Drilling and Well Operations Practice

E&P Defined Operating Practice

operating
management
system

GP10-00

SIS 103936800

Contents

Contents (cont'd)

PART B **Significant Risk Practices with ETPs**

Contents (cont'd)

Authorisation for Issue

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Amendment Summary

Issue No	Date	Description
Issue 1	October 2008	First issue of document.

Part 'A'

Standard Practices

Section 1
Introduction

1.1 Purpose

This document and the related Engineering Technical Practices (ETPs) replace the BP Drilling and Well Operations Policy (BPA-D-001). This document is a **Segment Defined Operating Practice** and is applicable in all areas of the E&P Segment of BP. The ETPs referred to in this document are available in Category 10 of the BP Group ETP Library on the BP Intranet.

- ETP Library can be found at: http://etplib.bpweb.bp.com

The online document is to be considered the master version, containing the most up to date information. Printed copies of this practice and printable copies downloaded from the website should be treated as "Uncontrolled".

Constructive comments and suggestions for update and revision in regard to the practice are encouraged and welcomed. The feedback will be collated via the above website for formal consideration by Functional Leadership and Segment Technical Authorities.

This document is a summary of the key elements of the DC&W Engineering Technical Practices. It also encompasses a number of standard practices that are not the subject of the ETPs. Where any potential conflict or lack of detail exists, the ETP has primacy. It is important to note that the ETPs may contain important requirements over and above those summarised in this document, and therefore conformance solely with this document does not ensure conformance with the ETPs or STPs derived from those ETPs.

This document contains the practices that have been agreed by BP management as current and relevant for drilling and well operations. These practices are considered critical for:

- Achieving the company's goals of no accidents, no harm to people and no damage to the environment
- Conformance with BP's OMS Framework & Group Essentials
- Supporting implementation of the Group Defined Practice for Integrity Management (IM) GDP 5.0-0001
- Prevention of incidents that would have a high negative economic or reputational impact

1.2 General

BP is committed to conducting its business in a manner which ensures that wells are designed, drilled, completed and maintained to high and consistent standards. BP's drilling and well operations practices are defined in the Engineering Technical Practices (ETPs) and this document. BP will comply with all relevant laws and regulations, and will be sensitive to the balanced economic and environmental needs of the community. Sound engineering judgement and governmental regulations may require that operations be carried out to standards exceeding these requirements.

To ensure that we meet these objectives, BP has adopted the Operating Management System (OMS) which defines our expectations for identifying and managing safety, health, environmental and operational risks. Strategic Performance Units (SPUs) are responsible for ensuring that their management and control systems satisfy the requirements contained in their Local Operating Management System (LOMS), comprising;

- OMS Framework
- Group Defined Practices
- Group Recommended Practices
- Segment/SPU Defined Practices
- Segment /SPU Recommended Practices
- Local Site Operating Procedures and Practices

SPUs are responsible for integrating the drilling and well operations practice requirements with the other elements of the corporate governance framework, such as supply chain management, process safety and integrity, and legal policy requirements.

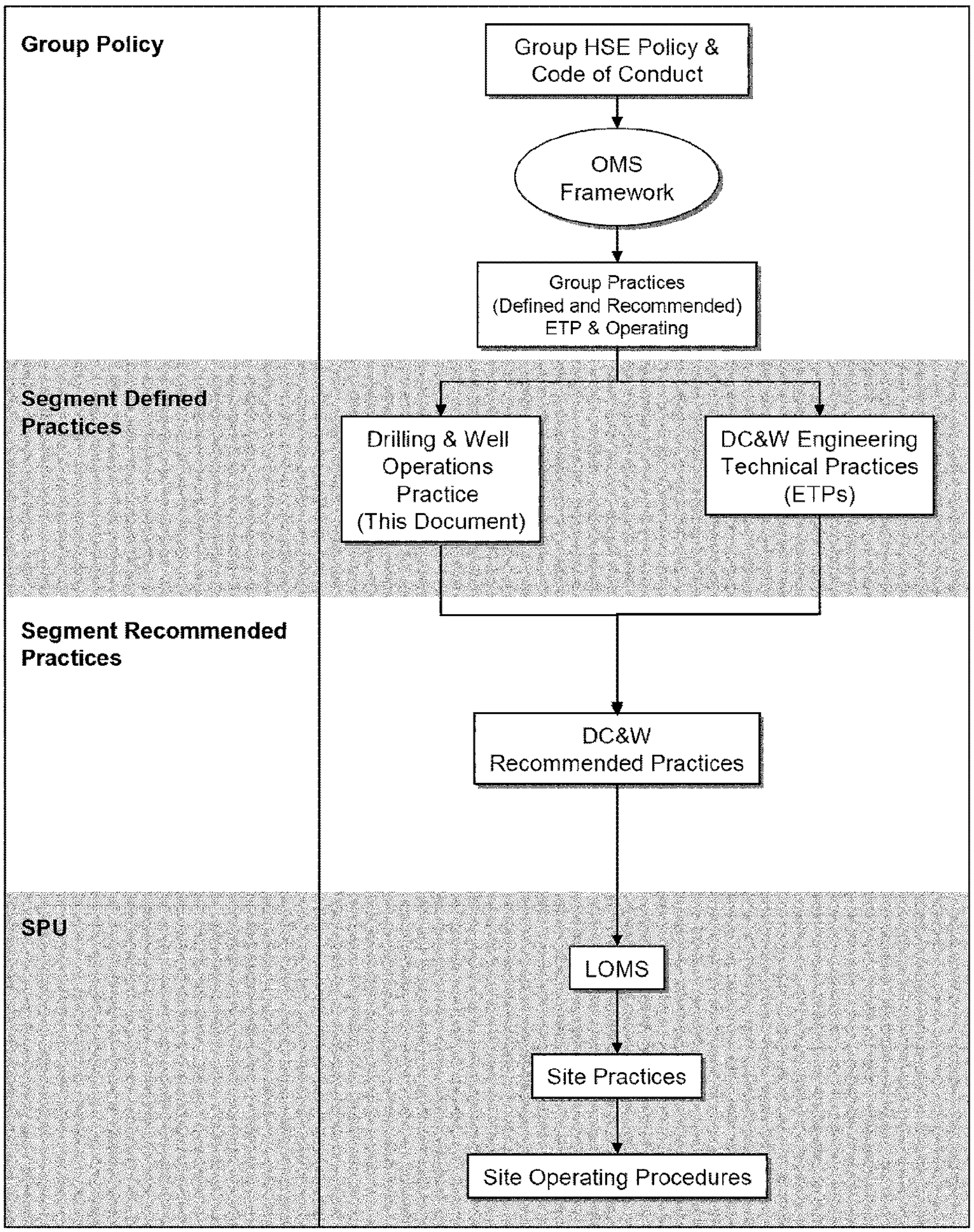


Figure 1.1 Drilling and Well Operations Practice in BP Operating Management System Hierarchy

1.3 Application

This practice applies to all drilling and well operations comprising well construction, drilling, testing, completion, workover, well operations and intervention activities related to wells performed under the control or supervision of BP, or on behalf of BP as the operator. The practice shall form part of the contractual relationship between BP and its service providers.

1.4 Implementation

All staff and contractor personnel engaged in managing BP drilling and well operations shall be knowledgeable of all elements of this practice and associated ETPs and are responsible for conformance.

1.5 Procedure for Revision

The Drilling and Well Operations Practice shall be updated or revised under the stewardship of the Technology Vice President (Issue Authority). A team appointed by the Technology Vice President shall meet as required to discuss proposed amendments to ETPs and DWOP. Once consensus is reached and the changes are ratified by the Discipline Vice Presidents, they will be authorised for issue by the Technology Vice President. Addenda 1 and 2 contain the Practice Amendment/Revision Flow Map and Process.

1.6 Use of Language

In this Practice, the following words when used in context of actions by BP or others, have the specific meanings:

"Shall" is used where a provision is mandated and is a minimum requirement.

"Should" is used where a provision is preferred or recommended.

1.7 Exception to Practice Statements

Deviations from the Drilling and Well Operations Practice and ETPs shall only be considered in exceptional circumstances and in accordance with the table below.

Deviation should be requested by documenting the reasons why the deviation is being sought and the implications contravention of the practice may have for BP. Authority to approve a deviation, temporary or permanent, will depend on the language that is contained within the specific requirement. A deviation may be requested and approved either for a single well or a number of wells in the same area. A deviation shall not be assumed to apply to other situations unless a similar specific deviation has been sought and approved. In critical situations, urgent verbal approval shall be backed up with written confirmation as soon as practicable.

DWOP	Deviation Required		Deviation Authority	
	Temporary	**Permanent (subject to annual review)**	**Shall**	**Should**
Part A Standard Practice Requirements	Standard Deviation Process	Standard Deviation Process	Wells EA	Wells EA Can be delegated to Wells TL
Part B Significant Risk Requirements – with ETP	Standard Deviation Process	Develop STP	Wells EA SETA endorsement required	Wells EA SPU TA endorsement required

The Practice Deviation Process Flow Map is shown in Addendum 3. The format for practice deviation includes the following items:

- Which practice/requirement is to be contravened
- The reason for the request
- The proposed departure from practice
- Additional risks so incurred and actions taken to minimise those risks
- The duration of the deviation
- Documented approval

Note that there may be minor variations on the exact process due to local management structure and legislative environment. Clarification should be sought from the appropriate Vice President if required.

An approved copy of the deviation shall be retained and accessible within the SPU filing system.

1.8 Conformance

Periodic audits shall be undertaken in order to ensure conformance with this practice and the associated ETPs. It is acceptable to incorporate this requirement within HSSE audits, other audits, and incident investigations.

It is the responsibility of all involved in drilling and well operations to utilise prudent judgement and seek guidance from line management when there is a concern that conformance with any practice statement increases the risk of an incident.

Section 2
General

2.1 All drilling and well operations shall be planned and performed in compliance with applicable BP and Strategic Performance Unit (SPU) policies. These may include, but are not limited to, policies on health, safety and the environment; ethical conduct; employees; relationships; and control and finance.

2.2 All drilling and well operations shall be planned and performed in compliance with all applicable legislation and regulations. All applicable governmental permits shall be obtained (air quality, annular injection, drilling, etc) prior to the commencement of operations.

2.3 Priorities for safety when planning and undertaking drilling and well operations shall be, in order of importance:

1. Personnel.
2. Environment.
3. The installation.
4. Reservoir integrity.
5. Well delivery.

2.4 Clear roles, responsibilities and accountabilities shall be established for all positions within the drilling and well operations organisations.

2.5 A well handover system formalising the transfer of responsibility for the control of a well between different organisational units, and that documents well conditions, shall be in place.

2.6 Transportation services in support of drilling and well operations shall be in accordance with the relevant SPU and BP policies.

2.7 Detailed policy statements are contained elsewhere within this document for specific activities. If an ETP is referenced then the ETP is the policy document, if no ETP is referenced then this is the policy document.

2.8 Detailed requirements for certain specialised activities, such as underbalanced drilling, air drilling, coiled tubing drilling, snubbing and certain developing technologies are specifically not included in this practice. Wells teams shall consider such specialised activities in context with the practices, and shall not be undertaken without a thorough review of industry experience and BP best practice and a detailed external review of the planned operations and contingencies after thorough risk assessment.

Section 3
HSSE & Risk Management

3.1 General Requirements

3.1.1 All staff and contract personnel involved in the management and supervision of drilling and well operations for BP shall be knowledgeable of the Drilling and Well Operations Practice and associated ETPs.

3.1.2 Everyone involved in BP's drilling and well operations at the wellsite shall be knowledgeable in, and comply with, the relevant safety management system which shall be defined as part of the contractual relationship between BP and the primary contractors. The relevant safety management system will incorporate, or be supplemented to address, the requirements of the OMS Framework.

3.1.3 The contractors' safety management system shall incorporate a behaviour-based safety observation programme, task-based risk assessment, job safe analysis, toolbox talks and inspection and audit programmes, including appropriate action-tracking processes, covering all aspects of the rig and well equipment, systems and personnel training and competencies.

3.1.4 Designated company representatives at every wellsite, whether BP employees, consultants or contractors' personnel employed in the capacity of company representatives, are accountable for the application of the Drilling and Well Operations Practice and the relevant safety management system.

3.1.5 All drilling and well operations safety and integrity management accidents, incidents and significant near misses shall be investigated to determine the root causes and identify actions that will prevent a recurrence.

3.1.6 Designated company representatives are accountable for the execution of the approved drilling and well operations programmes in compliance with BP's health, safety, security and environmental (HSSE) requirements.

3.1.7 Designated company representatives and key third-party service contractors should participate, as appropriate, in the primary contractor's routine safety meetings.

3.1.8 Designated company representatives shall have an up-to-date HSSE training record and documented personal safety objectives.

3.1.9 Incident response plans shall be maintained at every wellsite, and emergency drills shall be regularly conducted and reported. These plans should address the availability of a means of quickly evacuating injured personnel at all drilling and well operations sites.

3.1.10 Every SPU shall have standards in place addressing critical elements of drilling and well operations work including but not limited to standards of HSSE leadership, HSSE support, equipment, audit, safety critical systems and dropped objects prevention.

3.1.11 Specialist BP and contractor HSSE resources should be available at the wellsite, as required, to effectively support and assure compliance with the safety management system and the environmental and waste management systems and participate in incident investigations.

3.1.12 Regular audits of critical elements of the safety management system shall be conducted.

3.1.13 Temporary and permanent changes to personnel, systems, procedures, programmes, safety critical data, equipment, facilities, materials or substances should be made using the management of change process.

3.1.14 All staff and contractor personnel shall adhere to the BP Driving Standard when travelling in vehicles on BP company business.

3.2 Workplace Environment

3.2.1 Lighting systems shall be installed to provide illumination levels adequate for safe completion of tasks performed in that working area per GP12-30. All safety egress paths and assembly areas shall be provided with emergency lighting.

3.2.2 Exposures over a working lifetime should be kept below 80 dBA daily personal noise exposure (LEP,t) to provide full protection from hearing loss due to noise at work (refer to GP14-01).

3.2.3 Controls shall be in place to protect people who use high vibration tools on a regular or prolonged basis from damage to their hands and arms. All tools and equipment used at the wellsite shall be designed to minimise vibration levels to as low as reasonably practicable.

3.2.4 The engineering complexities of mechanised and automated systems shall be fully evaluated on the basis of risk assessment and managed through effective development and application of rigorous inspection, maintenance and operating procedures, and personnel competencies.

3.2.5 Means shall exist to control exposure to airborne hazards, such as dust, gases and vapours, and stressful thermal environments. These may include initial and repeat assessments of the workplace, engineering controls, administrative controls and personal protective equipment provided by the contractor.

3.2.6 The permit to work system shall be employed to control the handling of explosives and radioactive materials.

Personnel who may be exposed to hazardous materials shall be made aware of the hazards and provided with training to manage the risks of exposure, the limitations of and proper use of personal protective equipment, other precautions to be taken, emergency procedures to be followed and any required additional measures such as exposure monitoring.

3.3 Workplace Practices

3.3.1 All risks shall be managed to a level, which is as low as reasonably practicable. Risk management at the wellsite shall include the HSSE issues arising from the selection of resources, the design and operation of working systems, the control and disposal of waste and the delivery of services.

3.3.2 Manriding is a safety critical activity. Routine manriding operations shall not be permitted on BP wellsites. Manriding shall only take place under the permit to work system after a full risk assessment has been conducted. Any permit for manriding operations shall be authorised by the senior wellsite contractor's representative.

The work shall be performed under the direct control of the supervisor in charge of the area. All personnel conducting and supervising manriding operations shall be trained and assessed as competent for the work. All equipment used in manriding operations shall incorporate appropriate safety features, be maintained as required by the manufacturer, be upgraded as required by manufacturers' product bulletins and be inspected prior to and after the work.

3.3.3 Excessive working hours leads to fatigue and impairment of mental alertness. Each SPU shall have a work time standard in place which describes normal shift pattern rotation schedules, routine work periods, control process and contingency arrangements to deal with the occasional circumstances when the standard cannot be complied with.

Personnel engaged in BP's drilling and well operations shall not work in excess of 16 hours during a 24-hour period nor 28 days at the wellsite during a 42-day period without the written authority of the designated company representative. Travel arrangements and pre-arrival work time demands shall be considered as part of the work time control process.

3.3.4 Dropped objects prevention at the wellsite shall be a key element of the contractor's safety management system. Dropped objects standards and controls shall be in place at each facility to raise awareness, define secondary fastening requirements, specify inspection protocols and manage key risks such as control of tools and equipment taken aloft.

3.3.5 All lifting operations shall be planned and properly supervised consistent with the safety management system. A risk assessment or job safe analysis shall be conducted prior to each job and risks shall be eliminated or properly controlled. Detailed standards for lifting activities shall be in place and complied with at every wellsite. Crane operations shall only be conducted under the direct control of a banksman who shall not otherwise be involved in the lifting operation.

Fixed and mobile cranes and integrated protective systems shall be maintained in accordance with the manufacturer's recommendations. Lifting gear and lifting appliances shall be certified and documented prior to use. Hand-spliced wires and slings are not permitted.

3.3.6 Primary drilling, workover and well operations contractors shall have a maintenance management system in place for their equipment. All safety critical equipment shall be included in the maintenance management system, including electrical equipment for use in hazardous areas, load-bearing, lifting, hoisting, pressure containing equipment and protective systems. The system shall be rigorously applied and any overdue items shall be reported to contractors' and operators' senior site representatives on a regular basis.

Third-party equipment on hire at the wellsite for a period in excess of 3-months shall be subject to a formal system of maintenance management. Equipment on short-term hire at the wellsite shall be subject to formal maintenance and inspection checks prior to transport to the wellsite.

3.4 Risk Management

3.4.1 All D&C operations shall follow a documented and auditable risk management process to include identification, assessment, prioritization and action. The process will include all risks with either an HSSE or significant financial impact.

3.4.2 The risk process shall be in conformance with the Group Defined Operating Practice *Assessment, Prioritization and Management of Risk* (GDP 31-00-01) and this conformance shall be documented.

3.4.3 The recommended tool for documenting and managing D&C risks is the web based BP Risk Assessment Tool (RAT):

http://projects.bpweb.bp.com/bprat/firsttime.asp.

