Chapter 9 Well Activity: Completion, Maintenance and Abandonment

9. Well Completions, Maintenance and Abandonment

Please Note:

This manual is written as a whole and provided to industry in sections to allow permit holders to access activity chapters. It is prudent of the permit holder to review the manual in its entirety and be aware of the content in other sections of the manual.

9.1 Well Equipment

Equipment must adhere to the regulatory requirements.

9.1.1 Wellheads

Wellheads are required to operate safely under the conditions anticipated during the life of the well and the wellhead is not to be subjected to excessive force. Review the ESC's IRP Volume#5: Minimum Wellhead Requirements for more information.

9.1.2 Tubing

Tubing is required for the production of gas containing greater than or equal to five per cent H_2S and for all injection and disposal except for the injection of fresh water. This excludes initial completions and/or hydraulic fracturing.

9.1.3 Packers

Operators of disposal wells, injection wells and sour gas production wells should adhere to the requirements under Section 16(2)(3) and Section 39(6) of the Drilling and Production Regulation.

Regulatory Requirements
As per the requirements in Sections 16(2)(3) and 39(6) of the Drilling and Production Regulation, a production packer must be used for:

- All disposal wells,
- Water injection wells, except fresh water injectors,
- Gas injection wells, except where the gas contains less than 5 mole percent hydrogen sulphide, and
- Producing wells that are not equipped with artificial lift, and if any of the following apply:
    - The hydrogen sulphide content of the gas equals or exceeds 5 mole percent, or
    - A populated area, or a numbered highway is within the emergency planning zone for the well.

"Populated area" means a dwelling, school, picnic ground or other place of public concourse.

Sections 16(2)(3) and 39(6) of the Drilling and Production Regulation also states the permit holder must:

- Install a production packer set as closely above the producing/disposal interval as is practicable.
- Ensure that the space between tubing and the outer steel casing is filled with a corrosion and frost inhibiting fluid.
- Conduct annual segregation tests and, if the test fails, complete repairs without unreasonable delay, and
- Submit within 30 days of completion a record of the tests and repairs.

Packer Isolation Test
Annual packer isolation testing is required for all regulated packer installations. A packer isolation test confirms that the portion of the wellbore, i.e., casing-tubing annulus above the packer set depth, is segregated from the other portions of wellbore and formations to prevent pressure and fluid communication.

Preparation/Conditions for Testing
Maintain stable operations at least 12 hours prior to and throughout the test period. Failure to maintain stable operating conditions may result in unreliable test results and further testing may be required.

The Regulator recommends conducting the packer isolation test while the well is shut-in.

In the event there is no plan to shut-in a well in the year and the packer isolation test has to be conducted during injection or production, care must be taken to ensure injection or production operations occur at a stable condition, e.g., maintaining a consistent production rate for a producer, or consistent injection rate and fluid temperature for an injection or a disposal well.

If a packer isolation test is conducted during a workover, there should be no activity on the well between the 10 minute test and the 24 hour test, and during the 24 hour test.

Test Procedure

1. Upon arrival on site:
   - Check if there is any indication of a leak, e.g., stain or wet area on the ground surface below a connection or a plug,
   - Take pictures of any observed leak, and
   - Record initial casing and tubing pressure.
2. If the casing pressure is higher than 0 kPa, bleed down the casing pressure as low as possible (should be very close to 0 kPa):
   - Allow the pressure to stabilize for 10 minutes,
   - Record whether there is combustible gas from the casing-tubing annulus during bleed-off.
   - Record a description of the liquid from the annulus during bleed-off, if any e.g., diesel, yellow color liquid mixture.
   - Record the volume of liquid recovered, if any, during bleed-off.

   Note: An inability to bleed the casing pressure to near 0 kPa may indicate a presence of an integrity issue.
3. Conduct a 10-minute pressure test at 1,400 kPa or the preferred testing pressure:
   - Determine the preferred pressure testing level:
     - If the difference between tubing pressure and 1400kPa is less than 1400kPa, it is recommended to select another pressure level that can ensure the tubing– casing pressure difference is at least 1400kPa for the pressure test.
   - Pump testing fluid into casing-tubing annulus to 1,400 kPa or the preferred

pressure level.

- Record the type and volume pumped of the testing fluid.
- Allow pressure to stabilize:
    - The “stabilized” status or “stabilization” here means the situation that the pressure change with time is close to a constant.
- After stabilization, record the start casing pressure and end casing pressure for the selected 10-minute period.
- Monitor the surface casing vent assembly during the test and record whether any liquid is emitted from it.

