

# **SERVICE RIG OPERATION SAFETY GUIDELINES AND INTERPRETATION NOTES (DRAFT)**

**Office of the Regulator of Oil and Gas Operations  
September 12, 2024**

# **BULLETIN D'APPLICATION ET DIRECTIVES SUR LA SÉCURITÉ DE L'EXPLOITATION DES PLATEFORMES DE MAINTENANCE (VERSION PROVISOIRE)**

**Bureau de l'organisme régulateur des opérations  
pétrolières et gazières**

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*Le présent document contient la traduction française du sommaire*



NWT OFFICE OF THE REGULATOR OF OIL AND GAS OPERATIONS



BUREAU DE L'ORGANISME DE RÉGLEMENTATION DES OPÉRATIONS PÉTROLIÈRES ET GAZIÈRES DES TN-C



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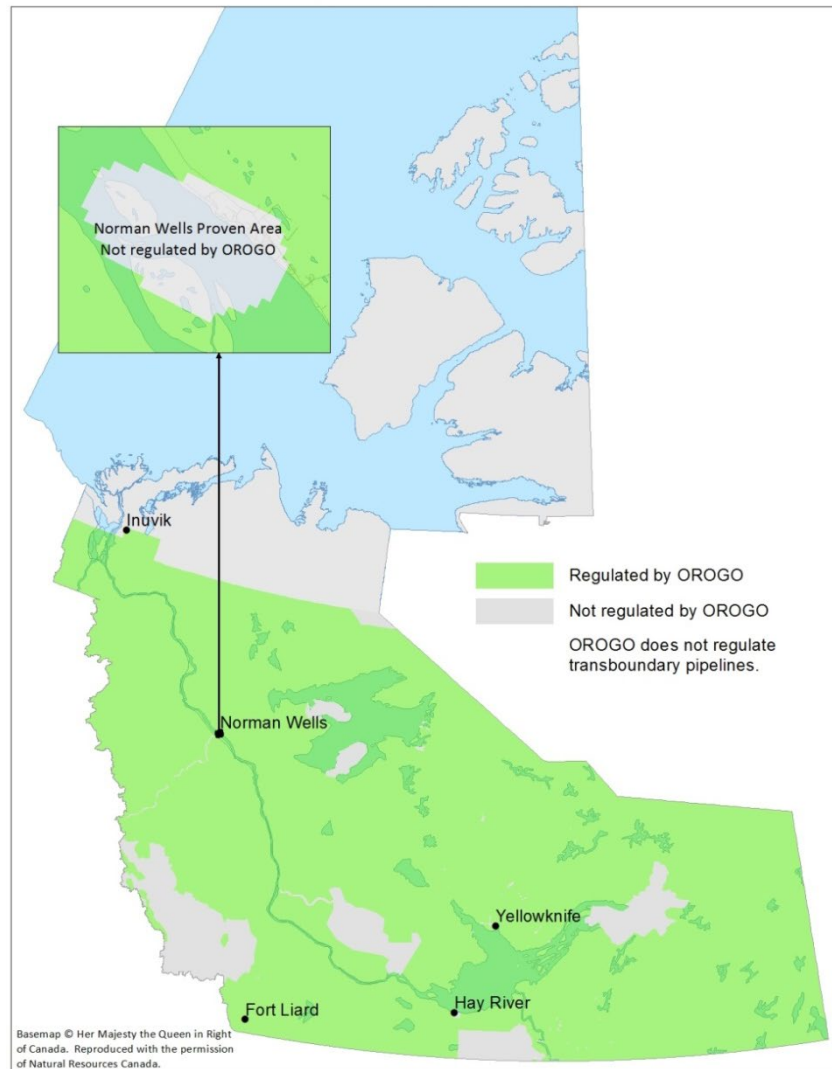
# 1 Introduction

<b>Purpose</b>	The <i>Service Rig Operation Safety Guidelines and Interpretation Notes</i> (Guidelines) provide guidance for operators on in-field requirements for service rigs and associated equipment.
<b>Objectives</b>	The objectives of these Guidelines are to: <ul style="list-style-type: none"><li>• Support compliance with the <i>Oil and Gas Operations Act</i> (OGOA) and its regulations.</li><li>• Reflect the context of oil and gas activities in the Regulator’s jurisdiction.</li><li>• Be consistent with the requirements of other western Canadian regulators, in particular the Alberta Energy Regulator’s <i>Directive 037: Service Rig Inspection Manual</i>.</li></ul>
<b>Legislative requirements</b>	The <i>Oil and Gas Drilling and Production Regulations</i> require operators to ensure that: <ul style="list-style-type: none"><li>• Reliably operating well control equipment is installed to control kicks, prevent blow-outs, and safely carry out all well activities and operations (section 36(1)).</li><li>• Pressure control equipment is pressure-tested on installation and as often as necessary to ensure its continued safe operation (section 37).</li></ul>
<b>Minimum requirements</b>	The Guidelines set out the minimum requirements for operators. Operators may suggest alternative approaches that are demonstrated to meet or exceed the same standards for the protection of human safety and the environment.
<b>Regulator’s discretion</b>	Application of these Guidelines is subject to the Regulator’s discretion under OGOA.
<b>Authority</b>	These Guidelines are issued by the Regulator under section 18 of the <i>Oil and Gas Operations Act</i> (OGOA).

## Service Rig Operation Safety Guidelines and Interpretation Notes (Draft)

### Jurisdiction

These Guidelines apply in the Regulator's jurisdiction, as shown on the following map.



### Application

These Guidelines apply to all operations conducted with a service rig except operations on:

- Critical sour wells.
- Acid gas Wells
- Wells without a surface casing.

## Service Rig Operation Safety Guidelines and Interpretation Notes (Draft)

**Definition: critical sour well** A well is considered **critical sour** based on its location and known H<sub>2</sub>S release rate upon completion, as shown in the following table.

A critical sour well is located	and has a known H <sub>2</sub> S release rate upon completion of
Within 500 meters of the boundaries of a population centre	0.01 to 0.09 cubic meters per second (m <sup>3</sup> /s)
Within 1.5 kilometers of the boundaries of a population centre	0.1 and 0.29 m <sup>3</sup> /s
Within 5 kilometers of the boundaries of a population centre	0.3 and 1.99 m <sup>3</sup> /s
Anywhere in the Regulator’s jurisdiction	2.0 m <sup>3</sup> /s or more.

**Definition: population centre** A **population centre** is any incorporated, unincorporated, or self-governing community in the Regulator’s jurisdiction, any seasonal camp or similar area, or as otherwise determined by the Regulator.

A list of Northwest Territories communities is available on the website of the [Department of Municipal and Community Affairs](#).

**Definition: acid gas well** An **acid gas well** is a well that produces a combination of any amount of H<sub>2</sub>S and CO<sub>2</sub> or into which a combination of any amount of H<sub>2</sub>S and CO<sub>2</sub> is injected.

**Plain language** These Guidelines have been written in plain language to make them accessible to as many readers as possible.

**Regulations are paramount** Where a conflict exists between the Guidelines and the *Oil and Gas Operations Act* (OGOA) or its regulations, OGOA and the regulations are paramount.