Where access to RAT is impractical, the Excel-based 'Common Process Risk Register' may be used. Versions 10 and later of this tool meet the reporting requirements of GDP 31-00-01.

Section 4
Planning, Materials and Services

4.1 All SPUs shall adopt Drilling and Completions Common Process (Drilling Value Assurance, Right Scoping, No Drilling Surprises and Technical Limit) as the standard methodology for well planning and execution.

4.2 All drilling and well operations shall have approved plans to cover emergency management, spill contingency and blowout response. These plans shall be specifically designed for application in the local environmental and operating conditions.

4.3 A well programme shall be in place and adhered to for all drilling and well operations. Well programmes shall have the appropriate level of approval.

4.4 Any significant changes to a well programme shall be documented and approved via a formal management of change (MOC) process which includes those on the original approval list.

4.5 All equipment, materials and services shall be fit for the purpose intended and in compliance with local legislative, BP, and industry (eg API, NACE, ANSI, ASME, ISO etc) standards and specifications as required.

4.6 All contractors engaged in drilling and well operations shall be capable of demonstrating technical, operational, quality, HSSE and commercial integrity in respect of their organisation, logistics, planning, procurement, execution, and performance evaluation.

Section 5
Preparing for Operations

5.1 Offshore

5.1.1 A baseline seabed survey of each proposed drilling location shall be conducted indicating physical conditions of the seabed. The appropriate techniques should be applied in keeping with the Offshore Site Investigation Manual (BPA-D-005).

5.1.2 A wellhead bending stress analysis and riser analysis shall be performed for floating drilling operations in the following circumstances:

- Prior to drilling with a new rig or in a new area
- Prior to using a wellhead or riser configuration not previously used in an area
- When the expected environmental conditions dictate this as being prudent

The wellhead bending stress analysis shall take account of wellhead stick-up. Limits on allowable wellhead angle commensurate with equipment in use shall be set. The analysis shall not be limited to drilling operations only but shall consider potential future use of the well for development operations if such use is considered a possibility.

5.1.3 A riser stress analysis and conductor analysis shall be performed for bottom supported operations taking into account all local environmental factors under the following circumstances:

- Prior to drilling in a new area
- Prior to using a mud line suspension system/conductor/riser/BOP configuration not previously used in an area

The bending stress analysis shall not be limited to drilling operations only but shall consider potential future use of the well for development operations should such use be considered a possibility.

5.1.4 At least one communication link shall be operating between the well site and the operations office at all times.

5.1.5 An offshore installation shall have man overboard procedures and the means to effect such rescue during drilling and well operations.

5.1.6 All offshore installations shall have procedures in place for full evacuation in the event of an emergency and severe weather.

5.1.7 Any vessel working in the support mode shall have direct communication with helicopters and the drilling unit.

5.1.8 Appropriate meteorological and oceanographic data pertaining to the area of the proposed well shall be available and taken into consideration prior to spud in, and for the duration of the well operation. Current sea state and weather forecasts shall be available both at the well site and at the operations office whilst operations are in progress.

5.2 Onshore

5.2.1 A communication link shall be operating between the wellsite and the operations office at all times.

5.2.2 Access to the wellsite shall be restricted to authorised personnel only.

5.2.3 Accommodation camps shall be sited in conformance with Group ETPs that relate to occupied buildings.

5.2.4 Reliable water supplies shall be provided to address all foreseen operational and emergency requirements prior to spud.

5.2.5 Appropriate assessments of shallow hazards of the proposed drilling location shall be conducted eg to identify any buried cables or pipelines and to determine the suitability of the site for drilling.

5.2.6 Prior to spud of any land drilling operation, a detailed review of historical data from offset wells shall be performed to assess the potential for encountering shallow gas prior to setting the first pressure containment string on the planned well. In the absence of compelling data to substantiate shallow gas is not present, shallow gas shall be assumed present and a diverter system shall be used when drilling the hole section(s) between the structural casing and the setting depth of the first pressure containment string.

5.2.7 Fuel and base oil storage shall be at a safe distance from the wellbore.

5.2.8 All onshore installations shall have procedures in place for full evacuation in the event of an emergency, severe weather and natural disasters.

Also refer to:

Section 17 Marine Geohazards

Section 22 Rig Audit and Acceptance

Section 6
Operational Readiness

6.1 A pre-operational meeting with the rig contractor, service company personnel and relevant BP personnel shall be held at the wellsite or operations office prior to the commencement of drilling or well operations. This meeting shall focus on the HSSE and operational performance expectations, operational objectives, differences from previous operations, hazards and contingencies.

6.2 The designated company representative shall be satisfied that the rig, equipment and site are in a safe operating condition, and that personnel are trained and competent, prior to commencing drilling and well operations.

6.3 An emergency evacuation drill, and for offshore locations, a man overboard drill, shall be carried out prior to commencement and at periodic intervals during a drilling or well operations campaign.

6.4 On floating drilling units, there shall be a demonstrable standard for stability and ballast control. Stability and ballast control drills shall be conducted.

6.5 The rotary table elevation, relative to seabed and water depth at mean sea level for offshore drilling units, or the rotary table elevation relative to ground level for land drilling rigs, shall be determined and formally recorded and communicated.

6.6 On moored floating drilling units, the mooring system shall be pre-tensioned to a value, and for a time as agreed with the rig contractor.

6.7 When carrying out floating drilling and well operations from a dynamically-positioned unit:

- Well-specific operating guidelines and emergency disconnect contingency plans shall be in place prior to running the BOP stack
- Drive-off drills shall be held at intervals agreed by the rig contractor. Drills are to be documented

6.8 Where the risks of scouring cannot be discounted, facilities for subsea visual or manual inspection shall be available. The frequency of these inspections shall be mutually agreed with the rig contractor.

6.9 Completion of the above requirements shall be formally documented in the relevant rig or operational logs.

Section 7
Wellsite Equipment

7.1 All drilling and well intervention units shall be fitted with sufficient instrumentation to continuously monitor and record all data appropriate for conducting the operation in a safe and efficient manner.

7.2 For all drilling and well intervention units a Crown-o-Matic or equivalent safety brake shall be installed on the drawworks and be operational at all times, and shall be subject to regular testing. Procedures shall be in place to manage routine and non-routine collision risks and shall take account of block inertia and headroom.

7.3 All drillpipes shall have either:

- No hard banding
- Hardfacing of casing-friendly wear resistant alloy overlays to a standard, finish and type approved by EPT

7.4 Drillpipe and bottomhole assembly components shall be inspected and graded in accordance with requirements laid down by the SPU. These inspections should be commensurate with operating conditions. API RP7G is the industry standard for drillstring design, operating limits and classification. Use of proprietary guidelines for inspection such as DS1 may be appropriate provided that results remain in compliance with API RP7G.

7.5 Dedicated and correctly rated equipment shall be used for riser handling on all floating drilling units and shall be inspected to an appropriate level prior to each job.

7.6 As a minimum, hazardous area designation shall reflect API RP 500B, or applicable regulations or SPU requirements, whichever is the more stringent.

7.7 All equipment shall be classed and certified as suitable for any hazardous areas in which it may be operated.

7.8 All pressure vessels and positive displacement pumps shall be fitted with an independent pressure relief mechanism or alternate safety mechanism. Relief lines shall be designed for the potential pressures and flowrates and have an adequate restraining mechanism. Consideration should be given to appropriate discharge location of venting systems.

7.9 When conducting offshore drilling and well operations an emergency powered or diesel black start firefighting pump capable of supporting two fire hoses or one foam branch shall be available.

7.10 A system shall be in place to ensure that all drilling and well operations equipment that requires certification has the correct certification and that it is valid.

7.11 All items of BP owned, contractor owned and third party owned lifting and load bearing, pressure containing and safety critical equipment shall be covered by a maintenance management system that allows safe operation and technical integrity for the intended operating envelope.

7.12 Only replacement parts that meet or exceed the original equipment manufacturer's design, specifications and manufacture shall be used in safety critical equipment (except for well control equipment, refer to Section 15).

7.13 All high-pressure pipework assemblies equipped with hammerlock unions shall be manufactured to a recognised specification and be subjected to a routine inspection, testing and maintenance programme. Controls shall be in place to ensure direct interconnection of incompatible types and manufactures is avoided.

Section 8
Drilling and Completions Practices

8.1 Formation leak-off or integrity tests shall be performed after drilling out each casing or liner shoe prior to drilling the new hole section, except for conductors. Corrective measures shall be performed if the open hole pressure integrity fails to meet predetermined standards.

This requirement for formation leak-off or integrity test may be relaxed after a documented risk assessment, conditional upon indications of a good cement job, under the following conditions:

- Casing string is not a pressure containment string
- Exposed formations are very vulnerable to damage and such damage will subsequently increase the level of risk
- Casing shoe is set by design within the target reservoir
- Where air or underbalanced fluids are the primary circulating medium

8.2 At all stages during the drilling of a well it shall be assured that assumptions made during the casing design are not violated.

8.3 Choke line pressure losses shall be determined and recorded on floating drilling units:

- Prior to drilling out casing
- On any significant change in mud weight

8.4 A full dimensional check of all drilling, testing or completion tools shall be carried out and the results recorded prior to running tools in the hole. The record shall be available at the drilling site.

8.5 When coring, the inner barrel will have provision for venting trapped pressure at regular intervals.

8.6 A coring task risk assessment shall be conducted to identify hazards and mitigating procedures to cover handling procedures, H2S potential, wellbore fluids and cutting tools as a minimum.

8.7 Selection of appropriate wellbore fluids and operating practices should address the potential for hydrate formation and mitigation.

8.8 The drilling site shall be left in a condition which conforms to a standard formally recognised by the appropriate Performance Unit in conformance with the expectations of the Local Operating Management System.

8.9 Prior to leaving an offshore location, a seabed survey shall be peformed and any debris that cannot be reasonably recovered shall be documented.

8.10 Safe handling zones shall be established to avoid damage to subsea infrastructure from dropped objects.

8.11 Any offshore operations subject to loop currents shall have an established contingency plan to manage risks.

Section 9
Drilling Fluids

9.1 Drilling fluids generally provide the primary well control barrier and every well drilled shall have a drilling fluids programme. The programme shall, as a minimum, provide information on mud types, and property ranges for mud weight, rheology and filtration control. Contingency plans as a minimum should be included for minor and serious lost circulation, differentially stuck pipe, wellbore instability and well control.

9.2 Basic API testing of the active drilling fluids system shall be conducted and reported at least once daily during drilling operations.

9.3 A minimum quantity of weighting material shall be readily available onsite during all phases of the well, to weigh up the circulating volume by 1 pound per gallon. Individual programmes should define acceptable stock levels based on the nature of the operation and the supply logistics.

Also refer to:

Section 15 Well Control

Section 18 Waste & Fluids Pollution Risk Mitigation

Section 10
Cementing

10.1 Every well shall have a cementing programme in which the following have been considered:

- Structural integrity including long term corrosion
- Zonal isolation (Ref GP 10-60)
- Future abandonment

10.2 Prior to each cementing operation, representative samples of cement, additives and mixing water to be used shall be taken and tested according to ISO requirements (or BP specified testing regime).

10.3 In locations where supplies are intermittent, a minimum supply of cement and cement and additives shall be kept on the drilling site. The volumes shall be at least enough to set appropriate isolation plugs in the current hole size.

10.4 All cementing equipment shall be maintained according to suppliers maintenance schedules and pressure retaining equipment shall have appropriate certification.

10.5 The predicted pressures (surface and downhole) during cementing should be reviewed, assessing any risk of overpressuring surface equipment, initiating losses or under balancing the well.

10.6 High pressure cementing equipment shall only be operated by trained personnel.

10.7 Density of all fluids pumped during the cement job should be confirmed during cementing operations

Section 11
Reporting and Data Management

11.1 Reporting

11.1.1 The following reports shall be a minimum for all drilling and well operations and shall be retained within the SPU:

- IADC Drilling Report Form or equivalent where a rig is used
- BP daily report. For drilling, completions and well intervention activities DIMS/OpenWells is the required format
- Casing and cementing reports
- Well data acquisition records
- Seabed clearance certificate at start and end of well operations
- Abandonment, suspension and completion diagrams
- Accident and incident reports
- Well control incident reports
- Safe operating limits for each well
- A current persons onboard list shall be maintained at, or immediately accessible to, the emergency control centre
- Government permits and forms
- Definitive final well surface location and directional survey report

11.1.2 A complete set of well files recording the history of all drilling, completion and well operations from spud to final abandonment shall be retained within the SPU. Details of any fish left in hole shall be specifically included in such files.

Well file data should be secure and accessible for the duration of BPs liability for the well.

11.1.3 The document management system shall provide an auditable trail of:

- Updates and modifications
- Deviations from ETPs, STPs or SOPs
- Approvals and review by EAs

11.2 Data Management

11.2.1 SPUs shall maintain a written life-of-field management plan for all safety critical data. Security and back-up processes shall be tested prior to implementation. Safety critical data shall only be created, edited or deleted in accordance with the management plan. The production and interpretation of all safety critical results shall be subject to an assurance process with an audit trail.

11.2.2 For tubular design, safety critical data shall include, but is not limited to:

1. Well location, depth datum, total depth, water depth and objective depths(s);
2. Definitive wellbore survey;
3. Designation as exploration or development well;
4. Hydrocarbon composition;
5. List of tubulars (outside diameter, wall thickness, grade, connection), annular fluids, tops of cement and hanger depths for all casing and tubing installed in the wellbore;
6. Design loads and safety factors;
7. Casing wear;
8. List of any significant accessories to the tubular string(s) and their locations;
9. Details of any APB mitigation installed in each annulus;
10. Service life data including drilling, completions, testing, production, workover, sidetracking, etc.

Section 12
Safety Critical Software

12.1 The definition of Safety Critical Software is a computer application that undertakes automated control, calculation and/or modelling of outcomes that provide equipment control, engineering design and/or operational guidance for safety critical tasks.

Safety critical tasks in D&C involve the following:

- BP Tasks:
  - Casing and Tubing design
  - Well Positioning
  - Pore Pressure Detection and Measurement
  - Well Control
- Contractor Tasks:
  - Automated Pipe Handling systems
  - Ballast Control
  - Deepwater (electro/hydraulic) BOP Control
  - Dynamic Positioning Control
  - Rig Positioning

The definitive list of BP applications can be found from the Drilling and Completions Portfolio Manager.

12.2 Software, verified via a documented process, as assured by the appropriate BP SETA shall be used for safety critical tasks as defined in the ETPs. For BP tasks such software shall be maintained, controlled and released by the IT&S Drilling and Completions Service Desk to ensure effective management of updates, new releases and design.

12.3 SPUs shall only use the approved versions of Safety Critical software as distributed by the IT&S Drilling and Completions Service Desk in accordance with the requirements of the SETAs. All Safety critical software shall either:

- be accessed and used on the CITRIX central server farm where this exists for the SPU
- or, where no such farm exists, safety critical software shall be downloaded onto users' computers via the Altiris system. Users shall accept and use downloads of new versions of software when they are notified by Altiris that it is available. SPUs shall be able to demonstrate that the appropriate versions have been installed

Any deviation to these 2 methods of deployment shall be approved in advance by the appropriate SETA.

During upgrades, there may for a period, be more than one approved version of the software.

12.4 New or alternate software to perform safety critical tasks can only be used when approved in advance by the appropriate SETA.

12.5 SPUs are accountable for Data management for safety critical software and systems. SPUs shall ensure the accuracy and integrity of their data and that effective back up systems are in place.

12.6 SPUs shall ensure that contracts address safety critical software for Contractor tasks to ensure that appropriate standards are maintained for installation, operation and disaster recovery.

Part 'B'

Significant Risk Practices with ETPs

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-01

Section 13
Casing & Tubing Design

All Casing and Tubing design activity shall conform to Engineering Technical Practice GP10-01 – Casing & Tubing Design.

13.1 Design

13.1.1 All casing and tubing designs shall be addressed in a well basis of design document. If that document is field-wide, a separate document shall, when appropriate, stipulate where a specific well design deviates from the field-wide basis of design.

13.1.2 A casing and tubing design shall be performed for all wells and should incorporate foreseeable life-of-well requirements and abandonment. Where wells are to be produced, tested, stimulated, injected or modified, a design check shall be performed for the existing configuration, unless as part of the SPU assurance process a previous design is demonstrated to be adequate.

Design Standard

13.1.3 The requirements contained within the BP Tubular Design Manual (BPA-D-003) shall be applied for both the tubing and casing program basis of design. The basis of design will address parameters within which it is acceptable to plan further wells in a programme, campaign or area without further detailed design. When these parameters are exceeded, a detailed reassessment of the design is required.

Tools and Design Data

13.1.4 Casing and tubing design shall be performed using the BP approved casing design software and methods as identified in the BP Tubular Design Manual. Exceptions shall be subject to EPT review.

13.1.5 Every tubular component in the load path or forming part of the pressure envelope shall be traceable per API, ISO, and/or BP specifications and verified either by reference to the mill certificates or mechanical testing to have the expected mechanical performance. Every component shall also be in good condition, and all equipment should be suitable for expected service life.

13.1.6 Casing and tubing design software are safety critical.

13.1.7 Casing and tubing designs shall be subject to assurance review as a minimum shown in Table 1.

Table 1 – Required Well Design Review Level

Well Category	Minimum Review Level
1. All wells	Within SPU
2. Wells with SITHP > 10,000 psi or SBHT > 300°F, or reservoir pressure > 15,000 psi, or H_2S partial pressure > 0.05 psia, or water depth > 1000 ft (300 m) or using reduced drilling service or well control loads outside of the guidance of this ETP or the BP Tubular Design Manual	SPU plus review by a party external to the SPU
3. Wells requiring material with specified yield strength > 125 ksi, or requiring sour service materials with specified yield strength ≥ 110 ksi, or having sealed or potentially sealed inaccessible annuli or requiring modelling outside standard software capabilities, or using reduced production loads outside of the guidance of this ETP or the BP Tubular Design Manual	SPU plus EPT review

Notes:

1. A party external to the SPU is a person of technical competence whose current performance contract is not directly dependent on the success of the SPU, and may include individuals from other SPUs, individuals from EPT or external consultants.
2. The final qualifier in Table 1 specifically targets complex completion designs (*e.g.* downhole flow control, multiple packers) that do not lend themselves to ready analysis in available tubular design software, but require either special handling with conventional tools or the use of modelling tools outside the purview of a non-specialist.

