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DWGOM
GP 10-45-1

Working with Pressure (Supersedes GP 10-45)

DWGOM
SITE TECHNICAL PRACTICES

Introduction

The introduction to this ETP mirrors section 24 of the revised DWOP.

All pressure testing and high pressure pumping activity is considered "Working with Pressure" and shall conform to Engineering Technical Practice DWGOM GP 10-45-1.

1. Pressure Testing

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

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.

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

1.4 All tests should be recorded on a chart or an electronic data logger.

1.5 Water is the preferred medium for pressure testing.

1.6 The volume of test fluid pumped and returned should be monitored and recorded.

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

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

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

2. Pressure Testing of Well Control Equipment

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

2.2 All well control equipment, except annular BOPs, should 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.

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.

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

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.

2.6 All wellhead components and pressure-containing connections associated with the well control equipment should be pressure tested in accordance with the requirements of this ETP DWGOM GP 10-45-1 upon installation or reinstallation.

2.7 An accumulator test should be carried out as part of each regular BOPE test.

3. Pressure Testing of Tubulars

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

3.2 Pressure tests should not give rise to loads as described in continuing sections of DWGOM GP 10-45-1:

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

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.

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

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

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

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.

4. High Pressure Pumping

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

4.2 The effects of extremes of temperature on personnel, equipment, fluids, and additives should be considered.

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

4.4 Safe areas and egress routes should be established prior to pumping operations.

4.5 During all pumping and pressure testing operations, all personnel shall be shielded and positioned as stated in continuing sections of DWGOM GP 10-45-1.

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

4.7 All treating iron / temporary pipe work should 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.

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

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

4.10 The annulus should be pressure tested prior to the pumping operation to the maximum allowable annulus pressure. (Note: the annulus referred to here is the workstring by casing, not any other casing annuli – which are not accessible in subsea wellheads.)

4.11 Annular casing strings isolated from frac pressure with a packer should be equipped with a pressure relief mechanism.

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

4.13 Where the treating line incorporates a check valve, the check valve should be tested following the pressure test.

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

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

4.16 Maximum set pressure should not exceed 95% of the maximum allowable treating pressure.

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

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

4.19 PRVs should not be used on any energized treating lines.

5. Remedial Pressure Operations

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.

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.

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

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.

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.

6. General

6.1 Prior to commencing routine maintenance tasks for pumping operations, the pre-charge pressure in the pulsation dampener should 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.

6.2 A risk assessment should include detailed mitigation steps for pumping risks.

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

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

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

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

Foreword

This is the first issue of Engineering Technical Practice (ETP) BP DWGOM GP 10-45-1. This Group Practice (GP) is based on parts of the BP Drilling and Well Operations Practice (BPA-D-001), and for the subject matter covered herein, supersedes that document.

Working with pressure is a routine activity for drilling, completions and well operations personnel. So common place is this activity that occasionally personnel can become complacent and the risks of working with pressure can be underestimated resulting in a significant number of incidents, many resulting in damage to facilities or wells, but more importantly some resulting in injury or even fatalities.

The purpose of this ETP is to pull together guidance and best practice when 'Working with Pressure' that has been learned over the years and thereby reduce the number and severity of incidents sustained.

Everyone "Working with Pressure" will know that:

Force = Pressure x Area

Most recognise that high pressure can develop significant forces, but many incidents result from relatively low pressures acting over large surface areas. **The surface area over which pressure is acting should always be taken into consideration.**

Equally, the energy stored in a volume of pressurised gas far exceeds that of the same volume of liquid under the same pressure due to the difference in compressibility. This difference should be considered when assessing risks of particular situations.

Understanding equipment limitations shall be understood prior to working with any pressures. Serious consequences have resulted from equipment or systems being exposed to pressure levels in excess of designed operating limits. Awareness of the risks associated with over pressure and pressure transfer between specification breaks is critical when managing pressure and shall always be considered when operating any contained process systems.