Note: Failure to achieve the determined test pressure after pumping a large volume of water may indicate the presence of an integrity issue.

4. Conduct a 24-hour pressure buildup test:

- Bleed-off casing pressure to the lowest level, which should be close to 0 kPa, and allow the pressure to stabilize for 10 minutes.
- Record a description and the volume of any liquid recovered during the pressure bleed-off.
- Record the casing shut-in pressure for 24 hours using a chart, digital recorder, or other continuous monitoring method.

Note: If the 24-hour test does not result in a “pass” result, possibly as a result of thermal effects, conducting a second 24-hour buildup test is recommended.

Test Result

A Packer Isolation Test is a considered a pass when all of the following conditions are met:

1) The pressure change during the 10 minute test is less than 3%,
2) The pressure increase throughout the 24 hour test is less than 42 kPa, OR if there is a record from SCADA (or equivalent) that shows a successful 24-hr buildup test,
3) There was no liquid from surface casing vent assembly during the test,
4) The pressure-up and bleed-down in the casing-tubing annulus did not cause a change in the tubing pressure,
5) Combustible gas was not detected during casing-tubing annulus pressure bleed down,
6) There are no other indications of an integrity issue.

Packer Isolation Test Report Submission
A Packer Isolation Test submission must include all information described above, all graphs of casing pressure vs. time obtained during Step 3 and Step 4, and/or any other, optional, documents related to the test. The Packer Isolation Test report must be submitted to the Regulator through eSubmission. Guidance for submitting PIT reports can be found in the updated eSubmission User Guide.

A printable version of the PIT Form, identifying all information required in eSubmisison, is available on the Regulator's website.

This form is made available for reference purposes only; scanned copies of this form will not meet submission requirements, but may be included as an attachment.

9.1.4 Subsurface Safety Valves

In accordance with Section 39 (6) of the Drilling and Production Regulation, subsurface safety valves may be required in cases where the H_2S content of the gas exceeds 5%, or where a populated area or numbered highway is located within the emergency planning zone.

In the above cases, a subsurface safety valve is required if:

a) The calculated AOF, under current conditions, is greater than 30 E3m3/d, and
b) The well is located within 800m of a populated area, or within 8km of a city, town or village

Unless specified otherwise in an Order approving an acid gas disposal well, subsurface safety valves are required for all acid gas disposal wells.

As per section 16(1)(a) of the Drilling and Production Regulation, function testing of the subsurface safety valve is to be done in accordance with the manufacturer's recommendation, or sound engineering practices. Function testing, maintenance and inspection requirements may also be specified in an Order approving a well for use as an acid gas disposal well. Guidance on acceptable leak rates can be found in the American Petroleum Institute's (API) RP 14B: Design, Installation, Repair and Operation of Subsurface Safety Valve Systems errata document.

In general, the distance from a city, town or village should be measured from the corporate limits. In cases where the corporate limits do not reasonably correspond with the boundaries of the community, the permit holder may take a functional approach such as delineation of the extent of developed areas.

9.1.5 Oil Wells

Oil wells completed after October 4, 2010 equipped with an artificial lift, if the H_2S content of the gas exceeds 100 ppm, must install the following:

- If a pumpjack is the method of artificial lift:
  - install on the stuffing box a device that will seal off the well in the event of a polish rod failure, and
  - Automatic shutdown on the stuffing box that will shut down the pumping unit in the event of a stuffing box or polish rod failure.
  - Automatic vibration shutdown system.
- If a pumpjack is not used as an artificial lift, maintain a system that will shut down the artificial lift if a leak is detected.

9.1.6 Fencing

Permit holders of completed wells that:

- Are located within 800 metres of a populated area.
- Have a populated area within the emergency planning zone of the wells.

Fencing or other suitable measure to prevent unauthorized access to the well must be installed. An exemption can be requested if the intent of section 39 of the Drilling and Production Regulation is met or exceeded. For wells that are located on private land, the method of access control should be developed in consultation with the landowner.

9.2 Well Servicing Operations

9.2.1 Notice of Operations

A Notice of Operation (NOO) must be submitted for all work being performed on a well. This includes initial completions, completions workovers, abandonments and maintenance. The complete list can be found in the Regulator's Notice of Operations and Completion / Workover Report Reference Guide. The NOO is to be submitted electronically through the eSubmission portal on the Regulator's website. The Notice of Abandonment is submitted through eSubmission under Well Decommissioning.