13.1.8 A minimum set of design loads, including setting depth, burst, collapse, tension and triaxial considerations for both the tube body and connection, is defined in the BP Tubular Design Manual. Designs governed by loads outside those listed in the BP Tubular Design Manual shall be subject to review as in Well Category 3 in Table 1.

1. All casing and liners shall be designed to withstand reasonably foreseeable well control burst loadings. The starting point for well control burst loading shall be gas to surface from casing shoe, or lower open hole fracture pressure. Casing designs using lesser well control loadings not appearing in the BP Tubular Design Manual as acceptable alternatives shall be subject to review as per Well Category 2 in Table 1.
2. Casing designs shall include definition of the well control scenarios they accommodate and their rationale based on subsurface information, local experience and operational well control capabilities. Kick intensities for well design shall be based on appropriate and prudent application of pore pressure uncertainty as described in GP 10-15 Group Practice on Pore Pressure Prediction.
3. All production casing and liners shall be designed for burst, to withstand the maximum pressure resulting from a tubing leak at the wellhead applied over the packer fluid.

Design Factors

13.1.9 The minimum acceptable design factors for BP tubular design calculations are given in Table 2.

Table 2 – Minimum Casing and Tubing Design Factors

	Casing		Tubing (Test)		Tubing (Service)	
	Pipe	**Connection**	**Pipe**	**Connection**	**Pipe**	**Connection**
Tension	1.4	1.4	1.1	1.1	1.33	1.33
Burst	1.1	1.1	1.1	1.1	1.25	1.25
Collapse	1.0	1.0	1.1	1.1	1.1	1.1
Triaxial	1.25	N/A	1.1	N/A	1.25	N/A
Compression	1.4	1.0	1.1	1.0	1.33	1.0

13.2 Procurement

Standard

13.2.1 Casing and tubing shall be manufactured, inspected and tested in accordance with the standards as outlined in the ETP 10-01.

Qualifying Materials

Sour and/or Corrosive Service

13.2.2 The materials selection process for wells expected to contain H2S shall comply with NACE MR0175/ISO 15156. Only seamless grades of tubulars are acceptable for casing and tubing which may be exposed to H2S/sour environments as defined in NACE MR0175/ISO 15156.

13.2.3 The materials selection process for production tubulars expected to contain CO2 and/or H2S shall follow the requirements of BP EPT Guidance Note GN 036-13. In case of a conflict between this document and NACE MR0175/ISO 15156, the more onerous requirement shall govern.

Alteration of Specification Properties

13.2.4 Field welding of tubulars is permitted on API Spec 5L/ISO 3183 grade line pipe and API Spec 5CT/ISO 11960 Grade K55 tubulars, and shall conform to the guidelines laid out in API RP 5C1/ISO 10405. Welding operations on other grades of pipe will require specific qualifications and procedures per GP 18-01.

Well-site Inspection

13.2.5 All casing, tubing and handling tubulars shall be visually inspected and drift tested as close to the point of use as practical to identify handling damage to the pipe body and threaded connections that could present problems during installation and/or over the life of the well.

13.3 Operation

Loads

13.3.1 Operations during installation and well life shall not exceed the loads under which exposed tubulars have been designed. A revised design evaluation shall be completed, should such an occurrence be contemplated.

Setting Depths

13.3.2 Casing and liner setting depths shall be selected to provide a sufficient safety margin between formation fracture pressure and well control and/or casing cementing operations. Limitations on allowable well control operations shall be detailed in the design.

Also refer to:

Section 12 Safety Critical Software

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-05

Section 14
Directional Drilling & Surveying

All directional Drilling & Surveying activity shall conform to Engineering Technical Practice GP10-05 – Directional Drilling & Survey.

Scope of Application

14.1 ETP GP10-05 applies specifically to subsurface well collision risk. It will be applied to all operations where this risk presents a threat to personnel safety or the environment. This will be determined by means of a risk assessment.

Data Structures, Integrity & Management

14.2 A Master Database of all well trajectories shall be maintained and be the subject of a written data management plan covering the full life of the field. The co-ordinate reference system used by the Master Database shall be determined by a Company Surveyor. This database shall be classified as safety critical and managed accordingly.

Surface Location Management: New, Single Well Locations

14.3 The final position shall be determined as the well is spudded. The Electronic Well Location Management (eWLM) process shall be used to manage the planned and final location of the well. The drilling unit shall be positioned and the final location confirmed using approved positioning contractor procedures and supervised by an independent survey representative.

Surface Location Management: Built Facilities (platform, sub-sea template, land site)

14.4 The surface position shall be managed in accordance with the plans, procedures and documentation controlled by the respective project authority.

Survey Programme Design

14.5 Survey programmes shall be designed to meet clearly defined quantitative positioning objectives such as:

- Meet local government regulations
- Penetrate the geological target(s) set in the well's objectives
- Minimise the risk of intersection with any nearby wellbore
- Drill a relief well
- Avoid location of shallow hazards

Uncertainties shall be calculated using approved survey tool error models and calculation methods. The well survey programme shall take surface location uncertainty into account and shall contain sufficient redundant data to eliminate the possibility of undetected gross errors.

Anti-collision Scan

14.6 Anti-collision scans for all wells shall be run against the Master Database. The minimum separation distances shall be calculated using the equations in ETP 10-05. SPU staff and contractors involved in the activity shall be trained and competent in the methods employed.

Operational Control and Assurance

14.7 Directional drilling and surveying operations shall be conducted by contractors in compliance with their approved procedures. Survey programmes shall be executed in accordance with their designs or any approved changes thereto. Where operational problems occur, any modifications to the programme shall be shown to fulfil the same requirements as the original design, or a Management of Change process undertaken to revise the original requirements. SPU staff shall be responsible for implementing and monitoring compliance.

All procedures, directional software and the software settings employed by contractors, wellbore survey tools and their running procedures Joint Operating & Reporting Procedures (JORPs) shall be assessed by the EPT Well Positioning Specialist and approved by the Segment Engineering Technical Authority for Directional Drilling and Surveying.

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-10

Section 15
Well Control

All Well Control activity shall conform to Engineering Technical Practice GP 10-10 – Well Control.

15.1 Well Control Training & Preparation

General Requirements

Each BU shall designate a well control TA responsible for fulfilment of expectations set out in this ETP. Said TA is not required to reside within the respective BU and may be designated outward. Additionally, individual well control SPAs' may be designated within each PU as required by the BU. Each SPA shall notify the designated BU TA of any well control issues. Additionally, each BU TA shall notify and address all significant well control issues with the Segment TA.

Training & Certification

All BP drilling and well operations personnel, and personnel acting on behalf of BP, who are directly involved in planning and execution of BP drilling and well operations, plus any contractor personnel who may take control of well activities (such as toolpushers, drillers, assistant drillers, subsea engineers and service unit operators) shall have a valid and recognized well control certificate.

15.1.1 Valid and recognized well control certification authorities include IWCF, IADC, AEUB and others that may be designated by the Segment well control TA upon request by the BU.

15.1.2 Well control certifications shall be renewed at periods not exceeding twenty-four (24) months.

15.1.3 BUs shall be adequately prepared to remediate any well control event through the use of a Well Control Response Guide and the BP Well Control Manual. Framework of each well control response guide shall required endorsement of the Segment well control TA.

15.1.4 All BP personnel and personnel acting on behalf of BP, who are directly involved in the planning and execution of BP drilling and well operations, shall be trained and competent in participation of a Well Control Response Guide.

Well Control Preparation

15.1.5 All drilling operations involving static fluid level designs; bore protectors or wear bushings shall be installed in the wellhead during all drilling operations. The wellhead design shall take this into account. If operations preclude the use of bore protectors or wear bushings this policy may be relaxed after completion of a documented risk assessment and BU well control TA or designate approval.

15.1.6 For conventional drilling operations, the kick tolerance of the weakest known point of the hole section being drilled shall be updated continuously while drilling and reported on all BP daily drilling reports. This requirement for kick tolerance calculation applies to drilling of all hole sections after the first pressure containment string has been set.

15.1.7 Kick tolerance is defined as the maximum volume of kick influx that can be circulated out of the well without breaking down the formation at the open hole weak point. Kick tolerances are to be calculated as described in the Well Control Manual.

15.1.8 On all wells the design kick tolerance shall be greater than 25 bbl based on maximum anticipated pore pressure and planned mud weights. This policy may be relaxed only after a documented risk assessment, approved by the BU well control TA or designate and conditional under the following conditions:

- Confirmation of a good cement job
- Open hole formations in infield drilling areas are known to be normally or sub-normally pressures based on established history
- Losses are expected in the target areas
- Where air or under balanced fluids are the primary circulating medium
- Before any unshearable component enters the BOP stack

15.1.9 The calculation updating requirement and the 25 bbl volume requirement may be relaxed after a documented risk assessment, and approval of the BU well control TA or designate and conditional upon indications of a good cement job, under any of the following conditions:

- Open hole formations in infield drilling areas are known to be normally or sub-normally pressured based on established history
- Losses are expected in the target based on established history in infield drilling areas
- Where air or under-balanced fluids are the primary circulating medium

15.1.10 All drilling breaks shall be flow-checked and reported to the BP designated company representative, based on criteria established between the BP designated company representative and the driller or service unit operator.

15.1.11 Balanced drilling and conventional and hydraulic workover operations, involving static fluid column designs, as a minimum, shall be perform flow checks while tripping out of hole:

- Before pulling off bottom
- After pulling into the casing shoe
- Before the BHA enters the BOP stack

15.1.12 Balanced drilling, conventional and hydraulic workover operations, involving static fluid level designs, trip sheets shall be filled out by the driller / operator on every trip in and out of the hole. Any deviation from expected hole fill up volumes shall be investigated based on criteria provided by the BP designated company representative.

15.1.13 Slow circulating rates shall be taken every tour, each time a BHA change is made, when significant mud properties change and 500 feet of new hole is drilled. Choke line frictions will also be considered.

15.2 Well Control Practices

General Requirements

15.2.1 Tested BOPE shall be installed for drilling operations below the surface casing shoe.

15.2.2 The BOP stack and wellhead in place at any point during the course of the well, shall be of sufficient working pressure and temperature rating to contain the maximum allowable surface pressure and temperature from total depth of the current open hole section.

15.2.3 The maximum allowable wellhead pressure shall take into account a gas column to surface for exploration and appraisal wells, whilst for development wells reservoir fluid shall be used.

15.2.4 In balanced drilling, conventional and hydraulic workover operations involving static fluid column designs, the designated company representative shall be present prior to each trip to flow and loss check the well and then directly observe the trip until satisfied the wellbore fluid level is stable and the hole fill volume is correct.

15.2.5 In unconventional operations without static fluid levels, the designated company representative shall observe the pre-trip well conditions and assure themselves that the well will behave in accordance with expected norms for the planned operations.

15.2.6 After completing all well kills or well testing operations, the designated company representative shall be present to flow and loss check the well and directly observe the trip until such time as they are satisfied that the wellbore fluid level is stable and/or the hole is safe to trip prior to pulling out of the hole.

15.2.7 Kick detection, diverter, circulating, stripping, and shut-in drills shall be held regularly until the designated company representative is satisfied that each crew demonstrates suitable BP standards.

15.2.8 Thereafter kick detection and shut-in drills shall be performed at a minimum of once per week per crew and be reported in the Daily Report form.

15.2.9 A shut-in method shall be established, communicated and practiced which minimizes influx and impact to the wellbore. Line and valve configurations shall be planned, communicated and regularly checked by the driller or service unit operator and position confirmed with the BP well site leader or his designate.

15.2.10 The driller / operator is responsible for and authorized to shut the well in. The designated company representative shall be the only person authorized to initiate opening the well as part or conclusion of well control measures.

15.2.11 Except during under balanced drilling, a drilling well kick sheet shall be maintained and updated for immediate use in the event of a well control event.

15.2.12 A well control incident report shall be completed and documented within the Tr@ction reporting system following any well control incident.

15.2.13 At least one contingent barrier i.e. down hole float valve shall be included on any casing string run through a hydrocarbon-bearing formation.

15.2.14 Differential fill float equipment shall not be used on casing strings which are to be run through potential hydrocarbon-bearing zones. This policy may be relaxed after a documented risk assessment and approval of the BU well control TA or designate.

15.2.15 Auto fill float equipment shall be tripped prior to running through any hydrocarbon bearing zone.

15.2.16 For all exploration, HPHT and H2S appraisal wells a well specific Well Control Response Guide shall be prepared.

15.2.17 A well control interface / bridging document shall be prepared with the appropriate contractor to ensure there is clear understanding of responsibilities and which reference documents and procedures will be used in a well control situation.

15.2.18 Each BU shall ensure that well control response guides are maintained in every supporting OC and base office and emergency drills regularly conducted and reported. These guides shall address the availability of a means of quickly evacuating the well site and responding to an event.

15.2.19 During well construction and maintenance activities, operations shall be conducted with one active barrier and one contingent barrier installed to address critical operational risks and contain the well.

15.2.20 During conventional drilling, completions and well work activities the active barrier shall normally be a stable fluid column and the contingent barrier shall be the blowout preventer (BOP) equipment or tree. During under-balanced drilling, wireline, snubbing and coil tubing intervention activities, the active barrier shall normally be a dynamic mechanical sealing device and the contingent barrier shall be the BOP or tree.

15.3 Conventional Well Control Equipment

General Requirements

The requirements of this section shall apply to all well control equipment used in drilling and well operations. They represent the general requirements to mitigate Major Accident Risk (MAR) potential. These requirements shall be exceeded for higher risk activities which may result, for example, from a combination of factors such as under-balanced drilling, coil tubing drilling, H2S, etc. Conversely and except in offshore operations, the requirements may warrant relaxation in lower risk activities or areas where the MAR is demonstrated to be below Group reporting limits and/or compliance with these requirements increases personal exposure to risk. Still other, special risk activities employed in several BP operating areas are not detailed in these requirements including air drilling, stripping, temporary stimulation tree/surface configurations.

In either the high, low or special risk cases mentioned above, the operating unit shall develop the relevant procedures based on risk assessment, the general context of these requirements and with reference to appropriate industry guidance and the BP Well Control Manual.

15.3.1 Systematic documented risk assessments and procedures shall be required to confirm the suitability of all contingent barriers other than BOP's and trees. Such contingent barriers include but are not limited to cement plugs, packers and storm valves.

15.3.2 For all exploration and appraisal drilling operations, an independent recordable means of monitoring wellbore conditions shall be used.

15.3.3 When conducting all offshore drilling and well operations, emergency power arrangements shall be set up to enable operation of the cementing unit, the BOP control panel and ancillary services for well control contingency purposes.

15.3.4 All hammer-lock unions shall be positively identified as to manufacturer, service and pressure rating prior to assembly and use. Additionally equipment shall be able to demonstrate actual Preventative Maintenance (PM) performed. Controls shall be in place to ensure direct interconnection of different types, pressure ratings and manufactures is avoided.

15.3.5 The BOP, choke manifolds and associated equipment (i.e., equipment that is flow wetted and pressure containing) shall always be designed for an H2S environment in areas where the probability of any H2S exists, i.e., 'H2S trim'. In areas where the presence of H2S can not be determined H2S equipment shall be employed.

Equipment Modifications, Changes & Repairs

15.3.6 All modifications, design changes or weld repairs to well control equipment shall comply with appropriate API specifications, manufactures specifications or government regulations, whichever is more stringent.

15.3.7 Only original equipment manufacturers' designated spares shall be used for blowout preventer equipment (BOPE) replacement parts. Where older, out-of-service equipment models dominate the industry in an operating area, after-market replacement parts that meet the original manufactures specifications are acceptable provided a documented risk assessment is completed and approved by the BU well control TA.

15.3.8 Ring joint gaskets with metal-to-metal sealing are preferred, but suitably qualified alternatives with elastomer backup are permissible where a documented risk assessment reveals no life-of-well integrity issues and approved by the BU well control TA or designate.

Configuration: Drilling Diverter Equipment

15.3.9 Diverter equipment shall be installed and operational to manage shallow hazard potential as specified in GP 10-20 (Shallow Hazards). Diverter systems shall only be considered as a means of controlling unexpected shallow hazards which have not been identified from site specific surveys. All offshore well locations shall have a shallow hazard assessment. Where this survey identifies possible shallow hazards, the location shall be moved to avoid the anomaly.

15.3.10 Where a riser and diverter system is to be used, the equipment shall be evaluated and the diverter system shown to be adequate for the likely diversion scenario utilizing the possible pressure and fluid regime anticipated.

15.3.11 The pressure rating and sizing of all diverter system pipe work and valves shall be shown to exceed anticipated pressures for a likely diversion scenario and to minimize the risk of broaching from the casing shoe.

15.3.12 Where a riser and diverter system is to be used, the formation strength at the casing shoe shall be sufficient to avoid an underground flow.

15.3.13 The diverter control system shall be sequenced to ensure that a side outlet is open and the shale shaker valve is closed prior to the diverter element closing.

15.3.14 On closing the diverter element, flow shall be confined to the designated diverter lines only.

15.3.15 In cases where rupture discs are used, the diverter line valve, if installed, shall remain locked and tagged open.

15.3.16 The diverter control system shall operate all necessary valves and close the diverter element within 30 seconds for systems with a nominal bore of 20 inches or less. For systems with greater than 20 inch bore, the operating time shall not exceed 45 seconds.

15.3.17 The diverter control panel shall be located adjacent to the driller's / operator's position, with a second control panel located in a designated safe area.

15.3.18 Diverter lines shall be designed or audited to API RP-64. Diverter lines on offshore units shall have a minimum internal diameter of 12 inches. Diverter lines for onshore drilling operations shall have a minimum internal diameter of 8 inches. All diverter line valves and lines shall be full opening and designed as straight as possible. Where rig designs require, targeted turns will be allowed after a documented risk assessment is performed and approved by the BU well control TA or designate.

15.3.19 Upon installation and prior to drilling hole sections where diverting is the planned means of well control the diverter system shall be function tested and, subject to local environmental constraints, the diverter lines flushed. Thereafter, the diverter system shall be function tested at least once every seven (7) days. Diverter lines with rupture discs shall be inspected only and results recorded.