## 2 Sommaire

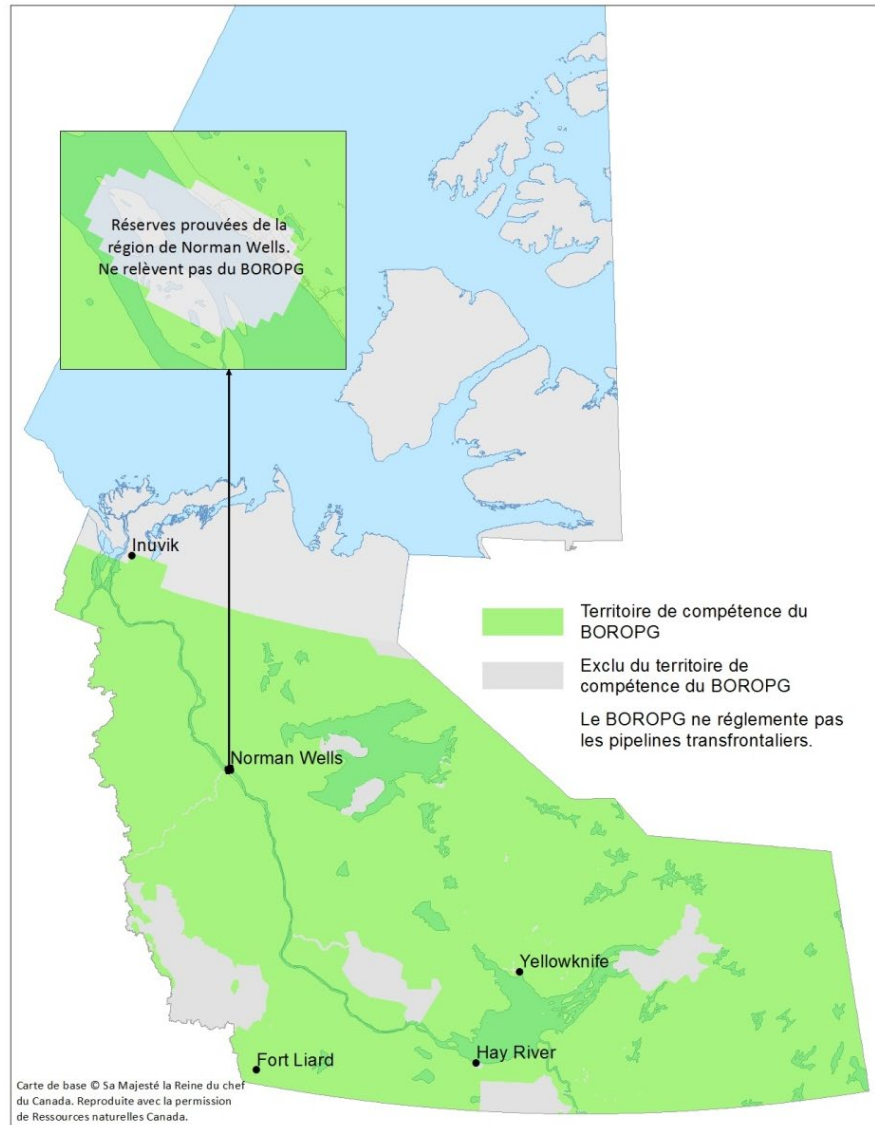
<b>But</b>	Le <i>Bulletin d'application et directives sur la sécurité de l'exploitation des plateformes de maintenance</i> (Directives) décrit les exigences sur le terrain pour les exploitants de plateformes de maintenance et de l'équipement connexe.
<b>Objectifs</b>	Objectifs des Directives : <ul style="list-style-type: none"><li>• Appuyer la conformité à la <i>Loi sur les opérations pétrolières</i> (LOP) et ses règlements.</li><li>• Prendre en compte le contexte dans lequel se déroulent les activités pétrolières et gazières sur le territoire de compétence relevant de l'organisme de réglementation.</li><li>• Assurer la cohérence avec les exigences des autres organismes de réglementation de l'Ouest canadien, en particulier la directive 037 de l'Alberta Energy Regulator, Manuel d'inspection des plateformes de service.</li></ul>
<b>Exigences prévues par la loi</b>	Le <i>Règlement sur le forage et la production de pétrole et de gaz</i> exige des exploitants : <ul style="list-style-type: none"><li>• que l'équipement fiable de contrôle du puits soit en place pour contrôler les venues, prévenir les éruptions et exécuter en toute sécurité les activités et les travaux relatifs au puits [paragraphe 36(1)];</li><li>• que l'équipement de contrôle de pression soit soumis à une épreuve sous pression au moment de son installation, et par la suite, aussi souvent que cela est nécessaire pour en garantir la sécurité de fonctionnement [paragraphe 37].</li></ul>
<b>Pouvoir discrétionnaire de l'organisme de réglementation</b>	La LOP accorde à l'organisme de réglementation un pouvoir discrétionnaire dans l'application des présentes Directives.
<b>Autorité</b>	L'organisme de réglementation publie les présentes Directives en vertu de l'article 18 de la <i>Loi sur les opérations pétrolières</i> (LOP).



## Service Rig Operation Safety Guidelines and Interpretation Notes (Draft)

### Compétence

Ces Directives s'applique au territoire de compétence relevant de l'organisme de réglementation, tel qu'indiqué sur la carte ci-dessous.



### Prédominance du Règlement

En cas de conflit, la LOP ou ses règlements l'emportent sur les présentes Directives.

### 3 CAOEC Compliance

#### Requirements

Operators must maintain compliance with the current editions of the following [Recommended Practices](#) issued by the Canadian Association of Energy Contractors (CAOEC):

- Recommended Practice 3.0: Inspection and Certification of Masts
- Recommended Practice 4.0: Inspection and Certification of Overhead Equipment
- Recommended Practice 6.0: Inspection and Certification of Blowout Preventers
- Recommended Practice 10.0: Inspection of Drawworks Brake Load Path Components
- Recommended Practice 11.0: Inspection and Certification of Carrier Mounted Equipment

**Exception:** If there is a conflict between the listed Recommended Practices and these Guidelines, the Guidelines apply.

## 4 Well Control Equipment

### Contents

This section contains requirements that apply to all well control equipment:

- Minimum specifications
- Equipment testing
- Cold weather operations
- Sour gas operations
- Alert device

It also contains requirements for specific well control equipment:

- Blow out prevention system
- Bleed-off system / kill system

## 4.1 Minimum specifications

**Contents** This section contains the minimum specifications for the three classes of servicing blowout prevention (BOP) systems:

- Class I systems
- Class II systems
- Class III systems

**Class I systems** Class I servicing BOP systems are used for wells with:

- Reservoir pressure < 5,500 kPa and
- No H<sub>2</sub>S.

Class I servicing BOP systems have the following characteristics:

- The well is not killed.
- A pipe and blind ram blowout preventer unit may be used instead of an annular preventer (the position of the ram may be interchanged).

**Class II systems** Class II servicing BOP systems are used for wells with:

- A production casing flange rated to  $\leq 21,000$  kPa and
- H<sub>2</sub>S < 10 moles/kilomole.

Class II servicing BOP systems have the following characteristics:

- The pressure rating of the preventers is equal to or greater than the production casing flange rating, or the formation pressure, whichever is less.
- The positioning of the pipe and blind rams may be interchanged.
- The spool may have threaded side outlet (and valve) if the wellhead has threaded fittings.
- A flanged blowout preventer port (and valve) below the lowest set of rams may replace the spool (the valve may be threaded if wellhead has threaded fittings).
- All lines are 50 mm in diameter.