The Notice of Operations submission requires the well authorization number and is submitted using eSubmission portal within at least 24 hours prior to the start of completion operations. Notice of Operations submitted at least 7 days prior to the start of abandonment operations.

If an activity at a well is expected to result in gas being flared, a Notice of Flare must be submitted using the eSubmission Portal. This Notice may be submitted in conjunction with a Notice of Operation if a well operation is taking place, or as a standalone submission.

To report actual flare volumes, ensure all volumes flared at a well are included in production reporting via Petrinex.

Please Note:

Shallow Fracturing operations at a depth of 600 metres or less must be approved in the well permit. Refer to the Commission's Oil and Gas Activity Application Manual for more information.

9.2.2 Inter-wellbore Communication

Subject well permit holders (the well undergoing hydraulic fracture stimulation) are obligated to manage the risks of inter-wellbore communication between the subject well and an offset well. The subject well permit holder must have a documented hydraulic fracturing program that includes the following elements:

- Identify all offset wells that could be affected.
- Conduct a risk assessment of the identified offset wells.
- Develop a well control plan for all offset wells that are at risk.
- Modify the hydraulic fracturing program if risks cannot be mitigated.

The subject well permit holder must notify the permit holder of an at-risk offset well of its planned hydraulic fracturing program and make all reasonable efforts to develop a mutually-agreeable well control plan. The subject well permit holder must maintain a copy of the at-risk well control plan for the duration of hydraulic fracturing operations.

The permit holder of an at-risk offset well, upon receiving notification of a planned hydraulic fracturing program, is expected to engage and work cooperatively with the subject well permit holder in development of well control plans.

During the design and execution of the fracturing program, the subject well permit holder must ensure the fracture will not extend into any unintended formations. Any communications with unintended formations are in conflict Section 22 of the Drilling and Production Regulation.

All fracture communication "incidents" must be reported in accordance with the Regulator's Incident Reporting Instructions and Guidelines. An incident means the communication resulted in a spill, equipment overpressure, equipment damage, injury or drilling kick. For inter-wellbore communications, a kick is defined as a pit gain of three cubic metres or greater, or a casing pressure of 85 per cent of the Maximum Allowable Casing Pressure (MACP).

Communication events should be reported even if contact did not reach the defined “incident” level. A database of all communication events will further the understanding of the resource and assist in the development of effective technology.

Permit holders are requested to report all fracture communication events using the Inter-Wellbore Communication Report Form. Permit holders are also expected to follow the ESC’s Industry Recommended Practice 24 for specific methodology and procedures regarding the inter-wellbore communication management process.

9.2.3 Multi-zone or Commingled Wells

Refer to Section 23 of the Drilling and Production Regulation.

All zones in a well must remain segregated unless permission has been granted for commingled production. Permission may be granted in an individual well permit or by a special project for commingling under Section 75 of ERAA.

For information and guidelines in regards to commingling, including forms and requirements, refer to the Commingling section within the Reservoir Engineering documentation page on the Regulator’s web site.

The Notification of Commingled Well Production form must be submitted to the Regulator within 30 days of the commencement of commingled production.

9.3 Well Suspension

Activity means:

- Production, injection or disposal of fluids.
- Drilling, completion or workover operations.

Inactive well means a well that has not been abandoned but:

- Has not been active for 12 consecutive months.
- If the well is classified as a special sour or an acid gas disposal and has not been active for six consecutive months.

For active production, injection and disposal wells, the date of the last activity is defined as the first day of the month following the last month for which production, injection and disposal volumes were reported. Observation wells are deemed to be active (see section 9.3.1 of this manual).

Well Suspension Activity Dates

- For active production, injection and disposal wells, the date of last activity is defined as the first day of the month following the last month for which production, injection and disposal volumes were reported.
- For drilling activity, including new wells and re-entries, the date of last activity is defined as the rig release date.
- For completion and workover activity, the date of last activity is defined as the completion date.

A permit holder may apply to the Regulator to declassify a special sour well. The context here is that as production rates fall, the H_2S release rate may fall such that the well no longer should be classified as a special sour well.

9.3.1 Observation Wells

The Drilling and Production Regulation defines that a well or a portion of a well may be designated as an observation well under Section 2(7). Reservoir observation wells typically gather data on:

- Formation pressure, fluid quality or fluid migration related to production, injection or disposal.
- Monitoring well completion operations (microseismic) or seismicity observation.

