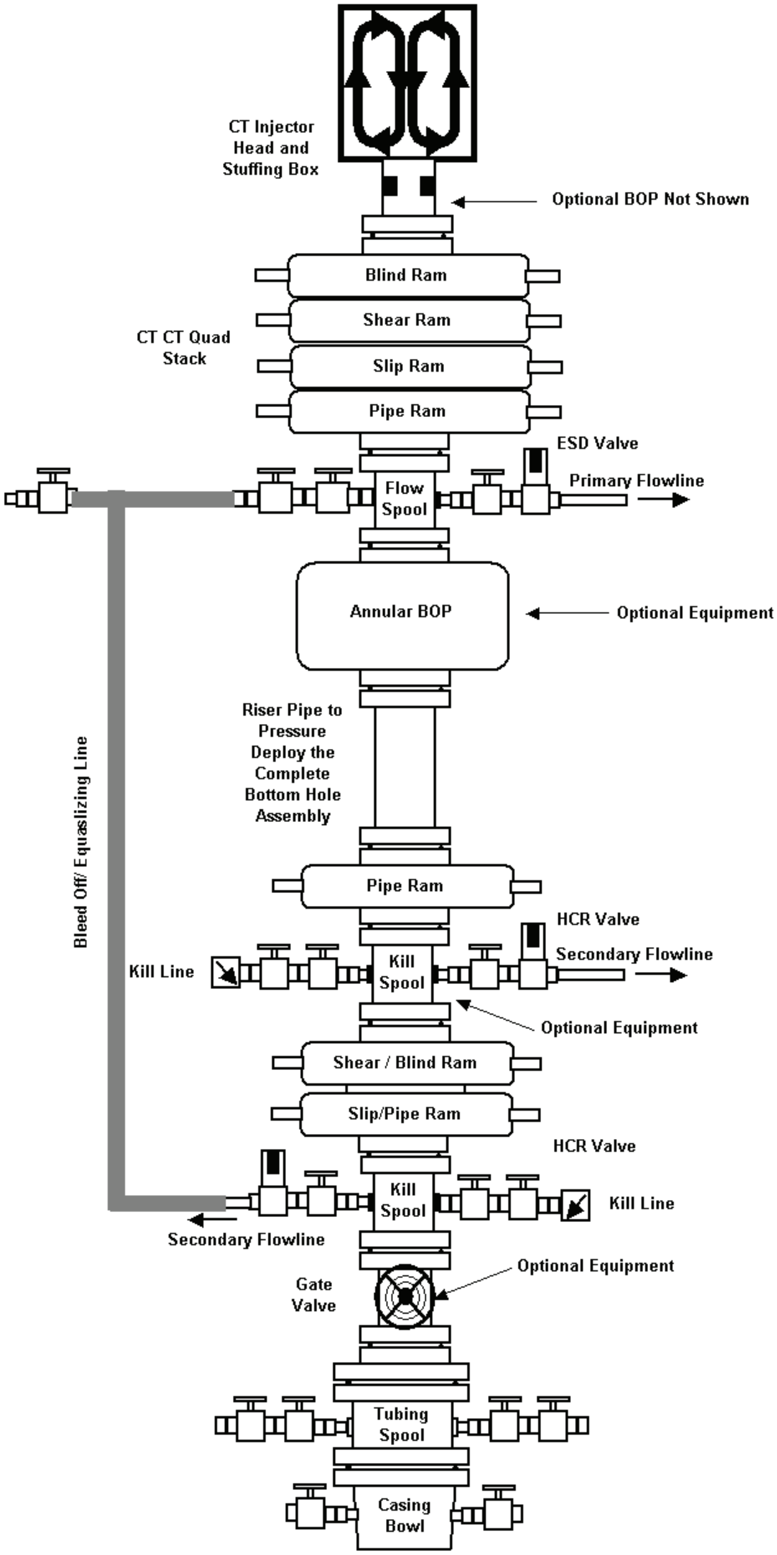

Figure A.5—Example UBD Coiled Tubing (CT) BOP Stack Configuration—Critical Sour Well

Training Program	Oil Company Supervisors		Drilling Rig		Service Rig		Coiled Tubing Drilling Rig			Snubbing Contractor		UBO Services Contractor			Miscellaneous Onsite Services			
	Drilling	Well Services	Rig Manager	Crews	Rig Manager	Crews	Project Supervisor	Shift Supervisor	Crews	Supervisor	Crews	Project Supervisor	Shift Supervisor	Crews	Safety Supervisor	Mud Engineer	Truck Drivers	Other* Personnel
UBO RIGPASS ® Safety Orientation	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
UBO WELLCAP ® Well Control	✓	✓	✓	3	✓	3	✓	✓				✓	✓					
Conventional First Line Well Control	✓	✓	✓	3	✓	3		✓				✓	✓					
Well Service Blowout Prevention		✓			✓	3	✓	✓		✓								
Confined Space	6	6	✓	2	✓	2	6	6	2	✓	✓	6	6	2	✓		5	
First Aid	✓	✓	✓	1	✓	1		✓	1	✓	1		✓	1	✓			
Transportation of Dangerous Goods	✓	✓	✓		✓		✓	✓		✓		✓	✓		✓	✓	✓	
Workplace Hazardous Material Information	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
H_2S**	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Rescue**	✓	✓	✓	4	✓	2	✓	✓	2	✓		✓	✓		✓			