**Class III systems** Class III servicing BOP systems are used for wells with:

- A production casing flange rated to > 21,000 kPa or
- A production casing flange rated to  $\leq 21,000$  kPa and H<sub>2</sub>S > 10 moles/kilomole.

Class III servicing BOP systems have same characteristics as Class II wells.

**Connectors** Acceptable types of connectors are based on the production casing flange rating or the formation pressure, whichever is less. Connectors must meet manufacturer specifications.

## **Service Rig Operation Safety Guidelines and Interpretation Notes (Draft)**

Clamp type connectors that serve the same function as a high-pressure flanged assembly may be used in the BOP system to replace a flanged connection.

All flange or clamp type connectors must be pressure tested at the connection whenever a connection is loosened or disassembled.

All connectors must meet the standards of the API (American Petroleum Institute) or the American National Standards Institute (ANSI). Non-API or -ANSI connectors must be certified by the original equipment manufacturer or a professional engineer. Documentation must be provided as required by the well approval.

## 4.2 Equipment testing

**Contents** This section contains requirements for testing well control equipment, including:

- Required tests and frequency
- Recording results
- Pressure test procedures
- Expected pressure test results
- BOP three function test procedures
- Expected three function test results

**Required tests and frequency** The required tests and their frequency are summarized in the following table:

Test	Frequency
Pressure test	Before start of operations.
BOP three function test	Before start of operations. Minimum every 7 days after initial test during the same operation.
BOP component test	Daily: annulars and pipe rams. Daily: blind rams (when the string is out of the hole). Minimum before start of operations and every 7 days: valves.

**Recording results** Test results are recorded on the tour sheet and in the daily reports.  
BOP function test results must include a list of the components tested.

**Pressure test procedures** The procedures for a pressure test are:

1. Pressure test the connection between the stack and the wellhead, the stabbing valve, the bleed-off manifold, and the bleed-off/kill lines by:
  - a) Conducting a low-pressure test to 1,400 kPa on each ram preventer.
  - b) Conducting a high-pressure test on each ram preventer, the full opening safety valve, and the connection between the stack and the wellhead. Test to the wellhead pressure rating or the formation pressure, whichever is less.
  - c) Testing the annular preventer to 7,000 kPa or the formation pressure, whichever is less.
  - d) Testing all valves in the bleed-off/kill line individually to the same pressure as the manifold, to the wellhead pressure rating, or to the formation pressure, whichever is less.

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2. Pressure test the BOP to wellhead connection to the wellhead pressure rating or to the formation pressure, whichever is less. The procedure is based on what is present in the wellbore, as follows:

*If no tubing is in the well, and a formation is open to the wellbore:*

- a) A packer may have to be run in the casing to permit pressure testing.
- b) The tubing hanger may be run on the bottom of a joint of tubing and landed in the tubing spool (set screws secured).
- c) Testing can then take place by pressuring up below a closed preventer.

*If tubing is in the well and the formation is open to pressure:*

- a) A pup joint can be screwed into the tubing hanger and testing can take place by pressuring up below a closed preventer.
- b) The pup joint must be blanked on the bottom and perforated above the blank if pressure testing the stabbing valve along with the BOP.

*If using a slip type wellhead:*

- a) A tubing hanger designed for use with a slip type wellhead may be landed in the tubing spool after the slips, seals, and tubing head adapter have been removed.
- b) A pup joint can be screwed into the tubing hanger and testing can take place by pressuring up below a closed preventer.
- c) The pup joint must be blanked on the bottom and perforated above the blank if pressure testing the stabbing valve along with the BOP.

### Expected pressure test results

All tests are expected to demonstrate that well control equipment complies with these Guidelines.

For pressure tests, all components must maintain a stabilized pressure of at least 90% of the test pressure over a 10-minute interval.

**Loss of Pressure:** If there is a loss of pressure during the test, determine whether the issue is with the tubing hanger or the BOP, as follows:

1. Maintain the required pressure on the wellhead while the pipe rams (or annular) and the wellhead connection are monitored for leaks.
2. If there are no leaks within the BOP connections, the test is satisfactory but the operator must replace the faulty tubing hanger.

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**Exception:** If an electrical submersible pump is in use, a pressure test of the wellhead connection cannot be conducted. This is acceptable.

**Prohibition:** Well control equipment that does not comply with these Guidelines must be taken out of service immediately and repaired or replaced.

### BOP three function test procedures

The procedure for a BOP three function test is:

1. Bleed the system down to recharge pressure setting.
2. Turn off the accumulator pump.
3. Function the pipe ram (closed) and record the closing time.
4. If there is no work string or wireline down hole, function the blind ram (closed) and record the closing time; or  
If there is a work string or wireline down hole, function the pipe ram (open) and record the opening time and final stabilized pressure.
5. Function the annular (closed) and record the closing time and final stabilized pressure.
6. Turn on the accumulator pump and record recharge time and stabilized pressure.

### Expected three function test results

All tests are expected to demonstrate that well control equipment complies with these Guidelines.

For BOP three function tests, the final stabilized pressure cannot drop below 8400 kPa and the accumulator must recharge to operating pressure within 5 minutes of turning on the accumulator pump.

**Prohibition:** Well control equipment that does not comply with these Guidelines must be taken out of service immediately and repaired or replaced.



## 4.3 Cold weather operations

### Requirements

If the temperature is below 0°C, not including wind chill:

- The BOP stack, all associated valves, the circulation manifold, and the accumulator system must be heated to maintain effectiveness.
- The bleed-off, kill, diverter, and flare lines must be:
  - Void of fluid traps;
  - Blown out with air; and
  - Filled with a non-freezing fluid capable of being mixed with water without separating or heated.
- A boiler with a remote steam nozzle must be available and able to reach the entire work site.
- The stabbing valve must be kept ice free.

## 4.4 Sour gas operations

**Requirements** During operations on sour gas wells, all pressure-containing components within the BOP, bleed-off, and kill systems must meet the requirements of the current ANSI/National Association of Corrosion Engineers (NACE) [MR0175: Petroleum and Natural Gas Industry – Materials for Use in H<sub>2</sub>S-Containing Environments in Oil and Gas Production.](#)

## **4.5 Alert device**

**Mandatory crew alert device** An operable alert device must be installed for alerting the crew in the event of a well control situation or BOP drill.