For use of either a purpose-drilled well, or conversion of an existing production or injection well to observation type, an application and approval is required from the Reservoir Engineering Department of the Regulator. An observation well designation under Section 2(7) contains conditions for monitoring, data collection and reporting to maintain a valid designation. After issuing approval, the Regulator will update the well status to reflect the observation well designation.

A well permit holder must ensure that the static bottom hole pressure of each observation well is measured at least once per calendar year, unless stated otherwise in the approval. All static bottom hole pressure measurements and resulting shut-in time must be reported to the Regulator.

Observation wells are treated as active and do not require suspension unless observation designation is withdrawn:

- Observation well designation may be withdrawn if approval conditions are not met.

9.3.2 Suspension Requirements

All wells must be suspended within 60 days of attaining inactive status in a manner that ensures the ongoing integrity of the well.

Any well may be suspended to a higher standard than the minimum requirements described in Tables 9A to 9D. Reporting requirements are described in Section 9.5.1.

Permit holders may apply to the Regulator Drilling and Production department for an extension of a deadline.

The following tables describe the Regulator's minimum requirements for each category.

Table 9A: General Requirements for All Inactive Wells

Annual Inspection	Annual inspections include the requirements from the following sections: • Visual Inspection • Wellhead maintenance • Surface casing vent flow (if applicable) • Lease maintenance
Wellheads	Unperforated wells may use a welded steel plate atop the production casing stub. The plate must provide access to the wellbore for pressure measurement. All other wells must use standard wellheads as described in Energy Safe Canada (ESC)'s IRP Volume #2 (Completing and Servicing Critical Sour Wells) and IRP Volume #5 (Minimum Wellhead Requirements).
Wellhead Maintenance	There shall be no wellhead leaks. Pressure recording must be taken from all annuli and production conduit. Bullplugs or blind flanges with needle valves must be installed on all outlets except the surface casing vent. The surface casing vent valve must be open and the surface casing vent unobstructed unless otherwise exempted by an official. All valves must be chained and locked or valve handles must be removed. The flowline must be disconnected or isolated from the wellhead. Isolation does not include a valve. Polish rod removal is not required to suspend low risk oil wells as long as the polish rod remains connected to the pump jack.
Pressure testing seals	Low Risk and Medium Risk wells, do not require seals to be pressure tested if integrity can be proven. Criteria for proving integrity are: • The well does not have a Surface Casing Vent Flow OR • If a positive pressure test is achieved on the casing string of which the seals are isolating AND • There is no evidence of failed seals based on the pressure in the intermediate casing string (if applicable)

	Must indicate the method of confirming seal integrity on suspension report. For wellheads that do not have adequate test ports, pressure tests may be omitted and visual observation for leaks is acceptable. An explanatory note must be included on the well suspension report. High risk wells must pressure test the seals.
Surface Casing Vent Flows and Gas Migration	Surface casing vent flows and gas migration occurrences are to be managed and reported in accordance with Regulator requirements. See Sections 9.7.3 through 9.7.5 (surface casing vent flow) and 9.7.6 (gas migration) of this manual for more information.
Lease Maintenance	A sign stating the well's surface location, current permit holder, the current permit holder's emergency contact number and appropriate warning symbols as defined in Section 15 of the Drilling and Production Regulation must be in place. An area of 10 metres radius around the wellhead must be maintained to prevent brush from growing and causing a fire hazard. Noxious weeds must be controlled. Hazards associated with, but not limited to, pits, rat hole and storage materials, must be limited.
Visual Inspection	A visual inspection of the lease and wellhead must be conducted at least yearly to observe for wellhead integrity, noxious weeds and other hazards. For wells with helicopter access (limited year-round access), the visual inspection frequency is the pressure testing / monitoring frequency.
Reporting	Update the status of the well event in Petrinex. If the suspension of a wellbore requires a subsurface well operation, then a Notice of Operations and Completion/Workover report must be submitted as per section 9.2.1 and 9.8.1 of this Manual. A Well Suspension/Inspection report must be submitted via eSubmission within 30 days of the suspension of the wellbore. All pressure test reports must be submitted through the eSubmission portal. For information regarding pressure testing frequency, please refer to Tables 9B, 9C and 9D. When submitting a suspended well pressure test report, the annual suspended well inspection for that year must also be submitted through the eSubmission portal.
Downhole Abandoned	If all zones in a non-special sour well are abandoned and the well has not yet been surface abandoned, the well shall be categorized as "Low Risk - All cased wells (no perforations or open hole)".