15.3.20 Offshore rigs shall have dual diverter line systems.

15.3.21 Any diverter vent line shall terminate in a safe location.

Configuration: Surface Drilling, Completion, Conventional and Hydraulic Workover BOP Stacks

15.3.22 As arranged from top to bottom, the minimum BOP configuration shall be required for wells where a wellhead pressure up to and including 3,500 psi is possible, is:

- One annular preventer
- Two ram type preventers, the upper most shall be blind or blind shear
- Outlets for choke and kill lines shall be positioned above the lower most set of pipe rams

15.3.23 As arranged from top to bottom, the minimum BOP configuration shall be required for wells where a wellhead pressure of over 3,500 psi is possible, is:

- One annular preventer
- Two ram type preventers, the lower of which shall be blind or blind shear
- Outlets for choke and kill lines
- One pipe ram

15.3.24 Stripper heads are an acceptable alternative to the annular preventer for onshore well work applications provided a documented risk assessment is completed and approved by the BU well control TA or designate. If used offshore for under balanced workovers, a stripper head shall be supplemental to an annular preventer.

15.3.25 For offshore operations sealing shear rams shall be installed.

15.3.26 All surface BOP stacks shall incorporate at least one choke line and one kill line which enter the stack above the lowermost set of pipe rams.

15.3.27 Kill and choke lines installed below the lowermost set of rams or wellhead other outlets shall be used for pressure testing or monitoring the well only.

15.3.28 The BOP stack shall contain a pipe ram that can close on every size of drill pipe, casing and tubing that comprises a significant length of the total string. Where tubular accessories (e.g. cables, clamps, screens etc) may compromise a shear ram or pipe ram seal, then appropriate procedures and contingencies shall be in place to mitigate this risk.

15.3.29 Where multiple similar rams are fitted, the lowermost ram shall be preserved as a master component and shall only be used to close in the well when no other ram is available for this purpose or for the purpose of upper BOP repairs or re-configuration.

15.3.30 Dual, full-opening valves shall be provided on each choke and kill line for all stacks. The outer valve on the choke line shall be remotely activated. The outer valve on the kill line shall either be a remotely operated or a non-return valve shall be fitted.

15.3.31 Each ram type preventer shall have a functional ram locking device fitted.

15.3.32 The standpipe manifold and cement manifold shall have double valve isolation from the kill line.

15.3.33 Accumulator test shall be carried out in accordance with the requirements set out in the well control manual.

Configuration: Subsea Drilling, Completion & Workover BOP Stacks

15.3.34 As arranged from top to bottom, the minimum BOP configuration shall be required for wells where a wellhead pressure up to and including 5,000 psi is possible, is:

- One annular preventer that is retrievable on the lower marine riser package
- Three ram type preventers
- Outlets for choke and kill lines

There shall be a minimum of one kill line and one choke line connected to the BOP stack.

15.3.35 As arranged from top to bottom, the minimum BOP configuration shall be required for wells where a wellhead pressure of over 5,000 psi is possible, is:

- Two annular preventers, one of which is retrievable on lower marine riser package
- Four ram type preventers
- Outlets for choke and kill lines

There shall be a minimum of three inlets/outlets. Where there are four inlets/outlets, one shall be below the lowermost ram. Where there are three inlets/outlets, the single kill or choke line connection shall not be below the lowermost ram.

15.3.36 A sealing shear ram shall be required. The limitations of its shearing capacity should be known and understood, and a documented risk assessment shall be in place to address any such limitations.

15.3.37 Except in emergencies following the failure of the primary kill and choke lines, any outlets and lines installed below the lower most set of rams shall be used for pressure testing and monitoring the well only.

15.3.38 The BOP stack shall contain a pipe ram that can close on every size of drill pipe and tubing that comprises a significant length of the total string. Where tubular accessories (e.g., cables, clamps, screens, etc) may compromise a shear ram or pipe ram seal, then appropriate procedures and contingencies shall be in place to mitigate this risk.

15.3.39 The lowermost ram shall be preserved as a master component and only used to close in the well when no other ram is available for this purpose.

15.3.40 Ram type preventers shall have remotely or automatically operated ram lock systems fitted.

15.3.41 Both the standpipe manifold and cement manifold shall have double valve isolation from the kill line.

15.3.42 Opening and closing volumes of all BOPE functions shall be monitored and recorded on subsea stacks.

15.3.43 Accumulator test shall be carried out in accordance with the requirements set out in the well control manual.

Configuration: Rod Pump Pressure Control Equipment

15.3.44 This section applies to well servicing of wells with sucker rods, co-rod, drive shaft deliquification or similar through-tubing lifting systems where uncontrolled flow of well fluids cannot be sustained.

15.3.45 Prior to pulling rods, a manual single BOP shall be installed atop the flow tee.

15.3.46 A pump in connection point shall be available below the rod BOP.

Other Well Control Equipment

15.3.47 A full-open safety valve rated to the same pressure as the BOPs shall be available and ready to install on the rig floor at all times. Crossovers shall be available such that the full-open safety valve can be attached to any string of pipe to be run in the well. Contingencies for installing a safety valve and circulating casing at any time shall also be available.

15.3.48 On surface wellheads during the drilling and well operations, a minimum of one casing spool side outlet to the casing string being drilled through or worked in shall be equipped with double full-opening valves, companion flange and needle valve to allow installation of a pressure gauge. The principle of two full-opening valves is based upon using one as a master valve and one as a working valve when conducting pumping and circulating through the outlet.

15.3.49 The other side outlet(s) to this wellhead shall have either a valve removal (VR) plug or a full-opening valve and shall be equipped with a companion flange and needle valve installed to enable the installation of additional valves, if necessary.

15.3.50 Existing installed equipment which cannot meet the above design requirements based on lack of VR profile or based on outlet design shall have two outlet valves. The full opening requirement may be relaxed after risk assessment. New wellheads shall comply with the full-opening requirement.

15.3.51 On surface wellheads during the drilling and well operations, a minimum of one casing spool side outlet to any casing annulus shall be equipped with a single full-opening valve, companion flange and needle valve to allow installation of a pressure gauge. This single valve shall not be used to pump or flow through.

15.3.52 The opposing side outlet(s) to this wellhead shall have either a VR plug or a full-opening valve and should be equipped with a companion flange and needle valve installed to enable the installation of additional valves, if necessary.

15.3.53 Existing installed equipment which cannot meet the above design requirements based on lack of VR profile or based on outlet design shall have a single outlet valve companion flange and needle valve to allow installation of a pressure gauge. The full opening requirement may be relaxed after a documented risk assessment and approval of the BU well control TA or designate on existing well heads only. New wellheads shall comply with the full-opening requirement.

15.3.54 Prior to the use of VR plugs a full risk assessment shall be completed and a maintenance program established to monitor and evaluate VR plug conditions.

15.3.55 All drilling, offshore workover, service and offshore HWO units shall have a BOP control system with two independent and operational hydraulic charging systems.

15.3.56 BOP control systems for onshore workover or service rigs and where uncontrolled flow of well fluids or gasses cannot be sustained shall have an accumulator with at least one operational hydraulic charging system.

15.3.57 All drilling units, on and offshore, workover, service (excluding snubbing, CT and wireline equipment) and HWO units shall be at least two operational control panels for all BOP functions one of which shall be located adjacent to the driller's or operators position, with a second located in a designated safe area.

15.3.58 The primary hydraulic control unit, which may be considered as the second control panel, shall be located in a designated safe area or protected by effluent well conditions.

15.3.59 On well service units where the operator works at ground level, a second panel is not necessary, provided that the primary hydraulic control unit is located in a designated safe area and immediately accessible to the operator within four (4) seconds.

15.3.60 The working fluid volume of BOP accumulators and the BOP closing times shall comply with API RP 53 and the BP well control manual.

15.3.61 Choke manifolds are required on all drilling, conventional and hydraulic well work units and shall incorporate a minimum of two adjustable chokes, one of which shall be capable of remote operation.

15.3.62 Drilling unit choke lines, valves and the inlet side of manifolds shall be sized 3 inches minimum internal diameter for surface and subsea stacks.

15.3.63 On and offshore workover, service, HWO, Snubbing and Coiled Tubing unit choke lines, valves and the inlet side of manifolds shall be sized 2 inches minimum internal diameter for surface and subsea stacks.

15.3.64 Discharge lines and vessels from permanent and temporary choke manifolds Hshall be properly secured and inspected to prevent any movement during highest anticipated flow rates and pressures. These systems shall be assessed as being fit for purpose.

15.3.65 There shall be calibrated choke manifold and standpipe gauges in close proximity to the choke controls and visible to the operator at all times.

15.3.66 Gauges suitable for accurately reading low drill pipe and casing pressures shall be available along with a suitable manifold arrangement. Low pressure gauges shall not remain plumbed into the well control system during normal operations or employ a means of isolation from the system during high pressure operations.

15.3.67 A pressure gauge shall be mounted on the standpipe and choke manifolds. The gauge shall be of the same nominal pressure rating as the equipment on which it is installed.

15.3.68 Conventional drilling and offshore workover operations with static fluid levels in the wellbore as the active barrier, a means of accurately monitoring fill-up and displacement volumes shall be available to the driller / operator. A low volume trip tank shall be installed and equipped with a volume indicator easily read from the driller's / operator's position.

15.3.69 During the well planning phase, a risk assessment shall be made regarding the necessity of a stripping tank. If a stripping tank is installed a procedure for stripping using the equipment shall be prepared and practiced. If a stripping tank is not installed an alternative method of stripping shall be defined and practiced.

15.3.70 In conventional drilling operations it shall be possible at all times to disconnect from the string leaving a manually operated, full opening valve on the string.

15.3.71 During any top hole drilling operations prior to installing the BOP, a non-ported float valve shall be run in the drill string Bottom Hole Assembly (BHA) as a protection against shallow gas influx up the drill string.

15.3.72 Connections rated 3,000 psi and above shall not be threaded except as permitted in API RP53.

15.4 Wireline Operations

General Requirements

This section applies to well service operations performed with slickline, braided line or conductor line with or without a X-mas tree in service.

Configuration: Well Control Equipment

15.4.1 As arranged from top to bottom, the minimum BOP configuration for stacks used on wells where a surface pressure up to and including 5,000 psi is possible, shall be:

- Rated high-pressure, pack-off, stripper, or grease head with line wiper
- Lubricator of sufficient length to allow retrieval of the whole tool string, including items which may be retrieved from the well above the upper most tree valve or wireline BOP
- One set of wireline valve rams for slickline, or dual wireline valve rams for braided and conductor line, suitable or sized for each diameter wire passing through the wireline valve
- Pump-in sub or other means to kill the well while wireline valve rams are closed

15.4.2 Where a surface pressure of over 5,000 psi is possible, the following additional equipment shall be required:

- An additional wireline valve ram
- And, if the tree valve cannot cut and seal, a shear-seal BOP
- A risk assessment should be conducted to determine the potential for gas escape past the lubricator stuffing box and methods employed to mitigate

Well Control Processes

15.4.3 In the event that fished wireline or other tools of irregular size and shape are to be removed from the well, the number and size of the BOP's in the BOP stack up shall be based on a risk assessment and operational requirements.

15.4.4 Logging and perforating operations conducted without the installation of wireline pressure control equipment shall only be carried out under conditions where:

- The hole can be contained, monitored and controlled for the duration of the wireline operation
- Drilling/completion fluid provides the necessary active barrier
- Hole conditions are considered suitable for the tools that are to be run

15.4.5 If the lubricator connection is broken above an already fully tested riser and BOP a retest of the lubricator connection above the BOP for 5 mins to the maximum anticipated wellhead pressure, is sufficient to confirm integrity.

15.5 Coiled Tubing Operations

General Requirements

This section applies to well service operations with a coiled tubing service unit with or with out a X-mas tree in service.

Configuration: Well Control Equipment

15.5.1 All pressure containing connections from the well head up to the BOP's shall be flanged. Threaded connections may be used after a proper risk assessment and approval from the BU well control TA or designate on operations where surface pressures do not exceed 3,000 psi.

15.5.2 All annulus outlets shall be double valved.

15.5.3 As arranged from top to bottom, the minimum BOP configuration for stacks used on wells where a surface pressure up to and including 5,000 psi is possible, shall be:

- One high-pressure pack-off, stripper or annular type preventer
- Lubricator of sufficient length to allow retrieval of the complete bottom hole assembly, including items which may be retrieved from the well
- Hydraulically operated (with manual backup) triple – i.e. if triple is used one ram to be a dual purpose blind shear ram, quad or combination of BOP's with equivalent capacity and sized for the tubing to be used

15.5.4 BOP's shall have the following top down configuration:

- Blind rams
- Shear rams
- Slip rams
- Pipe rams

15.5.5 Where a surface pressure of over 5,000 psi is possible:

- An additional pipe ram shall be installed and used as contingency equipment additionally, the additional pipe ram shall only used in situations following failure of primary BOPE and not as an active barrier
- Combi BOP's shall not be installed
- A riser evaluation shall be undertaken to ensure that the combined mechanical and pressure loadings are within the operating limits of the supplied equipment

Well Control Processes

15.5.6 All relevant sections of this document shall apply to all coiled tubing operations.

15.6 Snubbing Operations

General Requirements

15.6.1 This section applies to well service operations with a snubbing unit with or with out a X-mas tree in service. Additionally this section applies to stand alone, and rig assisted snubbing operations.

15.6.2 Requirements set forth in this document are minimums and do not include the full range of considerations needed for every snubbing installation, i.e. HPHT, sub-sea, H2S, fishing operations etc. Each BU will develop and maintain guidelines and requirements specific to each snubbing application and approved by the relevant BU well control TA or designate.

Configuration: Well Control Equipment

15.6.3 As arranged from top to bottom, the minimum BOP configuration for stacks used on wells where a surface pressure up to and including 5,000 psi is possible, and the tubulars to be snubbed are not tapered; shall be:

- Stripper rubber or active stripper system, i.e. snubbing stripper bowl and rubber, annular or spherical type BOP
- Dual stripper rams equipped with a method to equalize and bleed off pressures between stripper ram components

Note: An annular or spherical BOP shall be not required if dual strippers are included in the BOP configuration, however dual stripper rams shall be required if an annular or spherical BOP is installed.

- An additional safety pipe ram shall be installed and used as contingency equipment. Additionally, the additional pipe ram shall only used in situations following failure of uppermost safety pipe ram and not as an active barrier

Where a surface pressure of over 5,000 psi is possible and the probabilities of tapered tubulars are anticipated additional equipment shall be installed:

- Blind or blind shear ram
- Flow / pump cross equipped with dual full opening valves on each choke and kill line for all stacks. The outer valve on the choke line shall be remotely activated. The outer valve on the kill line shall remotely operated and a non-return valve
- An additional pipe ram for each tubular described shall be installed and used as contingency equipment additionally, the additional pipe ram shall only used in situations following failure of primary BOPE and not as an active barrier

Well Control Processes

15.6.4 All relevant sections of this document shall apply to all snubbing operations.

15.6.5 All snubbing unit hydraulic functions shall not exceed the maximum operating tension loads of 80% and operating compression loads of 70% of minimum yield strengths for tubing string used.

15.6.6 Sufficient stack height shall be used to cover all tools to be run in and out of the well above the upper most contingent barrier.

15.6.7 Snubbing unit tongs shall be equipped with remote backups and safety snub line to secure and prevent tong movement during pipe make up and breakout.

15.6.8 Non-essential personnel shall be minimized from the snubbing floor during "pipe light" conditions.

15.6.9 Work floor egress route shall be predetermined and evacuation procedures practiced at regular intervals.

15.6.10 All relevant sections of this document shall apply to all snubbing operations.

15.7 Additional Considerations

Coring

15.7.1 All coring tool strings shall be equipped with a circulating sub above the core barrel.

15.8 Pressure Testing

General Requirements

15.8.1 All testing requirements not identified in this document remain as set forth in GP 10-45 Working with Pressure.

Pressure Testing of Well Control Equipment

15.8.2 In areas or fields where well design, hanger profile damage or tree leaks limit the use of plugs against which to test, the BOP's shall be shop tested prior to installation. The testing company shall provide the test charts and documentation. An additional shell test shall be performed once installed. The required accumulator test and function test shall be performed after rig up of well control equipment on the well and coincide with fourteen (14) day BOP pressure tests.

15.8.3 An accumulator test shall be carried out in accordance with the Accumulator Closing Test worksheet of API RP53 and the BP well control manual. Accumulator pre-charge pressure shall be recorded on the worksheet.

Also Refer to:

Section 8 Drilling & Completions Practices

Section 12 Safety Critical Software

Section 20 Well Operations

Section 24 Working with Pressure

SIGNIFICANT RISK SECTION – REFER TO ETPs GP10-15 & GP10-16

Section 16
Pore Pressure

16.1 Prediction

All Pore Pressure Prediction activity shall conform to Engineering Technical Practice GP10-15 – Pore Pressure Prediction.

16.1.1 A Single Point of Accountability shall be defined for the preparation of a pore and fracture gradient prediction for any given well.

16.1.2 The prediction of pressure for a BP well shall be prepared by a qualified individual who has been trained on BP practices and workflows.

16.1.3 All individuals preparing pressure predictions for BP wells shall have attended the BP 21st Century Pore Pressure Principles training course.

16.1.4 All individuals preparing pressure predictions for BP wells shall have been trained on the use of Presgraf.

16.1.5 The methods used to predict pressure shall be consistent with the BP pore pressure practices workflow (Appendix A).

16.1.6 Every well operated by BP shall have a pressure profile which shall include pore, sand fracture, shale fracture, and overburden pressures.

16.1.7 The pressure profile shall express the uncertainties associated with the prediction.

16.1.8 The pressure profile shall be updated to include all learning's from offset wells (offset pressure measurements, kicks, current state of depletion, etc.).

16.1.9 A validation review shall be conducted on any prediction subsequent to any major changes in the profile. The validation review shall have included at least one approved auditor and one qualified pore pressure expert from outside the asset (can be the same individual). Once the validation review is completed, the PPFG profile shall be frozen and further changes to the profile shall require management of change (MOC) process.

16.1.10 Software used to prepare pore and fracture pressure predictions shall meet BP safety critical software standards as defined in Section 12 of the BP Drilling and Well Operations Practice.

16.2 Detection

All Pore Pressure Detection activity shall conform to Engineering Technical Practice GP10-16 – Pore Pressure Detection.

16.2.1 A Single Point of Accountability (SPA) shall be defined for the delivery of a real-time pore and fracture gradient analysis for any given well.