## 4.6 Blow out prevention system

<b>Contents</b>	<p>This section contains requirements for BOP systems used in service rig operations, including:</p> <ul style="list-style-type: none"><li>• The BOP stack</li><li>• The accumulator system</li><li>• The backup nitrogen system</li><li>• The BOP controls</li></ul>
<b>General BOP system requirements</b>	<p>BOP equipment must be installed and maintained on all wells. It must be:</p> <ul style="list-style-type: none"><li>• Able to shut off a flow at the wellhead, even if any type of tool or equipment is being used in the well.</li><li>• Compliant with the specifications in these Guidelines.</li></ul> <p>If redundant BOP equipment used, it must be:</p> <ul style="list-style-type: none"><li>• Always functional (unless the hydraulic lines are disconnected).</li><li>• Included in all pressure testing.</li><li>• Included in accumulator and backup nitrogen system volume calculations.</li><li>• Locked out when not in service (control handles removed or lines disconnected).</li></ul>

### 4.6.1 BOP stack

<b>Contents</b>	<p>This section contains requirements for BOP stacks used in service rig operations, including:</p> <ul style="list-style-type: none"><li>• Double drilling or studding</li><li>• Casing bowls</li><li>• Stabbing valves</li></ul>
<b>Double drilling or studding</b>	<p>BOP equipment may be double drilled or studded. However:</p> <ul style="list-style-type: none"><li>• Double studding the BOP body to accept two sizes of API flanges (for equipment that may have a lower pressure rating) does not result in the derating of the BOP.</li><li>• Double drilling or studding flanged BOP equipment to accommodate connections to other API equipment with a lower pressure rating results in a derating of the flange to the lower working pressure. If the modified flange is to be used in an application requiring its original pressure rating, the operator must provide documentation from the original equipment manufacturer or a professional engineer that the flange is certified for the higher pressure rating as required by the well approval.</li></ul>

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<b>Casing bowls</b>	Casing bowls must have: <ul style="list-style-type: none"><li>• A casing flange that is an integral part of the bowl.</li><li>• At least one threaded, flanged, or studded side outlet and valve.</li></ul>
<b>Stabbing valves</b>	All service rigs must be equipped with a stabbing valve rated for maximum operating pressure. Stabbing valves must be: <ul style="list-style-type: none"><li>• Fully opening and equipped with a valve operating wrench.</li><li>• Stored in the open position.</li><li>• Operable and readily accessible on the rig floor.</li><li>• Equipped with removable handles if more than one person is required to carry the valve. A full open hanger cap assembly may be used in place of handles.</li></ul>

### 4.6.2 Accumulator system

<b>Contents</b>	This section contains requirements for accumulator systems, including: <ul style="list-style-type: none"><li>• Hydraulic fluid capacity</li><li>• Sizing calculations</li><li>• Recharge capacity</li><li>• Speed</li><li>• Venting (for class III wells)</li><li>• Installation</li></ul>
<b>Hydraulic fluid capacity</b>	The accumulator system must be able to provide, without recharging, hydraulic fluid of sufficient volume and pressure to close the annular preventer on the pipe, close one ram preventer, and retain a minimum pressure of 8,400 kPa on the accumulator system.
<b>Sizing calculations</b>	Accumulator sizing calculations must be completed as described in the <a href="#">Energy Safety Canada</a> Well Service Blowout Prevention course. Calculations must be completed before operations begin to ensure appropriate equipment is in use.
<b>Recharge capacity</b>	The accumulator system must include an automatic pressure-controlled recharge pump that recovers, within 5 minutes, the pressure drop resulting from the function test of the BOP components.
<b>Speed</b>	The accumulator system must be able to: <ul style="list-style-type: none"><li>• Close any ram-type BOP within 30 seconds.</li><li>• Close any annular type BOP:<ul style="list-style-type: none"><li>○ Within 60 seconds (wellbore diameter <math>\leq</math> 350 mm).</li><li>○ Within 90 seconds (wellbore diameter <math>&gt;</math> 350 mm).</li></ul></li></ul>

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<b>Venting (for class III wells)</b>	For class III wells, the accumulator system must be designed so the vent on the accumulator reservoir vents outside the building, through the side or top of building.
<b>Installation</b>	The accumulator system must be: <ul style="list-style-type: none"><li>• Readily accessible.</li><li>• Connected to the BOP stack with hydraulic BOP lines (steel or non-steel) of working pressure equal to or greater than the manufacturer's design pressure of the accumulator.</li><li>• Equipped with:<ul style="list-style-type: none"><li>○ A check valve located between the accumulator charge pumps and the accumulator bottles.</li><li>○ An accurate gauge to determine accumulator system pressure.</li><li>○ Readily accessible fittings and gauges to determine the pre-charge pressure of the accumulator bottles.</li></ul></li><li>• Housed to ensure the system can be protected from the well in the event of an uncontrolled flow.</li><li>• Connected to a backup nitrogen system (see section 4.6.3).</li></ul>

### 4.6.3 Backup nitrogen system

<b>Contents</b>	This section contains requirements for backup nitrogen (N <sub>2</sub> ) systems, including: <ul style="list-style-type: none"><li>• N<sub>2</sub> capacity</li><li>• Sizing calculations</li><li>• Installation</li></ul>
<b>N<sub>2</sub> capacity</b>	The backup N <sub>2</sub> system must be capable of providing sufficient volume and pressure to close the annular preventer on the pipe, close one ram preventers, and retain a minimum pressure of 8,400 kPa on the N <sub>2</sub> backup system.
<b>Sizing calculations</b>	N <sub>2</sub> backup sizing calculations must be completed as described in the <a href="#">Energy Safety Canada</a> Well Service Blowout Prevention course. Calculations must be completed before operations begin to ensure appropriate equipment is in use.
<b>Installation</b>	The backup N <sub>2</sub> system must be: <ul style="list-style-type: none"><li>• Readily accessible.</li><li>• Connected to operate the BOPs and not allow the N<sub>2</sub> to discharge into the accumulator reservoir or the accumulator bottles (including use of isolation valves).</li><li>• Equipped with a gauge to determine the backup N<sub>2</sub> pressure or have a gauge readily available for installation.</li></ul>

## Service Rig Operation Safety Guidelines and Interpretation Notes (Draft)

- Housed to ensure the system can be protected from the well in the event of an uncontrolled flow.
- Adequately heated to maintain effectiveness.

### 4.6.4 BOP controls

<b>Contents</b>	This section contains information on the requirements for BOP controls, including: <ul style="list-style-type: none"><li>• Primary controls</li><li>• Secondary controls</li><li>• Master hydraulic control manifold</li></ul>
<b>Primary controls</b>	Each BOP component must have a separate control located at the remote position (typically the accumulator). These controls must be: <ul style="list-style-type: none"><li>• Capable of opening and closing each BOP component.</li><li>• Readily accessible and housed to ensure that they can be protected from the well in the event of an uncontrolled flow.</li><li>• Correctly identified and show function operations (open and close).</li><li>• Equipped with an accurate gauge indicating the accumulator system pressure.</li></ul>
<b>Secondary controls</b>	Each BOP component must have a separate control located near the driller's position on the rig floor. These controls must be: <ul style="list-style-type: none"><li>• Capable of opening and closing each BOP component.</li><li>• Readily accessible, correctly identified, and show function operations (open and close).</li><li>• Equipped with an accurate gauge indicating the accumulator system pressure.</li></ul>
<b>Master hydraulic control manifold</b>	The master hydraulic control manifold must be located at the remote position (typically the accumulator) for all wells.

## 4.7 Bleed-off / kill system

<b>Contents</b>	This section contains requirements for: <ul style="list-style-type: none"><li>• Circulation manifolds</li><li>• Rig tanks and fluid volume monitoring systems</li><li>• Tubing pressure gauge assemblies</li><li>• Bleed-off / kill lines</li><li>• Pressure tanks</li><li>• Flare lines</li></ul>
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### 4.7.1 Circulation manifolds

<b>Contents</b>	This section contains the requirements for circulation manifolds: <ul style="list-style-type: none"><li>• Components</li><li>• Installation</li><li>• Pressure gauges</li></ul>
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<b>Components</b>	A circulation manifold consists of high-pressure pipes, fittings, flanges, valves, pressure gauges, and manually operated adjustable valves.
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<b>Installation</b>	The circulation manifold must: <ul style="list-style-type: none"><li>• Be outside the substructure and readily accessible.</li><li>• Be labelled to identify the fully open and fully closed positions for all valves.</li><li>• Always be fully operable with all valve handles in place.</li></ul>
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The circulation manifold may include in-line glycol recovery drainage ports if they do not compromise system integrity or function.