Table of Contents

1. Scope

a. This GP specifics requirements that are necessary when 'Working with Pressure' in a variety of routine Drilling, Completion and Well Operation and Intervention operations.

b. The scope of this GP includes all wells, drilling rigs (fixed or mobile), well intervention, well service or well stimulation activity or service company rental tools or equipment in use at a BP location. Additionally this scope includes subsea activity in relation to well construction or completion operations.

c. This GP is specifically not intended to include activity involving working with pressure for other functional or operational groups such as process plant operation or maintenance.

d. The basic concept used during pressure testing is to use fluid and system compressibility effects to try and detect leakage from an enclosed system. This simple concept generally works reasonably well in most oil field situations where we can use a relatively low compressibility fluid like water to test the systems that we require assurance.

e. Whilst this simple technique normally works very well there are some effects that can complicate pressure testing and lead to greater uncertainty with the interpretation of the test observations. The most common issues are listed below:

1. Temperature effects.
2. Varied compressibility due to entrained gas
3. System elasticity causing expansion under pressure
4. Gauge and recorder performance
5. System volume being tested - potentially significant leaks will be more apparent on smaller system volumes than larger ones.

f. These issues shall be taken into consideration when developing pressure test durations and test acceptance criteria for critical service systems – e.g. tubular and equipment integrity tests.

2. Normative references

The following referenced documents may, to the extent specified in subsequent clauses and normative annexes, be required for full compliance with this GP:

- For dated references, only the edition cited applies.
- For undated references, the latest edition (including any amendments) applies.

BP

GP 10-01	Group Practice for Casing and Tubing Design
GP 10-10	Group Practice for Well Control
BPA-D-001	Drilling and Well Operations Practice DWOP
BPA-D-002	BP Well Control Manual

Industry Standards

Institute of Petroleum	Model Code of Safe Practice Part 17: Well Control During the Drilling and Testing of High Pressure Offshore Wells.

3. Terms and definitions

For the purposes of this GP, the following terms and definitions apply:

Annular BOP

Annular BOPs have a doughnut-shaped elastic element with bonded steel internal reinforcing. Extrusion of the element into the wellbore is effected by upwards movement of a hydraulically actuated piston. The element is designed to seal around any shape or size of pipe and to close on openhole.

Burst

Burst loads are those where the internal pressure exceeds the external pressure on the casing.

Casing

One of several pressure and load bearing tubulars used to construct a well.

Check valve

A valve that allows flow only in one direction

Completion fluid

Fluid that resides in the annular space between production tubing and the production casing

Collapse

Collapse refers to the situation where the external pressure is higher than the internal pressure, and the pipe can fail due to a combination of elastic instability and yielding.

Leak off test

A test that determines the pressure at which fluids of a known density can be injected into a formation thereby giving a measure of the formation strength

Packer

A component of the downhole completion string that forms a permanent barrier in the annular space between completion tubing and production casing.

Treating iron

Temporary pipework assembled for the purpose of transporting treatment fluid from treatment pump to the wellhead.

Tubing

The innermost tubular string that serves as a conduit for reservoir fluids and /or injection fluids

4. Symbols and abbreviations

For the purpose of this GP, the following symbols and abbreviations apply:

API	American Petroleum Institute
BOP	Blow Out Preventor
IP	Institute of Petroleum

MCOP	Model Code of Practice
MOC	Management of Change
MSDS	Material Safety Data Sheets
PRV	Pressure Relief Valve
PSI	Pounds per Square Inch
SCS	Service Company Supervisor
SOP	Site Operating Procedure
SPU	Strategic Performance Unit
WSL	Well Site leader

5. General pressure testing

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

b. 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 (defined as stable or decreasing pressure fall off less than 10 psi/min).

   A 5 minute test on a BOP or valve is sufficient to give assurance that there is integrity and that the unit under test is operating without any obvious major problems. Equipment verification pressure tests following manufacture or major servicing need stricter assurance requirements.

c. For well integrity testing of casing and tubing strings, where system volumes are typically large, a satisfactory pressure test should be carried out for a minimum undisturbed 30 minute monitoring period. An acceptable test would be defined as stable or decreasing pressure fall off less than 5 psi/min for the final 15 minutes.

   Tubing and casing integrity tests are the most difficult to get confidence with as system volumes are often large. Well Site Leaders should test these for longer and be more careful with the fall off trend analysis.

   For critical wells it may be necessary to increase the tubing integrity testing requirements.

d. All tests shall be recorded on a chart or an electronic data logger. The gauge and chart operating range shall be appropriate for the pressure being tested and accurately calibrated. Calibration shall be demonstrated by a documented Preventative Maintenance program.

e. Water should be the preferred medium for pressure testing. However, once reservoir fluids have been produced to surface, consideration should be made to the use of a water/glycol mixture as the test/flushing fluid to avoid hydrate problems. Low temperature pressure testing shall utilize low freeze-point fluids.