* Not involved in the Day-to-Day operations

** UBD on Sour Gas or Oil Wells

1 - At least one crew member

2 - At least two crew members

3 - The Driller only

4 - The Driller and the Assistant Driller

5 - Tanker and Vacuum truck drivers only

6 - Code of Conduct only (Pre-entry)

Figure A.6—UBD Operations—Training Matrix (EXAMPLE)

energy API

2008 Publications Order Form

Effective January 1, 2008.
API Members receive a 30% discount where applicable.
The member discount does not apply to purchases made for the purpose of resale or for incorporation into commercial products, training courses, workshops, or other commercial enterprises.

Available through IHS:

Phone Orders: **1-800-854-7179** (Toll-free in the U.S. and Canada)
303-397-7956 (Local and International)
Fax Orders: **303-397-2740**
Online Orders: **global.ihs.com**

Date: ______________________

☐ **API Member** (Check if Yes)

Invoice To (❏ Check here if same as "Ship To")

Name:
Title:
Company:
Department:
Address:

City: State/Province:
Zip/Postal Code: Country:
Telephone:
Fax:
Email:

Ship To (UPS will not deliver to a P.O. Box)

Name:
Title:
Company:
Department:
Address:

City: State/Province:
Zip/Postal Code: Country:
Telephone:
Fax:
Email:

Quantity	Title	SO★	Unit Price	Total
	Spec 16A/ISO 13533, Drill-through Equipment		$155.00	
	Spec 16D, Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment		$166.00	
	RP 53, Blowout Prevention Equipment Systems for Drilling Operations		$124.00	

❏ Payment Enclosed ❏ P.O. No. (Enclose Copy) ____________

❏ Charge My IHS Account No. ____________

❏ VISA ❏ MasterCard ❏ American Express
❏ Diners Club ❏ Discover

Credit Card No.:
Print Name (As It Appears on Card):
Expiration Date:
Signature:

Subtotal	
Applicable Sales Tax (see below)	
Rush Shipping Fee (see below)	
Shipping and Handling (see below)	
Total (in U.S. Dollars)	

★ To be placed on Standing Order for future editions of this publication, place a check mark in the SO column and sign here:

Pricing and availability subject to change without notice.

Mail Orders – Payment by check or money order in U.S. dollars is required except for established accounts. State and local taxes, $10 processing fee, and 5% shipping must be added. Send mail orders to: **API Publications, IHS, 15 Inverness Way East, c/o Retail Sales, Englewood, CO 80112-5776, USA.**

Purchase Orders – Purchase orders are accepted from established accounts. Invoice will include actual freight cost, a $10 processing fee, plus state and local taxes.

Telephone Orders – If ordering by telephone, a $10 processing fee and actual freight costs will be added to the order.

Sales Tax – All U.S. purchases must include applicable state and local sales tax. Customers claiming tax-exempt status must provide IHS with a copy of their exemption certificate.

Shipping (U.S. Orders) – Orders shipped within the U.S. are sent via traceable means. Most orders are shipped the same day. Subscription updates are sent by First-Class Mail. Other options, including next-day service, air service, and fax transmission are available at additional cost. Call 1-800-854-7179 for more information.

Shipping (International Orders) – Standard international shipping is by air express courier service. Subscription updates are sent by World Mail. Normal delivery is 3-4 days from shipping date.

Rush Shipping Fee – Next Day Delivery orders charge is $20 in addition to the carrier charges. Next Day Delivery orders must be placed by 2:00 p.m. MST to ensure overnight delivery.

Returns – All returns must be pre-approved by calling the IHS Customer Service Department at 1-800-624-3974 for information and assistance. There may be a 15% restocking fee. Special order items, electronic documents, and age-dated materials are non-returnable.

1220 L Street, NW
Washington, DC 20005-4070
USA

202.682.8000

Additional copies are available through IHS
Phone Orders: 1-800-854-7179 (Toll-free in the U.S. and Canada)
303-397-7956 (Local and International)
Fax Orders: 303-397-2740
Online Orders: global.ihs.com

Information about API Publications, Programs and Services
is available on the web at www.api.org

Product No. G92U01