**Prohibition:** No valves or other mechanical restrictions are permitted in the pressure vessel inlet line.

<b>Pressure gauges</b>	An accurate circulation manifold pressure gauge must be installed, or readily accessible for installation, at: <ul style="list-style-type: none"><li>• The circulation manifold, regardless of which valve line is in use; and</li><li>• The remote valve control location (if in use or required).</li></ul>
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All gauges must:

- Meet the pressure rating of the required BOP system.
- Have maximum readable increments of 500 kPa.
- Have isolation valves.



## 4.7.2 Rig tanks and fluid volume monitoring systems

**Requirements** All wells being serviced must have rig tanks with an appropriate rig tank fluid volume monitoring system.

If the rig tank is in use, the fluid volume monitoring system must be in service.

The fluid volume monitoring system must be able to measure an imbalance in the volume of fluids entering and returning from the well.

## 4.7.3 Tubing pressure gauge assemblies

**Requirements** Tubing pressure gauge assemblies must:

- Have an accurate pressure gauge and other necessary equipment installed or readily accessible.
- Be assembled by the rig crew as part of the BOP drill if the equipment is not already installed.
- Be readable from the rig pump control station while operating the valve from the circulation manifold.
- Have isolation valves.

## 4.7.4 Bleed-off/kill lines

**Contents** This section contains the requirements for the bleed-off/kill lines connecting the BOP stack to the circulation manifold:

- Valves
- Installation
- Flexible hoses
- Operation
- Wells with a total vertical depth (TVD) > 3,600 meters

**Valves** Bleed-off/kill lines include both hydraulically operated and manual valves.

**Installation** Bleed-off/kill lines must:

- Always be connected to the working spool and circulation manifold.
- Have flange or clamp type connectors pressure tested at the connection whenever a connection is loosened or disassembled after initial pressure test(s).
- Always have the valve handles in place for all manual valves in the primary and secondary bleed-off/kill lines.
- Directly connect the innermost valve to the working spool or ported ram assembly. Crossover flanges between the working spool and the innermost manual valve are permitted.

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- Be properly supported to prevent stresses on connecting valves and fittings.
- Be secured at every connection point and at no more than 10-meter intervals.

Bleed-off/kill lines may include piping extensions or fluid turns between the manual valves if:

- The innermost valve is in the closed position and the secondary bleed-off line (with two manual valves) is in use.
- All fluid turns in the bleed-off line are made with right angle (90°) connections constructed of tees and crosses blocked on fluid turns.

**Prohibition:** Piping extensions or fluid turns are not permitted between the working spool and the innermost valve.

### Flexible hoses

Flexible hoses may only be used for directional changes in the bleed-off lines downstream of the manual valves. They must:

- Have factory installed connections.
- Maintain their original shape and not contain bends with a radius less than the manufacturer's specified minimum bending radius.
- Be supported and protected from mechanical damage.
- Be secured (if it is a non-flange hose).
- Have competent fire sheathing to withstand a minimum of 700°C for 5 minutes flame temperature at a maximum working pressure without failure, if used within 7 meters of a well.

### Operations

During normal operations:

- The valve on the primary bleed-off line must be closed and the secondary valve must be in the open position.
- If the secondary bleed-off line is required or in use, only one of the manual valves on the secondary bleed-off line can be in the closed position, provided that both are flanged together.

### TVD > 3,600 meters

For wells with a TVD > 3,600 meters, there must be a separate bleed-off line from each working spool connected to each separate manifold wing to provide complete redundancy from the BOP stack through to the manifold.

## 4.7.5 Pressure tanks

<b>Requirements</b>	Pressure tanks must: <ul style="list-style-type: none"><li>• Be built of steel to ensure fluid containment during prolonged exposure to extreme heat. Structural integrity of the pressure tank must be maintained.</li><li>• Include an impingement plate to resist erosion from high-velocity gas, liquids, and solids on the wall directly opposite all flare lines connected to the tank.</li><li>• Have a minimum capacity of 8 m<sup>3</sup>.</li><li>• Always have a minimum 50.8 mm liquid loading steel line connected to draw fluids from the tank. The connection point of the loading line must extend at least 9 meters from the pressure tank.</li></ul>
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## 4.7.6 Flare lines

<b>Contents</b>	This section contains the requirements for flare lines from the circulation manifold to the pressure tank:
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- Installation
- Flexible hoses
- Wells with a TVD > 3,600 meters

<b>Installation</b>	Flare lines must be: <ul style="list-style-type: none"><li>• Always connected to the manifold.</li><li>• Laid in a straight line from the manifold to the pressure tank. If required to accommodate equipment, flare lines may contain directional changes if they are made with right angle (90') connections constructed of tees and crosses blocked on fluid turns.</li><li>• Connected using flanges, threaded fittings, or hammer unions. If a pressure tank is in use, interconnecting cable mechanisms or sling straps must be used to secure the connections.</li><li>• Secured:<ul style="list-style-type: none"><li>○ At every connection point.</li><li>○ At no more than 10-meter intervals</li><li>○ With the end of the line secured as close as possible to the pressure tank.</li></ul></li><li>• Self-draining or incorporating a means to drain fluid from the line.</li></ul>
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<b>Flexible hoses</b>	Flexible hoses may be used as flare lines or emergency flare lines if they: <ul style="list-style-type: none"><li>• Have factory installed connections.</li><li>• Maintain their original shape and do not contain bends with a radius less than the manufacturer's specified minimum bending radius.</li><li>• Are supported and protected from mechanical damage.</li></ul>
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- Are secured (if it is a non-flange hose).
- Have competent fire sheathing to withstand a minimum of 700°C flame temperature at a maximum working pressure without failure, if used within 7 meters of a well.

**Prohibition:** Flexible hoses are not permitted within 9 meters of the pressure tank.

**TVD > 3,600  
meters**

For wells with a TVD > 3,600 meters, there must be at least two flare lines installed.

## 5 Other Equipment on Site

### Contents

This section contains requirements for other equipment on the well site:

- Electrical and fired heating equipment.
- Equipment with internal combustion engines.