16.2.2 The SPA shall be responsible to insure that all contractors and employees involved in the real-time detection of pressure meet the minimum requirements set out in this Engineering Technical Practice.

16.2.3 The real-time analysis of pressure for a BP well shall be prepared by a qualified individual who has been trained on BP practices, workflows, and relevant tools and applications to be used at the wellsite.

16.2.4 All individuals preparing real-time pressure analysis for BP wells shall have been appropriately trained on the use of the software used in the analysis.

16.2.5 Every well operated by BP shall have an ongoing assessment of the pore and fracture pressures during drilling operations.

16.2.6 Real-time pressure analysis prepared by contractors shall be monitored on a periodic basis using BP approved software to ensure that results are consistent with BP methodologies.

16.2.7 Personnel preparing real-time pressure analysis at the wellsite shall have a copy of the pre-drill pressure prediction for the well.

16.2.8 Personnel preparing real-time pressure analysis at the wellsite shall participate in a pre-operational meeting with the relevant BP personnel designated as the SPA for the pressure prediction to discuss the pre-drill prediction, methods planned for usage in detecting pressure, lines of communication, and responsibilities.

16.2.9 The SPA shall assure that all equipment used for pressure detection at the wellsite is available, in good working order, and calibrated as necessary.

Also Refer to:

Section 3 Health, Safety and the Environment – working hours at the wellsite

Section 12 Safety Critical Software

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-20

Section 17
Marine Geohazards

All shallow hazard assessment activity for offshore wells shall conform to Engineering Technical Practice GP10-20 – Marine Geohazards.

17.1 General

17.1.1 Marine Geohazard reviews shall include requirements for seabed clearance, environmental or archaeological review, and top-hole Geohazard review.

17.1.2 Upon, or prior to, access to a new offshore exploration area, SPU Exploration Management shall be informed of the fundamental risks to offshore operations from Marine Geohazards within the leased area.

17.1.3 Every standalone offshore well, well cluster, template, or drilling platform operated by BP shall have had a Shallow Hazards Assessment (SHA) produced that shall address the expected drilling risks to a depth of 200m below the preferred setting depth of the first pressure containment string or to a penetration of 750m below seabed, whichever is deeper.

17.1.4 The final SHA for a BP well shall be prepared and assured internally by a qualified individual making use of all the facilities at the disposal of a BP staff geoscientist and shall follow the protocol of the Offshore Site Investigation Manual.

17.1.5 An SHA shall state the expected risk of a hazard, shallow gas, water flow etc., being present by using the appropriate BP risk classification scheme for the particular hazard in question, see table below for shallow gas.

Classification	Description
High	An anomaly showing all of the seismic characteristics of a shallow gas anomaly, that ties to gas in an offset well, or is located at a known regional shallow gas horizon.
Moderate	An anomaly showing most of the seismic characteristics of a shallow gas anomaly but which could be interpreted not to be gas and, as such, reasonable doubt exists for the presence of gas.
Low	An anomaly showing some of the seismic characteristics of a shallow gas anomaly, but that is interpreted not to be gas although some interpretive doubt exists.
Negligible	Either there is no anomaly present at the location or the anomaly is clearly due to other, non-gaseous causes.

17.1.6 An offshore well shall not be sited over the top of a shallow gas anomaly reported to have a potential for having shallow gas presence greater than negligible without a documented operational risk review having been carried out.

17.1.7 A new offshore drilling location to be occupied by a bottom founded rig, barge, or platform shall be located on a high-resolution seismic survey line specifically acquired to address the new location. (Ref 17.3.1)

17.1.8 On recommencement of surface hole drilling an SHA shall be reviewed and re-issued for any well cluster, template or drilling platform where there has been a hiatus in drilling operations of greater than two years, or where the shallow casing plan, has been amended e.g. deepening of a casing shoe.

17.1.9 For a well that is the first BP well drilled in a basin, that has required Exploration Forum approval or where the fundamental Geohazard Level is high, and / or a critical geohazard issue has been identified, a qualified Hazards/pore pressure specialist shall be present aboard the rig to witness the drilling of the top-hole section.

17.1.10 A review shall be undertaken for an SHA for any well that has been shelved for a period of greater than a year to ensure: surface location, trajectory, target, or drilling plan has not changed and the SHA contents remain valid. Where changes are identified an MOC process should be applied.

17.1.11 If any anomaly is classified with a potential shallow gas presence greater than negligible by shallow hazards assessment, then the surface position of the well shall be relocated outside the anomaly to a location with negligible potential for shallow gas presence.

In the event that an acceptable location with negligible potential of shallow gas presence cannot be identified, then shallow gas shall be assumed present for purposes of well planning and risk mitigation. In such an event, a documented operational risk assessment shall be carried out, reviewed and approved. The document shall consider the following as a minimum:

- Potential presence of shallow gas
- Potential of shallow gas being abnormally pressured, if present
- Alternate location
- Possible use of pilot hole
- Rig type and capabilities
- Kill mud requirements
- Pump capacity
- Operational practices
- Riser or riserless configuration

17.1.12 Mutually agreed, rig-specific, shallow gas procedures shall be established between BP and the drilling contractor prior to the start of a well and shall cover foreseeable contingencies should shallow gas be encountered.

17.1.13 Shallow gas and diverter drills shall be held prior to spud of all wells and regularly until the first pressure containment string is set.

17.1.14 A shallow gas kick encountered prior to setting the first pressure containment string shall not be shut in. In such event of shallow gas flow, kill operations will immediately commence by pumping fluid into the well at the maximum sustainable pump rate.

17.2 Floating Drilling Operations

17.2.1 Wells shall be drilled riserless until the first pressure containment string has been set, unless:

- It is a government regulation to drill with a riser and diverter installed
- A recirculating mud system is required to drill the hole for surface casing

Prior to use of a riser to drill hole for surface casing, a documented risk assessment shall be performed to address associated risks of riser use.

17.2.2 The rig shall be maintained in a state of readiness to move off location whilst drilling surface hole. Where a riser is installed, procedures for well control and riser unlatch will be established in advance.

17.2.3 All floating drilling operations carried out with returns to the installation shall be carried out with a diverter system installed.

17.3 Bottom Founded, Barge and Platform Drilling Operations

17.3.1 A high-resolution seismic survey shall be performed for all locations. New locations shall always be chosen to fall upon a high-resolution survey line specifically acquired to address the location.

17.3.2 Wells shall be drilled with a diverter system installed for all hole sections after setting structural conductor or drive pipe and before setting the first pressure containment string.

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-25

Section 18
Waste & Fluids Pollution Risk Mitigation

All activity shall conform to Engineering Technical Practice GP10-25 – Waste and Fluids Pollution Risk Management.

18.1 HSSE and Process Safety Requirements

Audit and Assurance

18.1.1 Before commencing drilling and well operations, all rigs taken on contract and new installations owned by BP shall have a comprehensive containment audit carried out that considers the main areas detailed in Annex A. The SPU assurance process shall also confirm that environmental and waste management systems are effectively applied at the wellsite.

18.2 Waste Management Planning

18.2.1 Each SPU shall establish a waste management plan in accordance with EPR-4: Drilling Completions and Workover Discharges and EPR-11: Waste Management contained within OMS Practice – Environmental Requirements for New Projects (ERNP).

18.3 Fluid and Drilling Cuttings Management Procedures

18.3.1 Each SPU shall establish written procedures for the safe handling, containment, storage, transfer and treatment of DCWI fluids, chemicals and drill cuttings and for maintaining the integrity of the relevant key equipment and operations.

18.3.2 Procedures shall be in place that defines the roles, actions and responsibilities of those involved in Spill Prevention and the active recovery measures to be undertaken during any spill. Contractors shall develop and maintain a Spill Prevention plan that meets the requirements of the SPU plan.

18.4 Offshore Fluid Transfer Operations

18.4.1 The connection between the fluid transfer hose and the supply vessel for offshore hydrocarbon and brine transfers shall be a self-sealing, dry-break hose connector.

18.4.2 Preference shall be given to carrying out external fluid transfers during the hours of daylight. If operational reasons dictate that external fluid transfers are carried out during the hours of darkness then they shall be subject to a documented risk assessment which shall include environmental and safety considerations.

18.4.3 Fluid transfer during hours of darkness shall not commence without provision of sufficient illumination to allow the entire length of the transfer hose to be visually monitored from the installation.

18.4.4 If operational reasons dictate that simultaneous external fluid transfers of more than one hydrocarbon fluid product is required, it shall not take place until a full documented risk assessment has been made.

18.5 Fluid Containment

18.5.1 Any fluid transfer line, dump line or drain line that has the capability to discharge hazardous fluids to the environment shall be double secured (e.g. two valves or single valve closed, locked or capped).

18.5.2 Hazardous fluid storage tanks shall be adequately enclosed to contain any fluid discharge. All potential leak areas, including areas below pumps, filling stations, vents and overflow lines, shall provide adequate secondary containment to contain and facilitate the recovery of any leak.

18.5.3 There shall be secondary containment systems to prevent any leaks on the rig floor from entering the environment.

18.5.4 Any riser slip joint packer shall be provided with an alarm to indicate loss of pressure, and there shall be a secondary back-up to the primary means of energising the fluid containment packer element or a secondary packer.

18.5.5 Any riser emergency disconnect system shall incorporate a dual action activating system to prevent accidental activation.

18.5.6 Any flowline that passes over water or above an uncontained area shall be enclosed.

18.6 Preventative Maintenance of Key Equipment

18.6.1 A maintenance system shall include each specific bulk fluid transfer hose and section of hose, the supplier's certification, and to flag the maximum working life expiry dates of each hose.

18.7 Drill Cuttings Handling and Treatment

18.7.1 Where discharge to the environment is prohibited any drill cuttings transfer line, chute or dump line that has the capability to discharge to the environment shall be double secured.

18.8 Soil and Groundwater Impacts

18.8.1 To avoid soil and groundwater impacts onshore operations shall be designed in accordance with EPR-6: Environmental Liability Prevention of the ERNP OMS Practice.

18.9 Cuttings Disposal

Drill Cuttings Re-injection (DCRI)

18.9.1 Any drilled cuttings or waste fluids injection programme shall be conducted in a manner that assures long-term containment of the material within the targeted formation.

18.9.2 The materials suitable for injection shall be limited to the solid and fluid wastes generated during the well construction process. Any other waste streams should be separately assessed for their suitability for disposal by injection in terms of toxicity of waste stream, environmental benefit, current legal requirements, and any possible sub-surface interference effects.

18.9.3 An accurate record of inject waste shall be maintained.

18.9.4 A geomechanical sub-surface feasibility study shall be carried out prior to any injection project and the results peer reviewed by an appropriate expert in the Geomechanics community.

18.9.5 Continuous monitoring and regular back analysis of the injection operation shall be carried out to confirm that the reinjection is developing according to design expectations.

Cuttings Storage Pits

18.9.6 A site specific risk assessment shall be carried out to determine pit lining requirements and proper containment of any potential pollutants.

Other Disposal Methods

18.9.7 For all other disposal methods and requirements to reduce and eliminate the environmental impact of DCWI discharges and wastes refer to ERNP OMS Practice and ETP GP 10-25.

18.10 Mitigation of Oil Based Fluid Ignition Risks

Mitigation Plan

18.10.1 A plan shall be established to mitigate hydrocarbon ignition risks (see ISO 13702 for guidance).

18.10.2 The use of oil based drilling fluids requires that the Flash Point of the drilling fluid shall be at least 10°C/18°F higher than either the maximum anticipated flow line temperature of the fluid or the maximum anticipated ambient temperature, whichever is the greater.

18.11 Containment of Drilling, Completion, Wells and Intervention (DCWI) Chemicals and Wastes

18.11.1 Where there is a perceived risk of low level or naturally occurring radioactive material (LLRM or NORM) contamination, completion jewellery, tubing and samples retrieved from a well shall be checked for LLRM. An approved method of handling and disposal of NORM or LLRM shall be in place.

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-30

Section 19
Hazardous Materials

All well activity that may require the handling and management of Hazardous Materials shall conform to Engineering Technical Practice GP10-30 – Hydrogen Sulphide and Hazardous Materials in Well Operations.

19.1 Hydrogen Sulphide

19.1.1 No work shall be carried out which is liable to expose the wellsite operation to hydrogen sulphide (H2S) until a risk assessment of the potential impact of H2S is conducted. Where the risk of H2S occurrence cannot be effectively assessed, short term exposure shall be assumed and an appropriate level of detection and contingency resources shall be put in place. Given the unexpected potential for risk related to H2S all offshore drilling rigs shall have 6 SCBA workpacks, regardless of whether H2S is expected or not.

19.1.2 A contingency plan shall be established and followed for all exploration work and for any development and re-entry work where H2S concentrations in general workspace air could exceed 10ppm or iron sulphide is observed. Contingency plan shall address:

- Training
- Hazard zones, safe areas and escape routing
- Hazard characteristics, identification and alarms
- Response and control procedures including local impact assessment and release notification
- Minimum manning levels and personnel management during operations
- Minimum equipment levels for SCBA and related support and escape packs

19.1.3 All personnel working in or visiting an area during H2S operations shall be provided with training. Additionally, the BP designated site representative shall be trained in the implementation of any contingency plans.

19.1.4 Well operational planning for re-entry of any existing well shall consider or anticipate the potential for H2S presence due to degradation of the wellbore fluids.

19.1.5 Detection, safety and breathing equipment used on site should be specified, operated and maintained in accordance with the recommendations of RP 49. Minimum standards for drilling rig based detection shall required fixed electronic systems with sensors at shale shakers, rig floor and drillers work area. Two additional portable electronic multi sensor systems shall be available at the well site. For stand alone well intervention operations crews shall always have a properly calibrated multi sensor gas detector system available to assess well site conditions. (Multi sensor systems should cover H_2S, CH_4, O_2 and CO_2) Offshore Rigs shall carry a minimum of 6 x 30 minute ready to use SCBA work packs to allow emergency situations to be managed safely.

19.1.6 Prior to potentially hazardous formations being penetrated by or exposed to the wellbore, the BP designated site representative shall review the well operational plan and the contingency plan with the crews. Weekly onsite drills shall reinforce onsite well operational response.

19.1.7 H_2S safety equipment shall be fully available, tested and operational prior to drilling or exposing the hazardous formations or otherwise commencing H_2S operations. Breathing apparatus shall be in use upon detection or suspicion of H_2S concentration in workspace air reaching 10 ppm or more.

19.1.8 A job safety analysis shall be used to address the special hazards associated with trapped gas when pulling out of hole or otherwise recovering any drillstring, workstring, BHAs, wireline samples, bailers, interstitial wireline space, cores and core barrels back to surface, or opening of any lubricators.

19.1.9 Any sheltered or enclosed space adjacent to any circulating or storage tanks, pits or vessels which may be susceptible to H_2S accumulation shall not be entered without confined space controls, along with the tanks, pits or vessels themselves.

19.1.10 Operational controls for iron sulphide shall be in place. The plan should address use of scavengers to treat the material downhole and to manage the material at surface.

19.1.11 Where H_2S concentrations may exceed 100ppm, the contingency plan shall also clearly detail the decision on igniting or flaring the gas. The contingency plan shall include immediate, site-specific actions related to specific people, dwellings, vessels, aircraft, other installations and sites that are potentially impacted by any gas release away from the site.

19.1.12 Where well testing operations are conducted in known or potential H_2S environments additional stand alone electronic detection systems shall be installed. These systems shall be linked to activate the process system ESD systems upon detection of hazardous concentrations.

19.1.13 Refer to GP 10-30 for specific requirements for assessing the hazard in the subsurface; for developing the contingency plan; for more details on competency, training and drills; for well fluids and equipment design aspects; and, for contractor assessments.

19.2 Energy Logging

19.2.1 The energy logging contractor personnel shall manage all handling, transportation and operations with high potential energy materials (perforating, explosives, radioactive sources, chemical cutters, etc.) in accordance with their safety management system (SMS). The BP-designated site representative shall specifically discuss the contractors safety management elements related to the services being delivered with the contractor engineers prior to starting site based activities.

- Electric line detonators shall be either resistor type or radio frequency-immune
- Radio frequency isolation procedures shall be in place for every type of radio transmitting devices
- During material handling, all non-essential personnel shall be kept clear
- Written procedures and responsibilities for safe use, handling, storage, operations and contingencies, including misfire retrievals and fishing operations, shall be on site
- Permit to work shall be used where other contractors are present

19.2.2 At the wellsite, a person shall be designated in overall charge of, and responsible for, all energy logging operations. Operations shall only proceed when the designated person in consultation with the WSL and OIM considers the hole conditions present minimal risk to the safety of personnel, the environment and the installation.

19.2.3 The BP designated site rep should have basic oilfield explosives awareness training.

19.2.4 The BP designated site rep shall review the contractor crew's recent sleep and duty time for fitness to perform the expected activities.

19.2.5 The weak point of a stuck tool shall not be pulled without the express approval of the contractor's District or regional manager and the BP Drilling Manager.

19.2.6 Radioactive sources, detonators and explosives containers shall be kept separated and uniquely identifiable.

19.2.7 Radioactive material shall not be jettisoned offshore however radioactive materials should have radio beacons attached in case of loss overboard.

19.2.8 The following ETP (GP10-30) contains more detail on these requirements, some specific requirements for engineering planning, and requirements of the SPU for review of the contractors' safety management systems and related auditing.

19.3 Chemicals

19.3.1 For every drilling, completions and well operations treatment activity where hazardous chemicals (such as acids, caustics, poisons) are involved, detailed procedures shall be in place to address the following:

- Management and updating of all (MSDS) documentation on site ensuring availability of information in English and the most common local languages
- Training on appropriate use
- Personal protective equipment
- Handling, transportation, storage and disposal
- Emergency and medical treatment in event of exposure (e.g. eye wash stations, drench showers and antidotes/neutralising agents)
- Locations to include
  - Mud mixing hoppers
  - Mud pump area
  - Rig floor
  - Cement unit
  - Any acid or hazardous chemical mixing or pumping area

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-35

Section 20
Well Operations

All Well Operations activity shall conform to Engineering Technical Practice GP10-35 – Well Operations.

20.1 General

20.1.1 The Well Engineering Authority is accountable for appointing relevant technical authorities for delivery of well integrity and assurance throughout the complete lifecycle of each well.