Special Sour and Acid Gas Disposal	For classification criteria for special sour wells, see section 8.4.9 of this manual. For re-classification and other information see section 9.4 of this manual. Before suspension is considered, see Directive 20 Level-A requirements. It is preferred to conduct a zonal abandonment rather than a suspension. If a zone is deemed at capacity, the well should be abandoned.

Table 9B: Requirements Specific to Inactive High Risk Wells

Well Types	Type 1: Special sour wells[1]. Type 2: Acid gas disposal wells.	
Suspension Options	Option A	Option B
Downhole Requirements	Bridge plug or packer and tubing plug.	Bridge plug capped with 8 m lineal of cement.
Pressure Testing / Monitoring / Servicing Requirements	Pressure test both tubing and annulus to 7 MPa for 10 minutes. Service and pressure test wellhead sealing elements.	Pressure test the casing to 7 MPa for 10 minutes. Service and pressure test wellhead sealing elements (if applicable).
Pressure Testing / Monitoring / Servicing Frequency	At the time of suspension and then annually.	At the time of suspension and then every 5 years.
Wellbore Fluid	Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected by the use of a non-freezing fluid.	Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected by the use of a non-freezing fluid.

[1] If applicable, install a bridge plug or packer and tubing plug within 100 metres of the liner top on uncompleted special sour wells. If this option is used, ensure the plug is placed within zone or 15 meters or perforations. This Regulator encourages Permit Holders to review AER Directive 20 prior to suspending a Level-A well.

Table 9C: Requirements Specific to Inactive Medium Risk Wells

Well Types	Type 1: Medium risk gas wells (see Appendix C for more information). Type 2: Non-flowing oil wells ≥ 5% H_2S. Type 3: Flowing oil wells[2]. Type 4: All injection and disposal wells except for acid gas disposal wells. Type 6: Completed low risk wells that became inactive on or before 2009-05-30. Type 7: All non-special sour cased wells that became inactive on or before 2009-05-30.		
Suspension Options	Option A (All types)	Option B (All types)	Option C (type 7 only)
Downhole / Wellhead Requirements	Packer and tubing plug.	Bridge plug.	N/A
Pressure Testing / Monitoring / Servicing Requirements	Pressure test both the tubing and annulus to 7 MPa for 10 minutes. Service wellhead.	Pressure test the casing to 7 MPa for 10 minutes. Service wellhead.	Pressure test the casing to 7 MPa for 10 minutes. Service wellhead.
Pressure Testing / Monitoring / Servicing Frequency	At the time of suspension and then every 3 years.	At the time of suspension and then every 5 years.	At the time of suspension and then every 5 years.
Wellbore Fluid	Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected by the use of a non-freezing fluid.	Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected by the use of a non-freezing fluid.	Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected by the use of a non-freezing fluid.

[2] Flowing oil wells are oil wells **with** sufficient reservoir pressure to sustain flow against atmospheric pressure without artificial lift. The flowing product is a fluid.

Table 9D: Requirements Specific to Inactive Low Risk Wells

Well Types	Type 1: All non-special sour cased wells (no perforations or open hole sections). Type 2: Low risk gas wells (see Appendix D of this manual). Type 3: Water source wells. Type 5: Non-flowing[3] oil wells < 50 mol/kmol H_2S.	
Suspension Options	Option A (Types 2,3 and 5 only)	Option B (Type 1 only)
Downhole Requirements	None.	None.
Pressure Testing / Monitoring / Servicing Requirements	Read and record shut-in tubing pressure (if applicable) and shut-in casing pressure. Pressure test wellhead seals. Service wellhead.	Pressure test casing to 7 MPa for 10 minutes. Service wellhead.
Pressure Testing / Monitoring / Servicing Frequency	At the time of suspension and then every 5 years. After 10 years of inactivity annually.	At the time of suspension and then every 5 years.
Wellbore Fluid	None.	Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected by the use of a non-freezing fluid.

[3] Non-flowing oil wells are oil wells **without** sufficient reservoir pressure to sustain flow against atmospheric pressure without artificial lift. The flowing product is a fluid. Removal of polish rods is not required to suspend low-risk oil wells as long as the polish rod remains connected to the pump jack.

9.3.3 Packer Testing

Wells requiring installation and yearly testing of a production packer are exempt from the testing requirements if the well is suspended in accordance with the Drilling and Production Regulation. Information on packer isolation testing procedures is available in the Regulator's Water Service Wells Summary Information document.