## 5.1 Electrical and fired heating equipment

<b>Contents</b>	<p>This section describes limitations on the use of electrical and fired heating equipment in a hazardous location, including:</p> <ul style="list-style-type: none"><li>• Electrical appliances or devices</li><li>• Electrical motors or generators</li><li>• Flame-type equipment</li></ul>
<b>Definition: hazardous location</b>	<p>A <b>hazardous location</b> is the area within 25 meters of the wellbore or any structure where combustible materials or gasses can collect.</p>
<b>Electrical appliances or devices</b>	<p><b>Prohibition:</b> Electrical appliances or devices that are a potential source of ignition are not permitted in a hazardous location.</p> <p>If the operator must use electrical devices that are a potential source of ignition in a hazardous location, the operator must:</p> <ul style="list-style-type: none"><li>• Confirm that the electrical appliance or device is specifically approved and suitable for its intended application.</li><li>• Assess on-site safety.</li><li>• Develop safety procedures for the operation.</li><li>• Review the safety assessment and procedures with the crew.</li><li>• Document the assessment and procedures in the tour report before the operation is conducted.</li></ul>
<b>Electrical motors or generators</b>	<p><b>Prohibition:</b> Electrical motors or generators that produce arcing during operation may not be placed or operated in a hazardous location unless the motor or generator is purged with an air intake located outside the hazardous location.</p>
<b>Flame-type equipment</b>	<p><b>Prohibition:</b> Flame-type equipment is not permitted in a hazardous location.</p>
<b>Definition: flame-type equipment</b>	<p><b>Flame-type equipment</b> is any equipment using an open flame. Examples include space heaters, torches, heated process vessels, boilers, electric arc or open-flame welders, stoves, furnaces, and pilot lights.</p>

## 5.2 Equipment with internal combustion engines

**Contents** This section contains information on the requirements for equipment with internal combustion engines in a hazardous location, including:

- Engine shutoff devices
- Testing requirements for shutoff devices
- Vehicles without shutoff devices
- Requirements for exhaust pipes

**Definition: hazardous location** A **hazardous location** is the area within 25 meters of the wellbore or any structure where combustible materials or gasses can collect.

**Engine shutoff devices** The acceptable shutoff devices for internal combustion engines operating in a hazardous location are shown in the table below.

Engine Type	Acceptable Shutoff Device(s)
Diesel engine – service rig	One of the following: <ul style="list-style-type: none"> <li>• Manual air intake shutoff device readily accessible from the driller’s position.</li> <li>• System capable of injecting an inert gas into the engine’s cylinders, equipped with a remote control readily accessible from the driller’s position.</li> <li>• Air intake for the engine located at least 25 meters from the well.</li> <li>• Other device approved by the Regulator.</li> </ul>
Diesel engine – other equipment	Manual engine shutoff device, readily accessible from the operator’s working position.
Gasoline engine (including propane)	Manual ignition shutoff device, readily accessible from the operator’s working position.

**Testing requirements for shutoff devices** All internal combustion engine shutoff devices must be tested:

- Before well servicing operations begin.
- Weekly after operations have begun.

Shutoff device testing results must be recorded in the daily reports and logbook.

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### Vehicles without shutoff devices

**Prohibition:** Internal combustion engines not equipped with engine shutoff devices may not operate in a hazardous location.

If the operator must use internal combustion engines not equipped with engine shutoff devices in a hazardous location, the operator must:

- Confirm that the equipment is specifically approved and suitable for its intended application.
- Assess on-site safety.
- Develop safety procedures for the operation.
- Review the safety assessment and procedures with the crew.
- Document the assessment and procedures in the tour report before the operation is conducted.

### Exhaust pipe requirements

An exhaust pipe from an internal combustion engine in a hazardous location must be constructed so that:

- Flames are prevented from emerging along its length or at its end.
- The end of the exhaust pipe is more than 6 meters away from the vertical centreline (projected upward) of the well.
- The end of the exhaust pipe is not directed toward the well.



## 6 Well Site Spacing

### Contents

This section provides information on:

- Exemptions from the minimum spacing requirements
- Minimum spacing requirements for well site equipment:
  - Table
  - Diagram

### Exemptions

If it is not possible to meet these minimum spacing requirements due to site conditions, the operator must:

- Inform the Chief Safety Officer as soon as possible.
- Submit a written request for exemption including a proposed site spacing diagram and rationale.

### Minimum spacing requirements table

The following table shows the minimum spacing requirements for well site equipment.

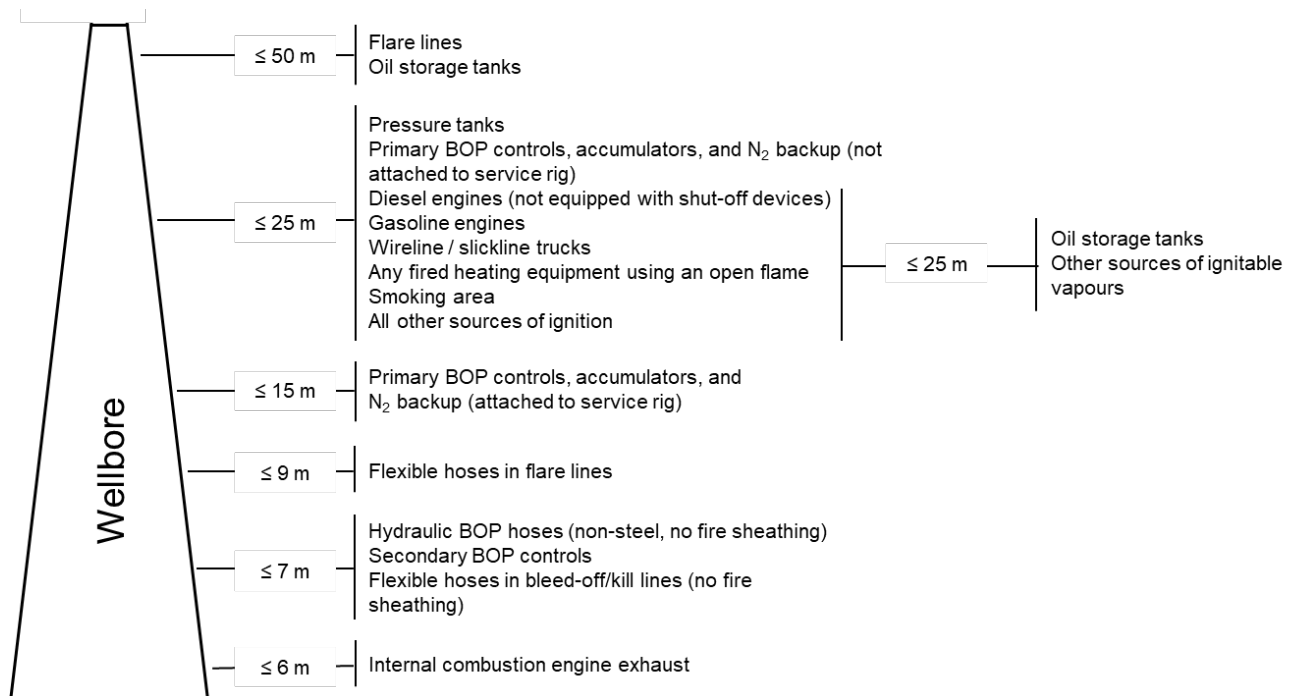
Equipment	Minimum Spacing Requirements
Internal combustion engine exhaust	Locate at least 6 meters from the vertical centreline of the wellbore.
Hydraulic BOP hoses (non-steel, without fire sheathing)	Locate at least 7 meters from the wellbore.
Secondary BOP controls	Locate at least 7 meters from the wellbore.
Flexible hoses in bleed-off/kill lines (no fire sheathing)	Locate at least 7 meters from the wellbore.
Flexible hoses in flare lines	Locate at least 9 meters from the pressure tank.
Primary BOP controls, accumulators, and N <sub>2</sub> backup	Locate at least 15 meters from the wellbore if attached to the service rig. If not attached to the service rig, locate at least 25 meters from the wellbore.
Pressure tanks	Locate at least 25 meters from the wellbore.
Diesel engines (not equipped with shut-off devices) and gasoline engines	Locate at least 25 meters from the wellbore, oil storage tanks, or other sources of ignitable vapours.