20.1.2 The Well Engineering Authority shall provide assurance that all professional, supervisory, operational and maintenance staff involved in well activity are competent to do so.

20.1.3 The management and deployment of all intervention hardware (Pressure Control Equipment) shall be controlled.

20.1.4 SPUs shall develop a written philosophy for tubing and annuli management over full well life cycle.

20.1.5 SPUs shall develop process for the derivation and revision of formal Maximum Allowable Annulus Surface Pressure (MAASP) and Maximum Allowable Operating Surface Pressure (MAOSP) values and in some cases minimal allowable pressure recognising that annular fluids can change over time.

20.1.6 SPUs shall develop a written philosophy for tree and wellhead operations, maintenance, inspection and testing procedures over full well life cycle and establish and maintain service records.

20.1.7 A downhole safety valve (DHSV) shall be fitted below the seabed as a minimum, in every offshore platform well capable of naturally flowing hydrocarbons to surface. Acceptable leak rates shall be defined in the SPU well integrity procedures in line with requirement 7.6 of ETP. Failed DHSVs shall be replaced or substituted by an item which provides an equivalent level of well integrity in a safe and timely manner based on proper risk assessment and as deemed appropriate by the Well Engineering Authority.

20.1.8 SPUs shall develop a fit for purpose DHSV maintenance and testing programme when a DHSV is fitted.

20.2 Well Intervention

20.2.1 Prior to the commencement of any well intervention operations, the location shall be inspected to ensure it is safe for personnel and equipment during the planned operations.

20.2.2 Personnel and equipment shall be protected from exposed runs of wireline or coiled tubing and from any voids created by the removal of deck hatches and floor gratings.

20.2.3 During the period of well intervention, a single person shall be designated responsible for the well intervention operation.

20.2.4 Clear emergency shutdown procedures shall be in place, with which all drilling and well operations personnel are familiar.

20.2.5 All equipment subject to operational loading (sheaves, units etc) shall be load path certified and securely fastened or anchored to withstand the maximum expected forces during the operation of that equipment.

20.2.6 An assessment shall be made to determine if a wellhead/tree bending stress analysis is required depending on the nature of the well and subsequent well operations.

20.3 Well Intervention Operations

20.3.1 On production wells fitted with more than one tubing string all strings should be shut in during wireline rig-ups. Once rigged-up and tested, the other strings may be opened up until such time as the operations are complete and the equipment required to be rigged-down.

20.3.2 A recently calibrated and tested pressure relief valve of sufficient capacity, or an alternate safety mechanism, shall be included in the surface hook up on the fluid discharge line on any temporary or permanent pumping system that is capable of exceeding pressure ratings of any connected equipment.

20.3.3 A record of every wireline and coiled tubing toolstring (naming items, providing lengths, outside diameter thread type, fish neck sizes and any other salient points) shall be made prior to running in hole. This record shall be available at the wellsite throughout the time the toolstring is downhole.

20.3.4 Prior to the commencement of any well intervention operation, the swab valve turns to open and close shall be physically checked and noted.

20.3.5 If any well safety valve is held open by a temporary local control unit, that unit shall never be left unattended.

20.3.6 Pressures in the tubing and annuli shall be regularly monitored and recorded during all well operational activities.

20.4 Fishing

20.4.1 On completion of every well operation any tools or part of tools left downhole shall be accurately recorded and reported.

20.4.2 The configuration of BOPs in the rig up should be sufficient to close on both the fishing wire and the fished wire.

20.4.3 The lower BOP(s) should be fitted with rams and guides suitable for the fished wire.

20.5 Coiled Tubing Operations

20.5.1 BOPE shall be fully function and pressure tested upon installation and every seven (7) days, after any BOPE changes or CT change out unless documented stump tests can be provided by the service provider where as a shell test of BOPE shall be required upon installation to confirm connection integrity.

20.5.2 On any perforated well where a coiled tubing BHA is worked on bottom or where the coiled tubing is to be run without check valves, shear-seal BOPs shall be installed, to give a reasonable expectation that once cut, the coiled tubing will drop to regain control of the tree valves. When shear-seal BOPs are employed, all connections between them and the tree or wellhead shall be flanged and double valve isolated, thereby excluding elastomers from connections beneath these BOPs.

20.5.3 Shear seal and shear ram preventers shall be capable of shearing the coil and any lines within it, at all pressures up to the preventer's maximum anticipated working pressure. When lower shear seal preventers are equipped with single needle valve pressure equalising capability, the valve shall be replaced with a plug.

20.5.4 To ensure that it will always be possible to unlatch the riser from a subsea well, the lower riser assembly shall be capable of severing coiled tubing of the maximum wall thickness to be used as well as any wireline or control lines contained within, and provide a seal.

20.5.5 A choke manifold containing at least two adjustable chokes shall be installed, unless the normal production flowline is used through the tree and production manifold. In this case, the single production choke is sufficient.

20.5.6 Unless pressure deployment is used, the lubricator shall be of sufficient length to contain the BHA between the swab valve and the pack-off or between the downhole lubricator valve, where fitted, and pack-off.

20.5.7 Dual flapper check valves shall be run above the BHA on all strings unless the planned operation precludes their use. When not utilised, the programme or local standard operating practice should refer to a detailed and current assessment of risks, mitigations and contingency responses.

20.5.8 When elastomer seals are used they shall be made of a material intended for exposure to prevailing wellbore conditions.

20.5.9 The vapour pressure and flash point shall be known for all potentially flammable fluids. Special precautions should be in place.

20.5.10 Remaining coil tubing fatigue life shall be known and monitored prior to and during each job. A coil replacement philosophy should be in place commensurate with operating conditions. The position of all welds and the fluid exposure history shall be documented for each reel of tubing.

20.5.11 All coiled tubing operations shall not exceed the maximum operating tension loads of 80% and operating compression loads of 70% of minimum yield strengths for coiled tubing string used.

Also Refer to:

Section 15 Well Control

Section 24 Working with Pressure

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-36

Section 21
Breaking Containment

All activity on a completed well that requires containment to be broken shall conform to Engineering Technical Practice GP10-36 – Breaking Containment.

21.1 Breaking containment

21.1.1 Prior to breaking containment of any well control equipment such as the removal of a tree, BOP or any component, there shall be two independent mechanical barriers to flow fitted in all wells, capable of sustaining flow to surface.

- In each flow path there shall be two independent mechanical barriers isolating flow from the reservoir to surface
- In an offshore environment, each flowpath shall be isolated with one of the barriers installed below the seabed

21.1.2 Mechanical barriers shall be tested to the highest pressure to which they will be subjected. The two barriers shall be independently tested. Where practicable, these tests should be applied in the direction of flow. Where not practicable, the barrier should utilise seal design that permits verification from either direction.

- Tested mechanical barriers require to be confirmed as leaktight

21.1.3 Kill weight fluid may be used in place of one of the two mechanical barriers before breaking containment, if the well design or condition precludes the use of two independent mechanical barriers in each flow path, and the kill weight fluid meets the following criteria:

- Sufficient quantity of fluid may be placed in the wellbore to ensure that the fluid hydrostatic pressure exceeds the highest reservoir pressure
- The fluid level may be monitored and maintained throughout the period that the containment has been broken

21.1.4 These policy statements apply equally to tree valve repairs where the principle of double valve isolation shall be adhered to. (In an offshore environment, where wells are already fitted with an operable DHSV, there is no requirement to fit a barrier below the seabed as long as double valve isolation is intact).

21.1.5 A downhole safety valve that has been satisfactorily integrity tested for 30 minutes without leakage may be considered a barrier following the agreement of the SPU EA.

21.2 Pressure Control Equipment Rig Up

21.2.1 Leak tight isolation, using two or more valves, shall be used to allow for the removal of the tree swab cap or any other wellhead valved isolation.

a. Provided each valve meets an acceptable test criterion a combination of valves may be used to provide a leaktight seal prior to removing a tree swab cap or any wellhead part.

b. The practice of continually venting between the two isolation barriers is acceptable practice provided that it does not contravene local regulations and the vent is attended throughout the activity.

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-40

Section 22
Drilling Rig Audit and Rig Acceptance

All rig audit and rig acceptance activity shall conform to Engineering Technical Practice GP10-40 – Drilling Rig Audit and Rig Acceptance.

22.1 Onshore and offshore drilling units and workover units shall be subject to a formal rig audit to ensure compliance with this standard.

22.2 New onshore and offshore drilling units or upgraded offshore drilling units shall be subject to an integrated acceptance test (IAT).

22.3 Mobile offshore drilling units shall be audited to assess marine assurance in accordance with Group Marine Standard.

22.4 The segment engineering technical authority for rig acceptance/ design/movement shall approve the use of all rig auditors, other than the rig audit group, and the audit protocols utilised.

22.5 Follow-up audits shall be scheduled within 24 month from initial, or last, rig audit.

22.6 SPU shall make decision to accept or delay acceptance of a drilling unit on contract

22.7 SPU shall be accountable for closeout of audit recommendations.

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-43

Section 23
Moving and Securing MODUs

All MODU moving activity shall conform to Engineering Technical Practice GP10-43 – Moving and Securing MODUs.

23.1 Assessment of Capability to Operate at a Particular Site

23.1.1 Prior to contracting a MODU for a specific location the suitability of the unit to operate at that site shall be assessed by the wells team.

23.1.2 The assessment criteria for operation at a particular site shall be in compliance with ETP GP 10 – 43. A mooring analysis shall be performed for floating drilling operations prior to drilling with a moored MODU or in a new area or when the expected environmental conditions dictate this as being prudent.

23.1.3 The self-elevating unit deck elevation shall as a minimum be such that there is clearance between the underside of the deck and the extreme wave crest.

23.1.4 For a self-elevating unit the foundation assessment shall predict the degree of spud can penetration and potential leg punch-through. Self-elevating unit deployment shall not proceed unless this risk can be mitigated.

23.1.5 For a self-elevating unit seismic structural stability shall be assessed.

23.2 Metocean

23.2.1 For each MODU deployment site specific wind, wave and current criteria shall be derived using best practice procedures in accordance with ISO 19901-1 and verified by BP's Metocean specialists.

23.2.2 The 100 year return period conditions shall be used for storm survival assessment unless local regulation is more stringent.

23.3 Foundation

23.3.1 BP's geotechnical specialists should be consulted to determine if site-specific geotechnical investigation is necessary.

23.3.2 For self-elevating units a scour assessment shall be undertaken unless the foundation is rock or stiff clay.

23.4 Towing to Site

Note: Only applies if the rig is on contract to BP during the move to site.

23.4.1 The weather conditions likely to be encountered during the tow and transit times between appropriate locations for shelter should be identified and the tow planned to minimise risk to the MODU.

23.4.2 The number of personnel carried during the tow should be minimised whilst ensuring that the minimum manning requirements are maintained.

23.4.3 For a self elevating unit the tow route and procedures, including contingency arrangements, shall be approved by the SPU Marine Authority prior to any voyage. The passage plan for the tow shall include and identify ports of refuge and emergency jacking locations (where required) as a contingency against severe weather conditions.

23.5 Securing at Site

Mooring a Column-stabilized Unit or Monohull

23.5.1 The mooring design shall be in accordance with ISO 19901-7 or API RP 2SK.

23.5.2 The anchor pattern shall provide appropriate clearance of any subsea equipment, pipelines or other moorings; the clearance required should be site specific. In the event of any mooring lines crossing a pipeline or other mooring line the design shall include a risk assessment to determine the acceptability of the MODU mooring layout and appropriate protection measures.

23.5.3 Drag embedment anchor performance shall be verified by the load applied during installation. Suction embedment anchor performance shall be verified by calculation and installation in accordance with design requirements and approved by BP's geotechnical staff.

23.5.4 The condition of mooring systems and compliance with Recognised Classification Society (RCS) requirements shall be verified prior to deployment. The deployment of the mooring system without damage, rotated chain links or wire kinks and with connectors made up in accordance with the manufacturer's specification shall be verified.

23.5.5 No anchor shall be placed on the bottom until approval has been given by the BP Marine Representative.

23.5.6 MODU anchors shall not be placed within the anchor pattern of another barge/vessel without a full risk assessment and hazard analysis having being completed.

23.5.7 When recovering an anchor near a subsea obstruction, the anchor handling vessel position shall be accurately monitored at all times by surveyors onboard the vessel or MODU. The position of the anchor handling vessel should be monitored until the anchor is seen at the vessel's stern roller. When recovering across a pipeline, the anchor shall be brought on deck and secured. When a MODU is moored close to a production installation the MODU shall be winched to the 'stand-off' position prior to the recovery of anchors.

23.5.8 Risk assessment shall be conducted whenever handling heavy mooring equipment over subsea infrastructure to address dropped objects. A safe handling zone shall be established. (reference to Section 28 – SIMOPS).

Locating a Self-elevating Unit

23.5.9 A Survey Representative should be utilised on the MODU to provide assurance on the survey elements of the MODU positioning operations and to assist the BP Marine Representative. The Survey Representative is responsible for confirming whether the positioning objectives have been attained.

23.5.10 Moving a self-elevating unit alongside a production installation constitutes a major accident risk. Consequently a comprehensive risk assessment shall be performed, which shall address as a minimum the hazards from platform import/export risers, subsea pipelines and ongoing production operations.

23.5.11 Where a self-elevating unit is to be located alongside a production installation the minimum distance between hull and the extremity of the installation shall be not less than 1.5m after due allowance for inclination, rotation and lateral movement of the unit under jacking.

23.5.12 Where a self-elevating unit is to be deployed in an area with prior spud can holes on the sea bed, usually in close proximity to a production installation, appropriate measures shall be taken to avoid spud cans sliding into prior spud can holes.

23.5.13 For final manoeuvres alongside production installations, the self-elevating unit should be winched into position and not pulled into position by vessels. For moves alongside production installations physical gauging systems deployed over the stern should be used to give a visual indication of the MODU's position relative to the target.

Jacking a Self-elevating Unit

23.5.14 The condition of the jacking system and adequacy of jacking procedures shall be verified prior to deployment of the unit. This verification should be performed during the rig audit. When a unit is to be moved when no rig audit has been performed, for example an in-field move or a move to a different location, the well site leader shall verify that there are no known defects with the jacking system and that appropriate jacking procedures are available and will be utilised.

23.5.15 The self-elevating unit legs shall be preloaded to apply the 100 year storm load to each spud can. Depending on the ballast water capacity this may be undertaken in a single ballast transfer or by sequential loading of each leg. This should be undertaken with the hull close to the sea surface, in accordance with unit Marine Operations Manual, to control risks in the event of sudden penetration. For exploration wells not adjacent to fixed platforms where the ballast water capacity is not sufficient to preload to the full 100 year storm, but the soils are such that full foundation storm capacity will be reached with not more than 250mm settlement, then it is acceptable to proceed providing settlement monitoring and re-jacking is undertaken.

23.6 Dynamically Positioned MODU

Note: Only applies if the rig is on contract to BP during the move to site.

23.6.1 A DP rig move plan shall be prepared for every move where acoustic beacons or ground tackle needs to be relocated, and in particular when the BOP will remain in the water throughout the move.

23.6.2 The DP rig move plan shall include the location of the planned activity, all associated anchor patterns, existing pipelines, subsea infrastructure or other potential hazards in the area.

23.6.3 For any move over subsea infrastructure whenever there is anything hanging below the MODU keel, the production installation OIM shall approve the rig move plan and be notified immediately prior to commencement of the move. All infield moves shall be approved by production installation OIM.

23.6.4 When the BOP remains in the water during a rig move, the depth at the lowest point of the BOP shall be determined in relation to the seabed and any subsea infrastructure and confirmed at regular intervals during the move.

23.6.5 The rig move plan should evaluate available water depth not only at each location but also along the entire length of the intended track and the vicinity.

Also Refer to:

Section 28 Simultaneous Operations

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-45

Section 24
Working with Pressure

All pressure testing and high pressure pumping activity shall conform to Engineering Technical Practice GP 10-45 – Working with Pressure.

24.1 Pressure Testing

24.1.1 All tests shall include a low pressure test of 200 to 300 psi for 5 minutes before proceeding to the full pressure test.

24.1.2 For routine operational assurance testing of valves, manifolds and BOPs, a satisfactory pressure test is represented by the test pressure held for a minimum of 5 minutes after the pressure has stabilized.

24.1.3 For well integrity testing of casing and tubing strings, where system volumes are typically large, a satisfactory pressure test shall be carried out for a minimum undisturbed 30 minute monitoring period.

24.1.4 All tests shall be recorded on a chart or an electronic data logger.

24.1.5 Water is the preferred medium for pressure testing.

24.1.6 The volume of test fluid pumped and returned shall be monitored and recorded.

24.1.7 Pressure testing shall be performed by increasing the test pressure in a series of appropriate pressure increments.

24.1.8 The possibility of a test pressure leaking past a pack-off or test plug and being applied to a weaker element shall always be considered.

24.1.9 Prior to any pressure testing, the area shall be isolated.

24.2 Pressure Testing of Well Control Equipment

24.2.1 All subsea BOPs including annular BOPs shall be pressure tested on a test stump prior to deployment.

24.2.2 All well control equipment, except annular BOPs, shall be tested to the lowest of the following criteria:

(1) Maximum anticipated wellhead pressure to be encountered in the hole section plus an acceptable safety factor.

(2) 90% of casing internal yield pressure.

(3) Wellhead rated pressure.

(4) BOP rated pressure.

24.2.3 Annular BOPs shall be tested to a maximum of 70% of rated working pressure if not otherwise specified and endorsed by the SPU Well Control Technical Authority and approval by the Wells EA.

24.2.4 Pressure testing and full functional testing of the well control equipment shall be carried out to the pressures determined at intervals not normally exceeding 14 days. They shall be recorded on the Daily Drilling Report form.

24.2.5 This 14 day interval may be extended under exceptional circumstances, after an appropriate risk assessment, endorsement by the SPU Well Control Technical Authority and approval by the Wells EA.

24.2.6 All wellhead components and pressure-containing connections associated with the well control equipment shall be pressure tested in accordance with the requirements of this ETP GP10-45 upon installation or reinstallation.

24.2.7 An accumulator test shall be carried out as part of each regular BOPE test.

24.3 Pressure Testing of Tubulars

24.3.1 All surface, intermediate and production casings/liners shall be pressure tested prior to drilling out the shoe track or perforating.