9.3.4 Long Term Inactive Wells

For information and requirements regarding long term inactive wells, refer to the Dormancy and Shutdown Regulation and associated guidance.

9.3.5 Reactivating Suspended Wells

The following procedures should be followed for the reactivation of a suspended well.

- All Wells:
  - Inspect, service and pressure test the wellhead.
  - Inspect and service control systems and lease facilities.
- Low Risk Type 1, Medium and High-Risk Wells:
  - Pressure test the casing to 7 MPa for 10 minutes (if applicable). If the test fails, investigate and repair the problem.
  - Pressure test the tubing (if present) to 7 MPa for 10 minutes. If the test fails, investigate and repair the problem.

Reactivating Suspended Wells to Water Source Wells

Permit amendments are required for converting an existing suspended well into a water source well. Specific requirements are described in the Regulator's Supplementary Information for Water Source Wells document.

9.4 Suspended Well Reporting Requirements

9.4.1 Regulator Reporting

Well Suspensions

A Well Suspension / Inspection Report must be submitted to the Regulator's, Drilling and Production Department within 30 days of suspension of a well. The completed suspension report must be submitted through the eSubmission portal.

All downhole activities to plug and suspend are considered Workover operations and must be submitted to the Regulator in a Completion/Workover Report. Suspensions are to be reported as Workovers on report cover pages and in Notices of Operation. Refer to the Well Data Submission Requirements Manual for further information.

Reactivations

Submission of a reactivation report is not required. Reactivations are identified by alternate means (i.e. spud date, production reporting).

Inspections and Pressure Tests

All pressure test reports must be submitted through the eSubmission portal. For information regarding pressure testing frequency, please refer to Tables 9B, 9C and 9D of this manual.

When submitting a suspended well pressure test report, the annual suspended well inspection for that year must also be submitted through the eSubmission portal.

9.5 Well Abandonment

Notice of Operation is not required for conducting open hole plugbacks or abandonments before the release of the drilling rig. Permit holders are expected to conduct plugbacks or abandonments of wells being drilled as described in Chapter 3 of the Well Decommissioning Guidelines. If the plugback or abandonment is non-routine the operator must contact the Regulator's drilling engineer to discuss the plugback or abandonment program. The open hole plugbacks or abandonments should be reported into the Summary Report of Drilling Operations.

Drilling wells that are downhole, but not surface abandoned at the time of rig release, are not considered abandoned. An abandonment notification and abandonment report must be submitted to the Regulator at the time of surface abandonment as outlined below for the well status to be changed to abandoned.

9.5.1 Abandonment Notification

Notification is required 7 days prior to conducting all other well abandonments; however the notification requirement may be waived on a case by case basis. An abandonment program and current wellbore schematic is a required submission. The Notice of Abandonment is submitted through eSubmission under Well Decommissioning. For further guidance please reference the Notice of Abandonment and Abandonment Report eSubmission Permit Holder Guide on the Regulator's website.

9.5.2 Abandonment Procedures

Wells must be abandoned in a manner to ensure:

- Adequate hydraulic isolation between porous zones.
- Fluids will not leak from the well.
- Excessive pressure will not build up in any portion of the well.
- Long-term integrity of the wellbore is maintained.

For the wells only with conductor casing, permit holders are expected to conduct abandonments and plugbacks in accordance with the Groundwater Protection Regulation (Water Sustainability Act).

For water supply wells associated with oil and gas sites, permit holders are required to conduct abandonments and plugbacks in accordance with the Groundwater Protection Regulation (Water Sustainability Act).

For a water source providing water for waterflood and fracturing, the permit holder:

- is expected to conduct abandonment and plugback in accordance with the Well Decommissions Guidelines in case that the total depth of the well is deeper than the base of ground water protection, or
- is required to conduct abandonment and plugback in accordance with the Groundwater Protection Regulation (Water Sustainability Act) and Section 26(1) of Drilling and Production Regulation in case that the total depth of the well is equal to or shallower than the base of usable groundwater.

For the wells drilled for oil and gas activities, permit holders are expected to conduct abandonments and plugbacks in accordance with the Well Decommissions Guidelines.

If there is any doubt about the adequacy of a plugging or abandonment program, discuss the abandonment plans with the Regulator. Failure to adequately plug or abandon a well may result in an order for remedial work.