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Equipment	Minimum Spacing Requirements
Wireline / slickline trucks	Locate at least 25 meters from the wellbore, oil storage tanks, or other sources of ignitable vapours.
Any fired heating equipment using an open flame	Locate at least 25 meters from the wellbore, oil storage tanks, or other sources of ignitable vapours.
Smoking area	Locate at least 25 meters from the wellbore, oil storage tanks, or other sources of ignitable vapours.
Flare lines	Terminate at least 50 meters from the wellbore.
Oil storage tanks	Locate at least 50 meters from the wellbore

### Minimum spacing requirements diagram

The following diagram shows the minimum spacing requirements for well site equipment.



## 7 Specific Operations

### Contents

This section contains requirements for the following specific operations:

- Tripping
- Overbalanced milling
- Underbalanced milling and shallow wellbore plugs

## 7.1 Tripping

**Contents** This section contains information on the requirements for conducting tripping operations, including:

- Flow check frequency
- Flow check procedures
- Recording flow check results
- Hole filling

**Flow check frequency** Flow check frequencies are based on the direction of tripping. Operators must perform a minimum 10-minute flow check during tripping operations as described in the table below.

<b>Tripping Direction</b>	<b>Required Flow Checks</b>
Into the well	<ul style="list-style-type: none"> <li>• After running in the first 10 stands of pipe.</li> <li>• At the approximate midpoint depth (measured depth)</li> </ul>
Out of the well	<ul style="list-style-type: none"> <li>• After pulling approximate 5% of the drilling string (measured depth).</li> <li>• At the approximate midpoint depth (measured depth).</li> <li>• Before pulling the last stand of drill pipe and the drill collars.</li> <li>• After all the drilling string is pulled.</li> </ul>

**Flow check procedures** The hole must be filled to surface before conducting flow checks.

If the drill string is being circulated while tripping tubulars, flow checks must be conducted with the pump off.

**Recording flow check results** Flow checks must be recorded in the tour sheets.

**Hole filling** When tripping the drill string out of the well, the fluid level in the wellbore must not drop more than 30 meters from the surface.

The calculated and actual volumes of fluid required to fill the hole must be recorded in the tour sheets for each trip, along with the date, location, depth, and type of trip.

If the drill string is being circulated while tripping tubulars, actual hole fill volumes must be recorded on the trip sheet for at least every 100 meter interval of drill pipe removed.

## 7.2 Overbalanced milling

<b>Contents</b>	<p>This section provides information on:</p> <ul style="list-style-type: none"><li>• Mandatory disclosure</li><li>• Controlling formation pressures</li><li>• Mandatory on-site documentation for overbalanced operations</li><li>• Tripping during overbalanced operations</li></ul>
<b>Definition: overbalanced milling</b>	<p><b>Overbalanced milling</b> occurs when the hydrostatic head of a workover fluid, together with the weight of the working string, is intentionally designed to be greater than the pressure of the formation being drilled. Overbalanced milling may occur naturally or be induced.</p>
<b>Controlling formation pressures</b>	<p>The operator must ensure sufficient workover fluid density is maintained to control formation pressures throughout the well operation unless the formations have been abandoned.</p>
<b>Mandatory on-site documentation</b>	<p>The following information must be available on-site during overbalanced operations:</p> <ul style="list-style-type: none"><li>• Procedures and crew responsibilities during overbalanced operations</li><li>• Rig pump specifications</li><li>• Current well data required to control a kick</li></ul> <p>Calculations and formulas (for tubing volume, hydrostatic weight of kill fluid, casing and tubular capacities and displacements, etc.) must be as described in <a href="#">Acronyms, Formulas and Well Control Forms</a> issued by Enform (now Energy Safety Canada).</p>
<b>Tripping</b>	<p>Before tripping the work string from the well during overbalanced operations, the operator must:</p> <ul style="list-style-type: none"><li>• Maintain sufficient workover fluid density to overbalance the expected formation pressures so that formation fluids do not enter the wellbore.</li><li>• Conduct a bottom-up circulation or pump a weighted tripping pill.</li></ul>

## 7.3 Underbalanced milling and shallow wellbore plugs

<b>Contents</b>	This section provides information on: <ul style="list-style-type: none"><li>• Mandatory disclosure</li><li>• Compliance with Industry Recommended Practices (IRPs)</li><li>• Using a snubbing unit during underbalanced milling operations</li><li>• Using a coiled tubing rig during underbalanced milling operations</li><li>• Pre-operation hazard assessment</li><li>• Reporting</li></ul>
<b>Definition: underbalanced milling</b>	<b>Underbalanced milling</b> occurs when the hydrostatic head of a workover fluid is intentionally designed to be lower than the pressure of the formation being drilled. Underbalanced milling may occur naturally or be induced.
<b>Definition: shallow wellbore plug</b>	A <b>shallow wellbore plug</b> is any wellbore plug that does not allow the wellbore to be safely killed by overbalancing the plug, including a margin of safety, with weighted fluid and the working string weight. Shallow wellbore plugs result in an underbalanced milling operation.
<b>Mandatory disclosure</b>	Operators must disclose underbalanced milling operations to OROGO as soon as possible, either: <ul style="list-style-type: none"><li>• As part of the well approval application; or</li><li>• Immediately after encountered during well operations.</li></ul> The presence of a shallow wellbore plug, or suspected presence of a shallow wellbore plug based on historical records, must be disclosed in all well approval applications. The well servicing program must assume reservoir pressure is present below the plug.
<b>Compliance with IRPs</b>	Underbalanced milling operations must comply with: <ul style="list-style-type: none"><li>• The blowout prevention system requirements in Energy Safety Canada's <a href="#">IRP 22: Returns Management Drilling, Managed Pressure Drilling, and Underbalanced Drilling Operations</a> or <a href="#">IRP 15: Snubbing Operations</a>.</li><li>• The snubbing, tripping, and stripping procedures described in IRP 15, IRP 22, and these Guidelines.</li></ul>
<b>Snubbing units</b>	A snubbing unit must be installed before underbalanced milling operations begin. It must remain in place until: <ul style="list-style-type: none"><li>• Pressures are equalized; or</li><li>• The wellbore has been killed with weighted fluid.</li></ul>
<b>Coiled tubing units</b>	Coiled tubing units may be used as an alternative to snubbing units if they are rated for the maximum anticipated well bore pressure and if they are used in the manner described above.

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### Pre-operation hazard assessment

Before an underbalanced milling operation, the operator must conduct a hazard assessment. The assessment must include:

- Identifying hazards and mitigations if pressure is found.
- Reviewing BOP and evacuation procedures.
- Inspecting and securing the rig, hoses, and other equipment that may encounter pressures from the wellbore.
- Identifying danger zones and ensuring only essential staff are present and safety positioned to avoid the identified potential hazards in the immediate work area during milling operations.
- Placing the medic on standby and ensuring they are present for during the hazard assessment and all operations.

### Reporting

The pre-operation hazard assessment must be recorded in the tour sheets and submitted to OROGO at least one hour before the underbalanced milling operation begins.

Within one hour of completing the underbalanced milling operation, a summary of operations must be submitted to OROGO.