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

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

h. The possibility of a test pressure leaking past a pack-off or test plug and being applied to a weaker element (e.g. casing collapse, lower rated ring gasket etc) shall always be considered. All reasonable steps shall be taken to monitor for, and eliminate, such an event.

i. Prior to any pressure testing, the area shall be isolated. Personnel shall be notified and/or evacuated.

6. Pressure testing of well control equipment

a. All subsea BOPs including annular BOPs should be pressure tested on a test stump prior to deployment. The stump test will be to the maximum anticipated wellhead pressure plus an acceptable safety factor expected in the well.

b. All well control equipment, except annular BOPs, should 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.

c. In the event that the maximum anticipated wellhead pressure is uncertain, then the well control equipment shall be tested to the lowest of the criteria presented above.

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

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

f. This fourteen (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.

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

h. The opening and closing volumes of all BOP functions shall be monitored and recorded on subsea stacks.

i. An accumulator test should be carried out as part of each regular BOP test and in accordance with the Well Control ETP GP 10-10, API RP 53 and the BP Well Control Manual. The check of pre-charge pressure should be made at times when the system may safely be depressurized.

j. When testing wellhead components, due consideration should be given to internal yield and collapse rating of relevant casing and components.

k. In situations where a wireline riser and lubricator (wireline pressure control equipment) are used they should be pressure tested as a minimum to the maximum anticipated wellhead pressure plus an acceptable safety factor, before exposing the equipment to well conditions.

7. Pressure testing of tubulars

a. This section applies to all casing, testing and completion strings that may be used in a well.

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

c. Pressure tests should not give rise to loads exceeding the following:

   1. 90% of API internal yield pressure
   2. Triaxial stress of 80% of nominal yield
   3. Connection pressure rating
   4. 70% of connection tensile rating

d. Due consideration should be given to the following:

   1. The density of fluid columns inside and outside the casing
   2. The burst rating for the weakest casing in the string
   3. The minimum design factors assumed for the casing
   4. The effect of pressure testing on casing tensile loads
   5. • Casing wear if drilling has taken place before testing

e. If a pressure test is carried out during cementing when bumping the plug, the external load should be assumed to be equal to the mud weight used to set the casing. Due consideration should be given to plug and float equipment pressure rating.

f. If a pressure test is carried out after waiting on cement, the external load should be as defined in the Casing Design Manual Part 3 Section 6 Paragraph 4.

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

h. 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.

i. For development wells the minimum pressure test for production casing and liners should be equivalent to the shut-in tubing pressure on top of the annulus completion fluids. Any additional loads that are to be placed on the casing string (e.g. operating annulus pressure controlled tools) shall also be taken into account when planning pressure tests. If the completion fluid weight is lighter than that during the pressure test then surface pressure related to pressure controlled tools can be reduced to give an equivalent burst pressure at total depth. Unless ample data is available to support an alternative, dry methane should be assumed in the calculation of surface pressure. For exploration wells the basic initial requirement is the same.

j. Production or test tubing shall be tested to the maximum anticipated surface pressure or maximum anticipated differential pressure, which ever is greater, plus an acceptable safety factor for all planned operating conditions. As a minimum, the pressure test for the production tubing shall give an internal pressure at the lower section of tubing or packer assembly equivalent to the pressure load from the shut-in tubing head pressure and produced fluid.

k. Pressure testing of tubing is dependent of the completion design and should be considered as part of the running procedure. Consideration shall be given to injection pressures and connection ratings.

   Completion or string running procedures should be designed to allow all tubing and completion connections to be pressure tested to their maximum anticipated operating or reasonably expected fault conditions.

l. 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. Where a drilling or completion operation is to be conducted that will impose a drawdown on the liner lap or previous casing shoe, a differential test shall be conducted which imposes a drawdown equivalent to or greater than that expected.

8. High pressure pumping

8.1. General

This section is intended to cover pumping operations where in excess of 50bbls of corrosive, erosive, or energised fluids are pumped by cement or specialist treating pumps, often through temporary pipe work installed for the task. It is not intended to cover routine pumping of drilling fluids through integral rig pumping and circulating systems.