The Abandonment reports may be submitted using a Completion/Workover Report Form to be uploaded in the Abandonment portal and is required to be submitted with any Notice of Abandonment submitted prior to the new Notice of Abandonment portal.

In cases where a well was cut and capped, but not reported to the Regulator at the time the work was completed, the Regulator will accept the following as evidence of cut and cap:

- A photograph of the signpost (grave marker) and wellsite. The signpost must contain adequate identifying information.
- Copies of invoices / welder's tickets for the work.

If the above materials are unavailable, excavate and photograph the casing stub.

9.6 Well Servicing Equipment and Procedures

9.6.1 Blowout Prevention

The following section outlines blowout prevention standards that a permit holder should follow to comply with the requirements of Part 4, Division 2 of the Drilling and Production Regulation. It is the responsibility of the permit holder to ensure that blowout prevention equipment and procedures are adequate.

A permit holder may use alternate blowout prevention equipment and techniques if they can demonstrate by means of a detailed engineering analysis that the alternate equipment or techniques are adequate as required by Section 16(1) of the Drilling and Production Regulation.

9.6.2 BOP Equipment Classes

For the purposes of well servicing, blowout prevention equipment classes are as follows:

- Class A equipment is required for a well where the minimum pressure rating of the production casing flange is less than or equal to 21,000 kilopascals (kPa) and the hydrogen sulphide content in a representative sample of the gas is less than one mol per cent.

- Class B equipment is required for a well where the minimum pressure rating of the production casing flange is:
    - Greater than 21,000 kPa.
    - Less than or equal to 21,000 kPa and the hydrogen sulphide content in a representative sample of the gas is one mol per cent or greater.
- Class C equipment is required for a special sour well.
- Minimum stack components shall conform to the BOP stack configuration as shown in Appendix B of this manual.
- Minimum manifold design shall conform to a Class B manifold.
- Shear rams are required for special sour wells.
- All metallic BOP components which may be exposed to sour effluent must be certified as being manufactured from materials meeting the requirements of NACE MR-01-75.
- Flanged BOP working spools with two flanged side outlets are required on critical sour wells.
- Working spool outlets must include full opening gate valves to serve as primary control. The kill side shall include a primary valve and a check valve, while the bleed off line shall have a primary and a secondary (back-up) valve. The valves shall be rated to a working pressure equal to or greater than the BOP.

9.6.3 General

At all times during well servicing, the well must be under control, adequate blowout prevention equipment must be installed and must be able to shut off flow from the well regardless of the type or diameter of tools or equipment in the well.

The blowout prevention equipment must have a pressure rating equal to or greater than the pressure rating of the production casing flange or the formation pressure, whichever is the lesser.

Hydraulic ram type blowout preventers which are not equipped with an automatic ram locking device must have hand wheels available.

An accurate pressure gauge to determine the well annulus pressure during a well shut-in must be either installed or readily accessible for installation.

A service rig used at the well site must have an operable horn on the drilling control panel for sounding alerts.

A sour service separator and flare system, including appropriate manifolding, must be used to process sour well effluent.

The well control system must be adequately illuminated.

9.6.4 Accumulator systems

All blowout preventers must be hydraulically operated and connected to an accumulator system.

The accumulator system must be installed and operated in accordance with the manufacturer's specifications. The system must be:

- Connected to the blowout preventers with lines of working pressure equal to the working pressure of the system, and within seven metres of the well, the lines must be of steel construction unless completely sheathed with adequate fire resistant sleeving.
- Capable of providing, without recharging, fluid of sufficient volume and pressure to effect full closure of all preventers, and to retain a pressure of 8,400 kPa on the accumulator system.
- Recharged by a pressure controlled pump capable of recovering the accumulator pressure drop resulting from full closure of all preventers within 5 minutes.
- Capable of closing any ram type preventer within 30 seconds.
- Capable of closing the annular preventer within 60 seconds.
- Equipped with readily accessible fittings and gauges to determine the pre-charge pressure.
- Equipped with a check valve between the accumulator recharge pump and the accumulator.
- Connected to a nitrogen supply capable of closing all blowout preventers installed on the well.

The accumulator nitrogen supply must:

- Be capable of providing sufficient volume and pressure to fully close all preventers and to retain a minimum pressure of 8,400 kPa.
- Have a gauge installed, or readily available for installation, to determine the pressure of each nitrogen container.