24.3.2 Pressure tests shall not give rise to loads as described in continuing sections of GP10-45.

24.3.3 Pressure testing of structural/conductor casing shall not be required unless a subsequent leak-off test is necessary.

24.3.4 Surface and intermediate casings shall be pressure tested to the greater of that required for the anticipated leak-off test or formation integrity test (with appropriate test margin), or the surface pressure for the well control burst load case.

24.3.5 For development wells the minimum pressure test for production casing and liners shall be equivalent to the shut-in tubing pressure on top of the annulus completion fluids.

24.3.6 Production or test tubing should be tested to the maximum anticipated surface pressure plus an acceptable safety factor expected in the well.

24.3.7 Pressure testing of tubing is dependent of the completion design and should be considered as part of the running procedure.

24.3.8 Where internal pressure integrity is required liner laps shall be tested to a minimum of 500psi above the formation leak-off pressure at the covered casing shoe or sufficient to demonstrate pressure integrity if a greater operational loading may be expected.

24.4 High Pressure Pumping

24.4.1 Risk assessments shall be conducted on each and every well treatment activity where diesel, hazardous materials or chemicals are involved.

24.4.2 The effects of extremes of temperature on personnel, equipment, fluids, and additives shall be considered.

24.4.3 All personnel, including non-essential personnel, shall be assigned a position or work area prior to the pumping operation.

24.4.4 Safe areas and egress routes shall be established prior to pumping operations.

24.4.5 During all pumping and pressure testing operations, all personnel shall be shielded and positioned as stated in continuing sections of GP10-45.

24.4.6 When wellhead isolation tools are in use and the pumping operation is complete, the control panel for the isolation tool shall be tagged out until the service company is completely rigged down from the wellhead.

24.4.7 All treating iron / temporary pipe work shall have a mechanical integrity inspection tag attached, clearly stating the date of the last mechanical integrity test performed, and an identification number which references documentation of that equipment's inspection.

24.4.8 Line restraints may be used on liquid treating lines, but are not required. All energized treating lines shall be restrained from the pump discharge to the wellhead, and anchored at each end.

24.4.9 When pumping down a work string or completion equipped with a packer, the annular pressure shall be monitored and recorded on a chart during all pumping operations.

24.4.10 The annulus shall be pressure tested prior to the pumping operation to the maximum allowable annulus pressure.

24.4.11 Annular casing strings isolated from frac pressure with a packer shall be equipped with a pressure relief mechanism.

24.4.12 All pumps and treating equipment shall be tested to the maximum allowable treating pressure plus an acceptable safety factor, or the working pressure of the treating equipment, whichever is lower.

24.4.13 Where the treating line incorporates a check valve, the check valve shall be tested following the pressure test.

24.4.14 Pump trips / kick-outs are required on each pump.

24.4.15 An emergency pressure trip or shutdown system shall be used, which actuates when the pressure measured by the wellhead transducer exceeds the set point.

24.4.16 Maximum set pressure shall not exceed 95% of the maximum allowable treating pressure.

24.4.17 A manual emergency kill switch shall be easily accessible that kicks all pumps into neutral and/or shuts down the pump engines when actuated.

24.4.18 Pressure Relief Valves (PRVs) may be used on non-energized treating lines, but are not required.

24.4.19 PRVs shall not be used on any energized treating lines.

24.5 Remedial Pressure Operations

24.5.1 Methods of cleaning mud tanks should be identified that reduce exposure of personnel to potential risk from hose pressure and confined space entry.

24.5.2 All tank cleaning operations should be undertaken with equipment that can only be operated at or below pressures stated in the risk assessment for this activity.

24.5.3 Pump components, which are exposed to fluids being pumped during the life of the pump, shall be compatible with commonly utilized fluids.

24.5.4 Contractors that provide pressure pumping equipment should be expected to conduct regular maintenance checks on pumping equipment to confirm that all flow wetted components are in operational condition.

24.5.5 In situations where personnel are still required to operate a hose to clean tanks, a risk assessment of all components should be conducted.

24.6 General

24.6.1 Prior to commencing routine maintenance tasks for pumping operations, the pre-charge pressure in the pulsation dampener shall be observed for a period of fifteen (15) minutes to ensure the pre-charge pressure is static and there are no visible signs of leakage.

24.6.2 A risk assessment shall include detailed mitigation steps for pumping risks.

24.6.3 A detailed operational procedure shall be utilized to conduct any operation designated as "Working with Pressure".

24.6.4 An incident report shall be completed and documented within the Tr@ction reporting system following any failures resulting from working with pressure.

24.6.5 Emergency evacuation and rescue drills shall be developed and conducted prior to commencement of any operations which may result in failure from working with pressure.

24.6.6 The BP WSL shall verify operator's specific experience with relevant pumping equipment.

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-50

Section 25
Engineered Equipment

All Engineered Equipment shall conform to Engineering Technical Practice GP10-50 – Engineered Equipment.

25.1 This section covers only the permanently installed drilling and completion equipment listed in Table 1.

Table 1 – Engineered Equipment Covered

Description	Abbreviation
Surface Wellhead	**WH**
Surface Christmas Tree	**XT**
Connections	---
Surface-Controlled Subsurface Safety Valve	**SCSSV**
Annular Safety Valve	**ASV**
Landing Nipple	---
Crossover‡	**XO**
Liner Packer	---
Production Packer	---
Subsurface Barrier Valve†	**SBV**
Sand Screen	---

25.2 Critical engineered equipment shall be identified by means of a criticality assessment which accounts for the combined risk of HSSE, life-of-well integrity and business impact. Equipment shall be designated as critical when a Well Category of 2 or greater in Table 1 exists, at a minimum.

a. Critical equipment shall require the following:

i. Equipment Statement of Requirements (SOR)

ii. Designed in accordance with the applicable Industry specification. When an Industry specification does not exist, then equipment should be designed in accordance with a supplier's design specification that has been reviewed and accepted by BP.

iii. Qualified in accordance with the applicable Industry specification. When an Industry specification does not exist, then equipment should be qualified in accordance with a supplier's qualification procedure that has been reviewed and accepted by BP.

iv. BP may impose additional qualification test that exceed Industry specifications.

v. Design Review

vi. Manufactured, inspected and tested in accordance with the applicable Industry standard and to a BP Global QCP or the Integrity Assurance Specification (IAS), Examination Level 2.

vii. Factory Acceptance Test (FAT)

viii. Shop assembly and test quality plan for the inspection, make-up, and test of critical equipment assemblies.

ix. In addition, some critical equipment should require the following:

- Stack-up Tests
- Systems Integration Test (SIT)

b. Non-critical equipment shall be fit-for-purpose for the well service conditions from initial well construction, during the life-of-well and thru abandonment.

25.3 Engineered equipment, as identified in the following table, shall be designed, qualified, manufactured, inspected and tested in accordance with ETP GP10-50 and the requirements shown in table 4 embedded in the ETP document.

25.4 Only BP approved connections shall be used for field-end connections of engineered equipment.

25.5 Critical equipment that is integral to the production tubing string shall be analyzed and evaluated as part of the tubing design as per Section 13.

25.6 All engineered equipment shall be visually inspected, drift tested (if applicable) and function tested (if applicable) as close to the point of use as possible for handling damage to the equipment and threaded connections that could present problems during installation and/or over the life of the well.

25.7 All engineered equipment shall be accompanied with a supplier's installation procedure. BP well site procedures shall incorporate these procedures as applicable.

25.8 Operations during installation and well life shall not exceed the loads under which exposed equipment have been designed. A design evaluation shall be completed, should such an occurrence be contemplated.

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-60

Section 26
Zonal Isolation During Drilling Operations and Well Abandonment and Suspension

All zonal isolation activity shall conform to Engineering Technical Practice GP10-60 – Zonal Isolation and Abandonment During Drilling Operations.

26.1 Zonal Isolation

Minimum Requirement for Zonal Isolation

26.1.1 During Well Construction Zonal Isolation shall be designed to prevent:

- The development of Sustained Casing Pressure (SCP) during well operations
- Prevent contamination of any aquifers
- Prevent communication between any distinct permeable zones

Materials

26.1.2 Material selection should consider well service (and any likely changes) and the impact of well conditions on zonal isolation for the life of the well. If an alternative material (to cement) is used an evaluation should be conducted to ensure it meets criteria required to provide isolation until permanent abandonment.

Design Criteria

26.1.3 Zonal Isolation design criteria for cementing of primary casing strings to meet well integrity and future abandonment requirements, shall meet one of the following:

- 30 mTVD (100 ft TVD) above the top of the distinct permeable zone where the top of cement (TOC) is to be determined by a proven cement evaluation technique (Section 5.3)
- 300 m MD (1000 ft MD) above the distinct permeable zone where the hydraulic isolation is not proven except by estimates of TOC

For each well the actual TOC shall be recorded along with the method used for this determination. Where the actual TOC is below the plan, the TOC shall be reviewed with stakeholders for its impact on future well integrity, operability, suspension and abandonment operations.

26.2 Suspension and Temporary Abandonment

Suspension and temporary abandonment shall be designed to ensure zonal isolation for the duration of the suspension and permit safe re-entry of the well.

Number of Barriers

26.2.1 Two temporary barriers are required for isolation of moveable hydrocarbon bearing or overpresssured permeable sections from surface/seabed.

Verification of Barriers

26.2.2 The first barrier shall be pressure and / or inflow tested and tagged (if plug is set in openhole (OH) tagging only required), the second barrier shall be tagged or pressure tested.

26.3 Permanent Abandonment

The decision to permanently abandon or temporarily suspend a well shall be approved by the relevant Performance Unit Leader or their delegate and by the regulatory authorities.

Permanent abandonment shall be designed to protect aquifers, ensure isolation between distinct permeable zones and to prevent flow from them to surface or seabed.

- For hydrocarbon bearing permeable zones two permanent barriers are required from surface or seabed

For water bearing permeable zones one permanent barrier required from surface or seabed

Acceptable Barriers

26.3.1 Cement shall be the material acceptable for permanent abandonment.

Selection and Location of Permanent Barriers

26.3.2 Good cement verified to be 30 m TVD (100ft TVD) above a distinct permeable zone shall be considered an acceptable permanent barrier.

To constitute a permanent barrier the annular cement around the plug setting depth should meet annular isolation requirements positioned to provide full lateral coverage of the well. Cement plugs shall be set at a point where formation strength is capable of controlling the pressure from the formations it is isolating.

Barrier Verification

26.3.3 Barriers can be verified by weight testing and/or pressure testing (positive and/or inflow). All primary barriers should be weight tested and pressure tested except:

- In OH where only weight testing is permitted (OH cement plugs cannot be accepted as the only barrier)
- When the plug has been set on a permanent mechanical barrier (when pressure testing is only required)

Weight testing should be up to at least 15K lb (6.8 Tonne). Pressure testing shall be 0.1psi/ft (2.26 KPa/m) above the leak off test (LOT) (or predicted fracture gradient at the shoe) or 500 psi (3.45 MPa) whichever is the greater. The pressure test is acceptable where pressure drop is <10% over 15 mins.

26.4 Special Considerations

Permafrost Cementing

26.4.1 The plugging material shall develop the required properties before freezing and not impact permafrost during setting.

Aquifers

26.4.2 Fresh water aquifer should have annulus barriers extending a minimum of 30 m (100ft) TVD beneath the base of permeable interval containing the fresh water and 30 m (100ft) TVD above the top of the permeable fresh water interval or to surface. Plugs set inside pipe should extend 30m (100ft)TVD above the aquifer and provide a seal extending laterally across the entire well.

Control Lines

26.4.3 An abandonment cement plug with open control line through it shall not be accepted as a permanent barrier.

Corrosive Environments

26.4.4 The potential for casing corrosion shall be accounted in the plugging plan.

SIGNIFICANT RISK SECTION – REFER TO ETP GP 10-70

Section 27
Completion/Workover Riser (CWOR) Systems

The design and operation of all Completion /Workover Riser Systems shall conform to Engineering Technical Practice GP10-70 – Completion/Workover Riser Systems.

The design and operation of all Completion/Workover Riser System shall also conform to Engineering Technical Practice GP 78-33 – Design and Operation of Completion/Workover Riser Systems which has been developed as a supplement to ISO 13628 Design & Operation of Subsea Production Systems, Part 7 – Completion/Workover Riser Systems.

27.1 CWOR Systems

27.1.1 The ETP is limited to CWOR Systems manufactured from low alloy carbon steels.

27.1.2 Risers fabricated from special material such as Titanium, composite materials and flexible pipes are beyond the scope of this document.

27.1.3 The Standard shall apply to all new systems and shall be applied to modifications and operation of existing systems, particularly when they are re-deployed at different locations and from different vessels.

27.2 Description of CWOR Systems

A **Completion Riser** is used to run the tubing hanger and tubing through a drilling riser and BOP into the wellbore. It may also be used to reconnect to a tubing hanger for well re-entry through a drilling riser and BOP.

A **Workover Riser** is typically used in place of a drilling riser to re-enter the well through the subsea tree in open water, and may also be used to install the subsea christmas tree.

Both riser types provide communication between the well bore and the surface equipment. Both resist external loads and pressure loads and accommodate tools for drilling and completion operations.

The **Completion Riser** is exposed to external loading such as curvature of the drilling riser, especially at the upper and lower joints (ie Flex-joint and Ball-joint).

The **Workover Riser** is exposed to ocean environmental loads such as hydrodynamic loads from waves and currents, in addition to vessel motions.

Note that Completion/Workover Riser Systems are considered to be Safety Critical Equipment.

27.3 Scope of Supply

Specific CWOR System equipment covered by the above referenced documents is as follows:

- Riser Joints
- Connectors
- Workover Control Systems
- Surface Flow trees
- Surface Tree Tension Frames
- Lower Workover Riser Packages
- Lubricator Valves
- Retainer Valves
- Subsea Test Trees
- Shear Subs
- Tubing Hanger Orientation Systems
- Swivels
- Annulus Circulation Hoses
- Umbilical Clamps
- Handling & Test Tools
- Tree Cap Running Tools

The ETP outlines the following topics which are prescribed in more detail in ETP 78-33 and ISO 13628:

- System requirements
- Functional requirements
- Design requirements
- Materials & Fabrication
- Testing requirements
- Marking, Storage & Shipping
- Documentation

27.4 System Requirements

The CWOR System engineering shall be performed to ensure CWOR Riser System compliance with the provisions of the ETP, ISO referenced standards and regulatory requirements. System engineering shall, as a minimum, include the following:

- Establishment of a design basis
- Establishment of the system definition
- System design
- System review
- System verification

The CWOR System shall be designed to meet the following requirements:

- Regulatory requirements
- Barrier requirements
- Purchaser specification requirements
- Design basis
- Design principles
- Operational principles
- Safety principles
- Operational requirements
- System and component functional requirements

The CWOR System definition shall as a minimum be described in terms of the following:

- System description
- System schematics
- Riser modes of operation
- Workover Control System modes of operation

Refer to ETP GP10-70 for other ETP's applicable to CWOR System selection and specification.

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-75

Section 28
SIMOPS

All simultaneous operations activity shall conform to Engineering Technical Practice GP10-75 – Simultaneous Operations.

Management Accountability

28.1 The control of Simultaneous Operations is a line responsibility and SPUs shall clearly identify the roles and responsibilities of the personnel who are accountable for delivering the necessary safety and integrity performance in the wells arena.

Risk Assessment

28.2 An assessment of operations shall be performed on each facility or field in order to identify the possible risks associated with simultaneous operations across the complete range of well activities. Appropriate constraints or mitigating actions and specific procedures shall be applied.

The consequences of failure shall be evaluated from the perspective of at least four criteria: safety, environment, economic and reputation.

Identification and Assessment

28.3 Following the Risk Assessment and prior to commencing any well activity, or any activity performed at a well site, all identified hazards should be considered as being in one of two categories. These are Major Accident Hazards and Local Interface Hazards.

Major Accident Hazards

28.4 Major Accident Hazards as a result of Simultaneous Operations shall be identified so that controls and mitigations can be put in place before the activity takes place.

Note: only the hazards that are raised as a result of simultaneous operations should be considered. Single activities and many of these hazards and mitigations may be covered by a separate ETP (e.g. Moving and Securing MODUs).

SIGNIFICANT RISK SECTION – REFER TO ETP GP10-80

Section 29
Well Testing

All well testing and clean up operations shall be designed to conform with GP 10-80 (Well Testing ETP).

29.1 The equipment programmed for the Well Testing or Clean Up operations shall be designed to be able to safely control the maximum potential pressures that the reservoirs may be able to generate.

29.2 Timely HAZOP/HAZID reviews shall be conducted covering the Well Testing/Clean Up equipment and operations plans for all newly programmed activities. A process safety specialist should be involved in this review. However a generalised review covering a programme of similar operations on multiple wells is acceptable as long as an appropriate MOC programme addresses potential variations.

29.3 A detailed programme for Well Testing or Clean up operations shall be prepared for each well.

29.4 All installed Temporary Process Equipment shall be checked to confirm compliance with the relevant documented P&ID (Process and Instrumentation Diagram).

29.5 BOP's and associated equipment shall be tested immediately prior to running the test string.

29.6 All connections within test strings or completion strings with packers shall be tested to the maximum anticipated pressure, plus a safety margin, prior to flowing the well.

29.7 The test string shall be designed to allow effective well kill in the event of any potential failed closed valve within the string. The test string shall include the facility to allow the string contents to be circulated or bullheaded prior to pulling out of hole.

29.8 All surface well testing or completion equipment potentially exposed to high operating pressures shall be pressure tested to the maximum anticipated pressure, plus an acceptable safety margin, prior to flowing the well.

29.9 All other process equipment shall be tested to its rated working pressure or to an appropriate test pressure that will not actuate installed relief valves.

29.10 Test lines, relief lines, process equipment and all relevant temporary fittings shall be securely anchored. Particular attention shall be given to line fixing at each end and along their length.

29.11 Relief lines shall be designed to accommodate the maximum potential fault flow rate without exceeding their own pressure rating.

29.12 Emergency Shut Down systems shall be function tested and confirmed operational prior to the start of well flowing.

29.13 The air supply to burners shall be independent of the rig air supply. Non return valves should be fitted between the compressors and burner head.

29.14 Unlatch equipment deployed for floating rig operations shall be function tested prior to running tools into the well.