8.2. Planning

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

b. Each SPU shall develop and maintain a standard and a control process in place to manage the transportation, storage and use of hazardous materials to be used during pumping operations. Personnel, who may be exposed to hazardous materials, including liquid nitrogen and carbon dioxide, 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.

c. A pre-job risk assessment shall be performed before rigging up any high pressure pumping equipment at ambient temperature less than -20oF due to temperature effects on carbon steel or greater than 100oF due to personnel health risks. The effects of these extremes of temperature on personnel, equipment, fluids, and additives shall be considered.

8.3. Pumping operations

a. All personnel, including non-essential personnel, shall be assigned a position or work area prior to the pumping operation. Once the pumping operation has begun, all personnel shall stay in their assigned position, work area, or safe area unless required to egress for safety.

b. Safe areas shall be established prior to pumping operations. Safe areas shall be clear of obstructions and have easy access from all paths of emergency egress, and should be located upwind from the wellhead. All personnel shall be made aware of the safe area for each job during the pre-job risk assessment.

c. During all pumping and pressure testing operations, all personnel should either be:

   1. Shielded by heavy equipment or structures and out of the line of sight of the wellhead, treating line, and pump discharge, or

   2. Positioned at least 75 feet (25 meters) from the wellhead, treating line, and pump discharge.

Due to the limited foot print available for rigging up on offshore facilities; either the physical confines of the structure or the design of the mobile pumping equipment (i.e. coil tubing unit controls proximity to the coil) the requirement for 75 feet clearance between personnel and pressure may not be achievable. In these scenarios. mitigation of risk will be minimized through the operational sites safety management system.

d. Each well site shall develop equipment-specific tag-out procedures for safety critical wellhead valves, chokes and bleed line valves, which if operated in the wrong position (open or closed) during the pumping job, could result in an overpressure or other hazardous event. Such valves and chokes shall be tagged in the correct position for the duration of pressure testing and the pumping operation. The tag shall provide a highly visible and clear indication that the specific valve position shall be maintained.

e. A single trained person designated by the SCS and BP WSL, shall be authorized to install or remove tag-out indicators and to operate safety critical valves and chokes once pressure testing or pumping has begun.

f. 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.

g. All treating iron / temporary pipe work should 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. Any iron missing a tag should be removed from service before pumping operations commence.

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

i. 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.

j. The maximum allowable annulus pressure shall not exceed limits imposed by collapse ratings of the work or completion string, tubing movement calculations, and casing/tubing design criteria.

k. The annulus should be pressure tested prior to the pumping operation to the maximum allowable annulus pressure. Verification of previous pressure tests shall be available to the BP WSL on location at the time of the operation.

l. Annular casing strings isolated from frac pressure with a packer should be equipped with a pressure relief mechanism.

   1. Maximum set pressure of spring loaded "pop-off" valves should not exceed 75% of the maximum allowable annular pressure.

   2. Maximum set pressure of nitrogen or hydraulic actuated pressure relief valves shall not exceed 95% of the maximum allowable annular pressure.

3. The pressure relief valve should be function tested prior to the pumping operation.

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

n. Where the treating line incorporates a check valve, the check valve should be tested following the pressure test. To ensure the check valve is holding, bleed the pressure off the treating line on the pump side of the check valve. If pressure doesn't hold, the check valve is leaking and should be repaired or replaced prior to pumping and re-tested.

o. Pump trips / kick-outs are required on each pump. These trips will automatically kick the pump into neutral, and/or shut down the pump engine when its set point pressure is reached. Maximum set pressure should not exceed 95% of the maximum allowable treating pressure. Each trip should be function tested at its set pressure on every job, per service company procedures. If a pump trip fails to function properly at the set pressure, the problem should be corrected before that pump is used in the treatment.

p. An emergency pressure trip or shutdown system should be used, which actuates when the pressure measured by the wellhead transducer exceeds the set point. This system should automatically kick all pumps into neutral and/or shut down the pump engines. Maximum set pressure shall not exceed 95% of the maximum allowable treating pressure. The system should be function tested at its set pressure prior to job commencement.

q. A manual emergency kill switch should be easily accessible that kicks all pumps into neutral and/or shuts down the pump engines when actuated. The kill switch should be function tested prior to job commencement.

r. Pressure Relief Valves (PRVs) may be used on non-energized treating lines, but are not required. If a PRV is used on a non-energized treating line, it should be isolated from the main treating line by a remotely operated valve, which should be tagged open during the operation. Additionally PRV should be anchored with restraints. PRVs should not be used on any energized treating lines.

s. Protective systems required on pumping operations should be fully functional and not disabled.