## 8 Administrative Controls

### Contents

This section contains information on the administrative controls that must be in place during service rig operations, including:

- Well site supervision
- Crew certification
- BOP drills
- Operator and contractor inspections
- On-site documentation



## 8.1 Well site supervision

<b>Contents</b>	<p>This section contains information on the requirements for well site supervision:</p> <ul style="list-style-type: none"><li>• By the operator</li><li>• By the rig manager</li><li>• During tripping operations</li><li>• During well control situations</li></ul>
<b>Definition: operator</b>	<p>The <b>operator</b> is the company named on the operations authorization issued by the Regulator for the activity.</p>
<b>Operator supervision</b>	<p>The operator must provide an on-site representative responsible for supervising the well operations. This representative:</p> <ul style="list-style-type: none"><li>• Must be on-site during operations. If the representative is making an off-site trip, they must be:<ul style="list-style-type: none"><li>○ Available within two hours' travelling time and</li><li>○ Always reachable by radio, text, or phone.</li></ul></li><li>• Cannot be the rig manager.</li><li>• Cannot supervise multiple servicing operations at the same time.</li></ul>
<b>Rig manager</b>	<p>The rig manager is responsible for supervision of the service rig. The rig manager:</p> <ul style="list-style-type: none"><li>• Must be on-site unless a relief rig manager is on site.</li><li>• Cannot supervise multiple servicing operations at the same time.</li></ul>
<b>Supervision of tripping operations</b>	<p>The operator representative or the rig manager must be on site during tripping operations when the wellbore is open to the hydrocarbon bearing zone(s).</p>
<b>Supervision of well control situations</b>	<p>The operator representative or the rig manager must be on site during well control situations.</p>

## 8.2 Crew certification

### Contents

This section describes:

- Mandatory well control certificates
- Mandatory health and safety certificates
- Requirements for valid certificates
- Consequences of unavailable certificates

### Mandatory well control certificates

The following certificates, issued by [Energy Safety Canada](#), are mandatory:

Individual	Minimum Mandatory Certificate
Operator representative	Well servicing blowout prevention
Rig manager/tool push	Well servicing blowout prevention
Driller	Well servicing blowout prevention
Coiled tubing unit operator	Coiled tubing well servicing blowout prevention

### Mandatory health and safety certificates

The following certificates are mandatory for all on-site personnel:

- Intermediate First Aid (issued by an agency that meets the requirements of the [Occupational Health and Safety Regulations R-039-2015](#))
- H<sub>2</sub>S Alive (issued by [Energy Safety Canada](#))
- WHMIS for Workers

### Valid certificates

Valid certificates are:

- Not expired (including temporary cards).
- Available for review by OROGO inspectors upon request.

### Consequences of unavailable certificates

If the mandatory certificates are not available for review by OROGO inspectors upon request, operations will be suspended (if safe to do so) until certificates are provided or qualified individuals are on site.

## 8.3 BOP drills

<b>Contents</b>	This section contains the requirements for BOP drills, including: <ul style="list-style-type: none"><li>• Frequency</li><li>• Scenarios</li><li>• Procedure</li><li>• Recording results</li></ul>
<b>Frequency</b>	BOP drills must be conducted: <ul style="list-style-type: none"><li>• Once rig is stood up and BOP installation is complete.</li><li>• When a new crew comes on site after initial BOP installation.</li><li>• Every seven calendar days (if on the same well).</li></ul>
<b>Scenarios</b>	BOP drill scenarios should rotate through all kick scenarios possible during the operation, for example: <ul style="list-style-type: none"><li>• Drilling / cleaning to bottom / circulating</li><li>• Tripping work string</li><li>• Work string is out of the well</li><li>• Tripping sucker rods</li></ul>
<b>Procedure</b>	BOP drills must be completed as described in the <a href="#">Energy Safety Canada</a> Well Service Blowout Prevention course.
<b>Recording results</b>	All BOP drills must be recorded in the tour sheets and daily reports.

## 8.4 Operator and contractor inspections

<b>Contents</b>	<p>This section provides information on mandatory inspections by operators and contractors, including:</p> <ul style="list-style-type: none"><li>• Daily inspections</li><li>• Detailed inspections</li><li>• Flare line inspections</li><li>• Recording inspections</li><li>• Reporting non-compliance</li></ul>
<b>Definition: operator</b>	<p>The <b>operator</b> is the company named on the operations authorization issued by the Regulator for the activity.</p>
<b>Daily inspections</b>	<p>Daily inspections:</p> <ul style="list-style-type: none"><li>• Are walk-arounds of the service rig to identify any rig non-compliances.</li><li>• Must be conducted in conjunction with the daily BOP three component test.</li></ul>
<b>Detailed inspections</b>	<p>Detailed inspections must review all well control and other equipment on site for compliance with these Guidelines.</p> <p>Detailed inspections must be conducted:</p> <ul style="list-style-type: none"><li>• Before entering the well with the work string.</li><li>• At least weekly during the operation.</li></ul>
<b>Flare line inspections</b>	<p>Flare lines must be inspected:</p> <ul style="list-style-type: none"><li>• Before assembly: A visual inspection of all connections between the circulation manifold and the pressure tank or degasser.</li><li>• After assembly: An inspection must be conducted to ensure proper make-up.</li></ul>
<b>Recording inspections</b>	<p>All inspections must be recorded in the tour sheets.</p>
<b>Reporting non-compliance</b>	<p>Any non-compliance (corrected or not) must be reported to OROGO in the daily report.</p>

## 8.5 Onsite documentation

<b>Contents</b>	<p>This section describes the requirements for onsite documentation, including:</p> <ul style="list-style-type: none"><li>• Blowout prevention and well control procedures</li><li>• Maximum allowable casing pressure</li><li>• Bottom hole pressure</li><li>• Wellbore diagram</li></ul>
<b>Blowout prevention and well control procedures</b>	<p>Blowout prevention and well control procedures must be posted in the doghouse.</p> <p>These procedures must include:</p> <ul style="list-style-type: none"><li>• Flow check procedures</li><li>• Kick warning signs</li><li>• Crew positions during well control situations</li><li>• Well shut-in procedures</li><li>• Well control methods</li></ul>
<b>Maximum allowable casing pressure</b>	<p>The maximum allowable casing pressure (MACP) must be posted at the circulation manifold and at the remote valve control location (where available).</p> <p>The MACP must be calculated as described in <a href="#">Acronyms, Formulas and Well Control Forms</a>, issued by Enform (now Energy Safety Canada).</p>
<b>Bottom hole pressure</b>	<p>Bottom hole pressures must be calculated prior to the start of operations as described in the <a href="#">Energy Safety Canada</a> Well Service Blowout Prevention course.</p>
<b>Wellbore diagram</b>	<p>The wellbore diagram must be posted in the doghouse.</p> <p>The wellbore diagram must be reviewed by appropriate on-site personnel before beginning well service operations.</p> <p>The wellbore diagram must include:</p> <ul style="list-style-type: none"><li>• Geological formation tops</li><li>• Cement tops</li><li>• Casing and liner description, location, and depth</li><li>• Plugs, retainers, and packer description and location</li><li>• Location of perforations</li><li>• Type of wellbore fluid</li><li>• Presence of H<sub>2</sub>S or acid gas</li><li>• Reservoir pressure</li></ul>

## 9 Regulator's Approval

These *Service Rig Operation Safety Guidelines and Interpretation Notes* are issued under section 18 of the *Oil and Gas Operations Act* effective MONTH DAY, 2025.

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Pauline de Jong  
Regulator