29.15 Subsea test trees and test string deployed safety valves shall be capable of shearing all coiled tubing and wireline to be run through the test string.

29.16 The capability of the BOP's to shear the Sub Sea tree slick joint shall be determined and suitable safeguards installed to prevent the test string being pulled to position non shear-able assemblies across the shear rams.

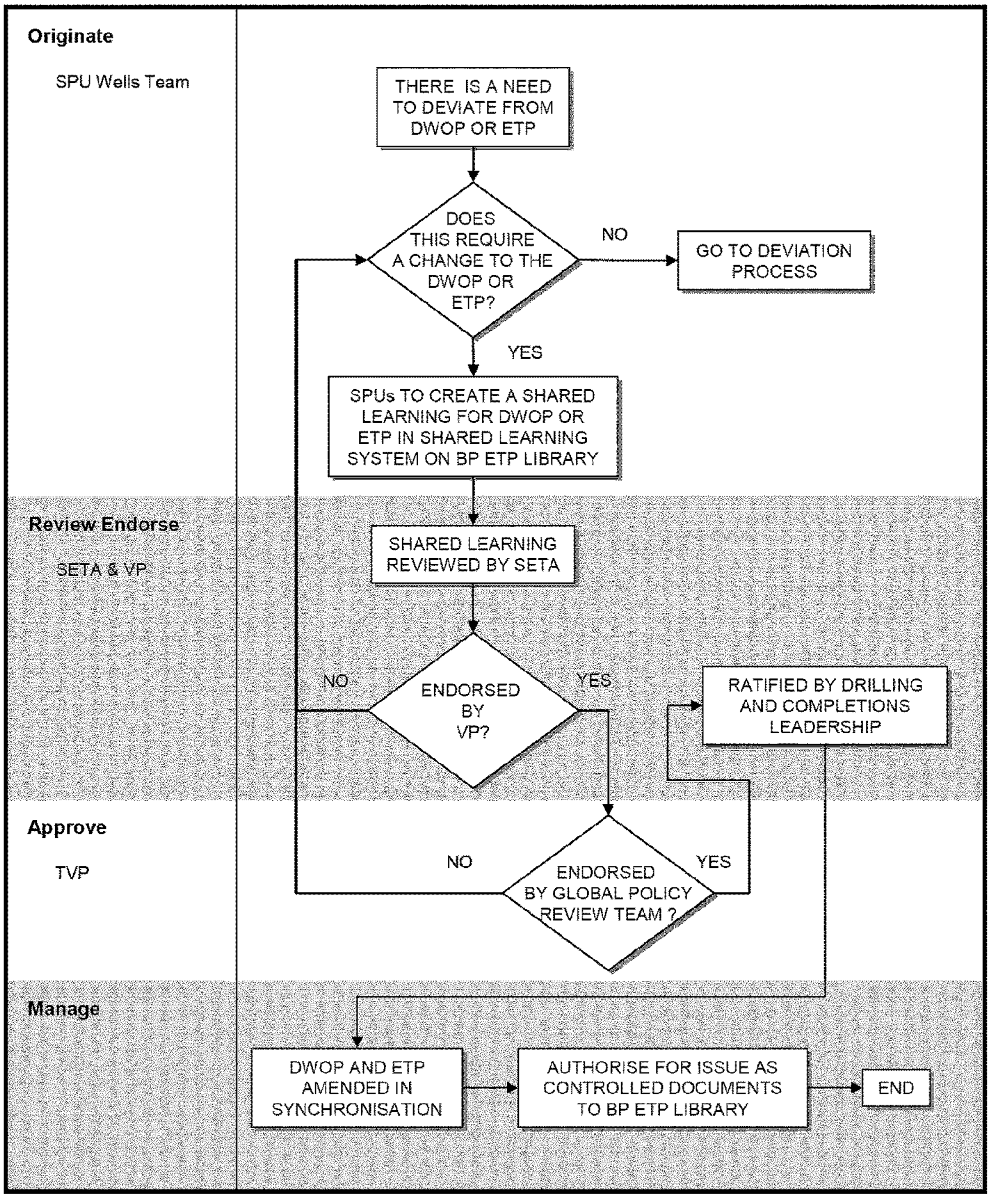
29.17 During testing sufficient main power, well control and installation services shall be available and on line to service unplanned or emergency conditions that may occur during the test.

29.18 Nitrogen used to pre-charge DST tools or samplers shall be certified oxygen free or analysed on site to confirm quality before use.

29.19 All rig installed and temporary gas detection systems and safety equipment shall be certified fit for use prior to the start of flow.

29.20 After completing well testing or clean up operations reasonable steps shall be taken to ensure that the well conditions are safe to allow tripping out of the hole to commence.

Addendum 1
Practice Amendment/Revision Flow Map



Addendum 2
Practice Amendment/Revision Process

It is the intention that DWOP and the associated ETPs will be reviewed on a regular basis over time. Since the documents closely relate to each other, it is necessary that they be amended in synchronisation to ensure that DWOP and the ETPs are always aligned.

If you find that in the course of using either DWOP or the ETPs that a revision or amendment is necessary, you should take the following steps:

1. Go to the BP Engineering Technical Practice Library at:

   http://etplib.bpweb.bp.com/sitePreferences.jsp

2. Click the GO button in the Browse panel.
3. Select the specific ETP from Category 10 of the library.
4. Once the document is opened, you will see an invitation to:

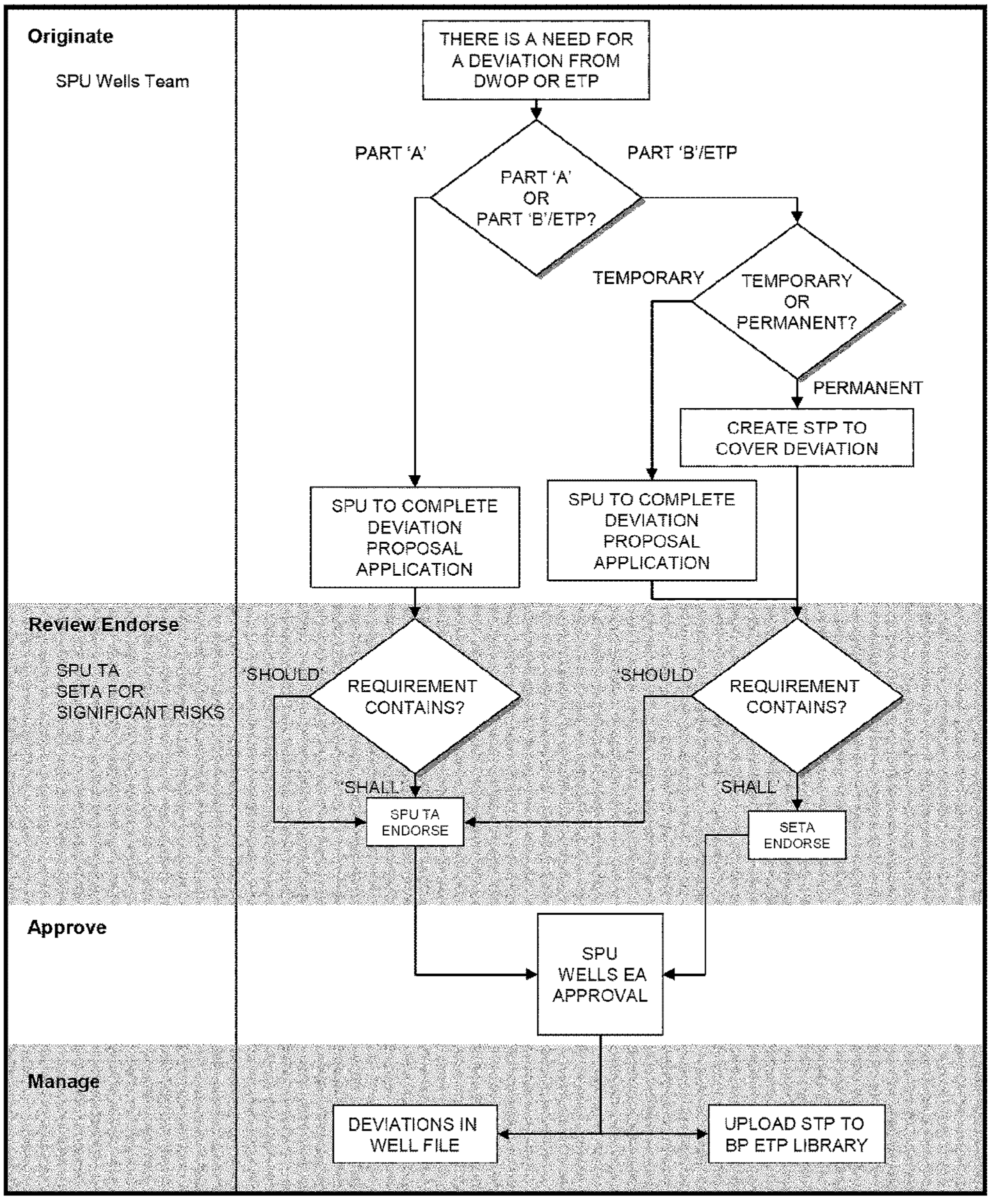
   'Create a **Shared Learning** or create a **Comment** relating to this document'

5. Select either option and complete the form as required.

The Shared Learning or Comment will be directed by the system to the current SETA for that ETP and will remain in the system until it has been dealt with accordingly.

The SETAs will maintain a record of all suggested changes in the SLS (Shared Learning System) and action them at the next amendment exercise authorised by the TVP.

Addendum 3
Practice Deviation Map



Addendum 4
Typical Practice Deviation Proforma

Note: That regional variation may be permitted, under authority of VP, to reflect local organisation.

<table>
<tr><td>SPU AND FIELD</td><td colspan="6"></td></tr>
<tr><td>Well Number or Development</td><td></td><td>Practice Requirement Number</td><td></td><td>Deviation Reference No</td><td colspan="2"></td></tr>
<tr><td>SUBJECT (Short one line description)</td><td colspan="6"></td></tr>
<tr><td>PROPOSED DEPARTURE FROM PRACTICE
(Include full identification of requirement and reason for request)</td><td colspan="6"></td></tr>
<tr><td>RISK ASSESSMENT
(What additional risks does this incur, and what is being done to minimise those risks)</td><td colspan="6"></td></tr>
<tr><td>DURATION
(Timing of specific well, or field-wide application and duration of exposure)</td><td colspan="6"></td></tr>
<tr><td>SIGNATURES
(Printed name, signature, date)</td><td colspan="2">Name</td><td colspan="2">Signature</td><td colspan="2">Date</td></tr>
<tr><td>ORIGINATOR
(SDE, DS, Wells Manager)</td><td colspan="2"></td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>REVIEW
(Technical Authority)</td><td colspan="2"></td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>ENDORSEMENT
(SETA – Significant Risk requirements)</td><td colspan="2"></td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>APPROVAL
(Appropriate to Language)</td><td colspan="2"></td><td colspan="2"></td><td colspan="2"></td></tr>
</table>

Addendum 5
Group and Segment Defined ETPs

Group Defined

No	Process Safety – Procedures and Processes – 7
GP 24-03	Concept Selection for Inherently Safer Design
GP 32-30	Inspection and Testing of Equipment In Service – Management Principles
GP 43-49	Pipeline Integrity Management Systems (PIMS)
GP 48-01	HSSE Review of Projects
GP 48-02	Hazard and Operability (HAZOP) Study
GP 48-03	Layer of Protection Analysis (LOPA)
GP 48-50	Major Accident Risk Process

Segment Defined

No	Process Safety – Procedures and Processes – 12
GP 04-30	Design and Location of Occupied Permanent Buildings Subject to Blast, Fire, and Gas Hazards on Onshore Facilities
GP 04-31	Design and Location of Occupied Portable Buildings for Onshore Locations
GP 04-32	Protection of Personnel from Explosion, Fire, and Toxic Hazards on Offshore Facilities
GP 24-20	Fire and Explosion Hazard Management of Offshore Facilities
GP 24-21	Fire Hazard Analysis
GP 24-22	Gas Explosion Hazard Analysis
GP 35-20	Isolation of Equipment for New Plant
GP 24-23	Active Fire Protection – Offshore
GP 44-25	Guide to Depressurization
GP 44-34	Siting of Buildings on Wellsites
GP 44-60	API RP 500 Area Classification
GP 44-65	IP 15 Area Classification
GP 44-70	Overpressure Protection Systems
GP 44-80	Design Guidelines for Relief Disposal Systems
	Mechanical Integrity – 8
GP 06-10	Corrosion Management
GP 06-14	Erosion Control
GP 06-20	Materials for Sour Service
GP 06-25	Design for the Prevention of Corrosion under Insulation and Fireproofing (CUI and CUF)
GP 06-70	Corrosion Monitoring
GP 32-20	Site Inspection, Testing, and Commissioning of Plant and Facilities
GP 32-40	In Service Inspection and Testing – Common Requirements
GP 36-15	Material Selection and Specification for Topsides
	Instrumentation, Control and Electrical – 4
GP 12-60	Hazardous Area Electrical Installations
GP 30-80	Safety Instrumented Systems (SIS) – Implementation of the Process Requirements Specification
GP 30-81	Safety Instrumented Systems (SIS) – Operations and Maintenance
GP 30-85	Fire and Gas Detection
	Pipeline – 3
GP 43-17	Pipeline Risk Management
GP 43-50	Pigging, Pig Launchers, and Receivers
GP 43-52	Inspection and Integrity Assessment of Pipeline Systems

Addendum 6
Glossary of Definitions, Terms, Abbreviations and TLAs

Topic	Definition
Drilling and Well Operations	Well construction, drilling, testing, completion, workover, and intervention activities related to wells, performed under the control or supervision of BP, or on behalf of BP as operator.
Barrier	A means to provide for containment of flow or pressure for the duration of its installation.
Surface Hole	Hole section drilled to enable the first casing string upon which the wellhead and BOPs are installed to enable shut-in.
Safety Critical	A safety critical element is a complete system, or part thereof, that could, if it failed, cause or contribute substantially to a major incident or accident, or is designed to prevent, detect, control or mitigate a hazard with the potential to cause property damage, personal injury, environmental damage or loss of reputation.
HPHT	High Pressure, High Temperature: When conditions (A + B) or (A + C) as defined below are expected. A Where the undisturbed bottomhole temperature at prospective reservoir depth or total depth is greater than or equal to 149°C (300°F). B The maximum anticipated pore pressure of any porous formation to be drilled exceeds 0.8psi/ft. C When the maximum anticipated surface pressure is greater than or equal to 10,000psi.
Defined Practice	A course of action whose primary function is to set forth an organisation's principles and to provide the structure within which personnel shall work and make decisions. Practice statements set forth the minimum requirements for all drilling and well operations and shall be complied with unless specific deviation has been approved.
Recommended Practice	BP best practices that have evolved over many years for satisfactory performance. These are not mandatory but require justification for deviation.

Topic	Definition
Guidelines	Statements which describe an approach to performance of an operation. They represent practices which are preferred based on past experience.
Business Unit Wells Manager	The generic title used in this document to describe that position who has Business Unit responsibility for drilling and well operations. This position should be formally agreed within each Business Unit.
Designated Company Representative	The onsite BP representative, eg Wellsite Leader, Drilling Supervisor, Drilling Foreman, Offshore Well Engineer, Well Service Supervisor, nominated contractor supervisor, Wellsite Production Engineer, etc.
Drilling or Well Engineer	The Business Unit well operations or drilling engineer who has office responsibility for drilling or well operations.
Designated Contractor's Representative	The onsite contractor's representative of any drilling or well operations crew, eg Offshore Installation Manager, Toolpusher, Superintendent etc.
Non-routine Operations	Operations which do not ordinarily take place, or those operations which have a greater than normal consequence or probability of occurrence of unplanned events.
Well Intervention	Any activity that involves entering the pressure containing envelope of the well.
Underbalanced Drilling	Drilling Operations conducted where the hydrostatic head of fluid in the wellbore is intentionally lower than bottomhole formation pressure.
Well Control Equipment	Well control equipment includes the diverter system, BOP stack, high-pressure riser, BOP control system, wellhead, wellhead connector, casing, kelly cocks, kelly hose, drillstring safety valves, the kill and choke lines, kill and choke manifold, mud gas separator and all associated pipework and valves.
First Pressure Containment String	The first string of casing set for the purpose of containing wellbore pressure and incorporating use of BOP equipment to contain such pressure.
Shallow Gas	Shallow gas is defined as any gas present in the section above setting depth of the first pressure containment casing string.
Exploration and Production Technology (EPT)	The general term used in this document for the business stream entity with responsibility for the provision of specialist technical expertise.

APB	Annular Pressure Build-up
API	American Petroleum Institute
BHA	Bottom Hole Assembly
BOP	BlowOut Preventer
DC&W	Drilling Completion & Wells
DCRI	Drill Cuttings Re-Injection
DCWI	Drilling Completions & Well Intervention
DHSV	Downhole Safety Valve
DP	Dynamic Positioning
DWOP	Drilling & Wells Operations Practice
EA	Engineering Authority
ETP	Engineering Technical Practice
ERNP	Environmental Requirements for New Projects
eWLM	Electronic Well Location Management
FAT	Factory Acceptance Test
GDP	Group Defined Practice
GE	Group Essential
H_2S	Hydrogen Sulphide
HOD	Head of Discipline
HSSE	Health, Safety Security and Environment
IADC	International Association of Drilling Contractors
IAS	Integrity Assurance Specification
JORPs	Joint Operating & Reporting Procedures
LLRM	Low Level Radioactive Material
LOMS	Local Operating Management System
LOT	Leak Off Test
MAASP	Maximum Allowable Annulus Surface Pressure
MAOSP	Maximum Allowable Operating Surface Pressure
MOC	Management of Change
MODU	Mobile Offshore Drilling Unit
OH	Open Hole
OIM	Offshore Installation Manager
OMS	Operating Management System
PPFG	Pore Pressure Fracture Gradient
QCP	Quality Control Plan
RCS	Recognised Classification Society

SCP	Sustained Casing Pressure
SHA	Shallow Hazards Assessment
SIT	Systems Integration Test
SOP	Site Operating Practice
SOR	Statement of Requirements
SPA	Single Point Accountability
SPU	Strategic Performance Unit
STP	Site Technical Practice
TOC	Top of Cement
TVD	True Vertical Depth