9. Remedial pressure operations

9.1. General

Cleaning of rig equipment and tanks using high pressure jet washing equipment is a routine activity that can occur at any stage of Drilling Completion or Well Operations using a variety of systems. This operation can be extremely hazardous (including the risk of fatality) if

a. Jet washing equipment lacks integrity, through inadequate design or maintenance.

b. Correct procedures are not followed.

c. People are not competent to operate the equipment or are poorly supervised.

9.2. Equipment

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

b. All tank cleaning operations shall be undertaken with equipment that can only be operated at or below pressures stated in the risk assessment for this activity. In situations where the pump can exceed that pressure, a system to provide relief at pressures below the stated risk assessment pressure shall be utilized. If conditions change, the job should be stopped and risks re-assessed.

c. If pressures greater than 100psi can be achieved, a system that has been designed, purpose built, and reviewed by engineering authorities should be utilized. The pumping system should have mechanical shut down devices to prevent pressure in excess of the pressure stated in the risk assessment.

d. Pump components (impellers), which are exposed to fluids being pumped during the life of the pump, shall be compatible with commonly utilized fluids (water, diesel, fluid spacers, etc.).

e. Contractors that provide pressure pumping equipment should be expected to conduct regular maintenance checks on pumping equipment to confirm that all flow wetted components (pumps, hoses, gauges and valves) are in operational condition. The contractor should maintain records pertaining to replacement and repair and a job log describing use in previous locations.

10. Compressed gas handling

a. Nitrogen / CO_2 - cryogenic gasses have the capacity to inflict serious frost bite and / or asphyxiation. Correct PPE shall be worn when handling cryogenic gasses.

b. If insufficient oxygen is present, high concentrations can cause asphyxiation and death. There are no physiological warning signs to nitrogen enrichment. Personnel should be aware of this risk when working with Nitrogen in enclosed spaces.

c. Leaks of cryogenic liquids onto unprotected steel decks or other structural members can result in brittle fracturing. Mitigating actions should be taken to prevent this potential.

11. Pulsation dampeners and accumulators

a. 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.

b. When working to check the N_2 pre-charge, or replace the pre-charge element on pulsation dampeners or accumulators the following shall be observed:

   1. People undertaking the job shall be competent to do so.
   2. The correct operating pressure rating for the equipment shall be known by the person carrying out the task and verified by a supervisor.
   3. The SOP for the task shall be followed, using the correct equipment, adequate isolations in place and authorized permit to work.

12. Risk assessment

a. A risk assessment shall include detailed mitigation steps for pumping risks. (I.e. hose movement, over-pressurization of system due to plugging, pressure limitation devices etc.) and discussion of potential issues that could result in sudden pressure increases anywhere in the pressured system (debris, air etc.).

b. In situations where personnel are still required to operate a hose to clean tanks, a risk assessment of all components should be conducted. Focus areas should include pressure limitations and relief, hose, operator control options, and nozzle design.

c. Risk assessments shall be conducted on each and every well treatment activity where diesel, hazardous materials or chemicals are involved. Current Material Safety Data Sheets (MSDS) of all chemicals and treatment fluids on location, or equivalent, shall be available at the well site.

d. A pre-job risk assessment should be conducted at the start of each shift and whenever there is a change in operational activities. Documentation of these assessments should be maintained by the responsible contractor and reviewed by the BP WSL at the rig site for the duration of the well operations and made part of the complete well file.

13. Process and procedure

a. Changes in work scope or work conditions are to be communicated to well site leadership and all parties engaged in such work.

b. Decisions by leadership regarding replacement of pumping equipment should be made through the use of MOC discussions. If the MOC is agreed, a thorough discussion of potential risks and mitigation steps will be present in a new risk assessment.

c. A detailed operational procedure shall be utilized to conduct any operation designated as "Working with Pressure". This procedure shall detail steps to be taken in working with pressure operations. This procedure shall include details about equipment capabilities, pressure relief settings and contingencies for the operation. It shall also describe risks for the operation and steps to mitigate those risks. This procedure shall be consistent with the risk assessment for this operation.

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

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

14. People competence

Contractor personnel that are onsite to operate pumping equipment shall be expected to have significant experience in operating the equipment on location. The WSL shall verify operator's specific experience with the equipment.

15. High pressure/high temperature well control

All HP/HT Well Control operations shall be conducted in accordance with IP MCOP Part 17 - Well Control during the Drilling and Testing of High Pressure Offshore Wells.