9.6.5 Requirements Specific to Class A Systems

Class A blowout prevention system:

- May utilize the rig hydraulic system to recharge the accumulator.
- Must have operating controls for each preventer in a readily accessible location near the operator's position and an additional set of controls located a minimum of 7 metres from the well.

9.6.6 Requirements Specific to Class B and C Systems

Class B and Class C blowout prevention system must have:

- An independent accumulator system with operating controls for each preventer located at least 25 metres from the well, shielded or housed to protect the operator from flow from the well.
- An additional set of controls in a readily accessible location near the operator's position.
- Working spools with flanged outlets.

Refer to IRP#2 for further information.

9.6.7 Flow Line Requirements

The following requirements do not apply to snubbing units and service rigs completing rod jobs. A blowout prevention system must have two lines, one for bleeding off pressure and one for killing the well, which must:

- Be either steel or flexible sheathed hose to provide adequate fire resistant rating.
- Be valved and have a working pressure equal to or greater than that required for the blowout prevention equipment.
- Have one line connected to the rig pump and one line connected to the tank.
- Be at least 50 mm nominal diameter.
- Be securely tied down.

9.6.8 Stabbing Valve

A full opening ball valve (stabbing valve) which can be attached to the tubing or other pipe in the well must:

- Be ready for use and located in a readily accessible location on the service rig.
- Be maintained in the open position.
- Have an internal diameter equal to or greater than the smallest restriction inside the tubing or casing.
- Be kept clean and ice free.

9.6.9 Blowout Prevention Manifold

The blowout prevention system must include a manifold that:

- Has a working pressure greater than or equal to that of the blowout prevention system installed on the well
- Contains a check valve to prevent flow from well to rig pump
- Contains a pressure relief valve upstream of the check valve
- Is equipped with an accurate pressure gauge which shall be either installed or readily accessible for installation.

9.6.10 Testing of Blowout Prevention Equipment

Before commencing servicing operations at a well, a 10-minute pressure test must be conducted on each ram preventer to 1,400 kPa, prior to the tests described as follows:

- Each ram preventer, the full opening safety valve and the connection between the stack and the wellhead, tested to the wellhead pressure rating or the formation pressure, whichever is less.
- Each annular preventer to 7,000 kilopascals or the formation pressure, whichever is less. For an annular type blowout preventer, all mechanical and pressure tests must be conducted with pipe in the blowout preventer.

All blowout prevention equipment, except for shear rams on special sour wells, must be mechanically tested daily, if operationally safe to do so; any equipment found defective must be made serviceable before operations are resumed.

A pressure test is considered a pass if the pressure decrease is less than 10% over the 10 minute test.

All tests must be reported in the servicing log book and in the case of a pressure test, the report must state the blowout preventer tested, the test duration and the test pressure observed at the start and finish of each test.

At least once every three years, all blowout preventers must be shop serviced and shop tested to their working pressure and the test data and the maintenance performed must be recorded and made available to an official on request.

9.6.11 Special Sour Wells

Refer to Energy Safe Canada (ESC)'s IRP Volume #2: Completing and Servicing Critical Sour Wells for detailed information.

9.6.12 Slickline, Snubbing and Coil Tubing Operations

- Refer to the ESC's IRP Volume #13: Slickline Operations.
- Refer to the ESC's IRP Volume #15: Snubbing Operations.
- Refer to the ESC's IRP Volume #21: Coiled Tubing Operations.

9.6.13 Hammer Unions

Hammer unions should not be used in the manifold shack or under the rig substructure.

9.6.14 Personnel Certification

The following people must possess a valid Well Service Blowout Prevention certificate issued by Energy Safe Canada (ESC), or a Well Intervention Pressure Control Level 4 certificate issued by IWCF, or a WellSharp Oil and Gas Operators Representative certificate (WSOGOR) issued by IADC:

- The driller on tour.
- The rig manager (tool push).
- The permit holder's representative.

If gas containing H_2S is expected, every crew member must be trained in H_2S safety.

Blowout prevention drills should be performed by each rig crew every seven days or once per well, whichever is more frequent. Blowout prevention drills should be recorded in the servicing log book.

Evidence of the qualifications of any person referred to in this section must be made available to an official on request.

The rig crew must have an adequate understanding of, and be able to operate, the blowout prevention equipment and, when requested by an official and if it is safe to do so, the contractor or rig crew must:

- Test the operation and effectiveness of the blowout prevention equipment.
- Perform a blowout prevention drill in accordance with the Well Control Procedure placard issued by the Canadian Association of Oilwell Drilling Contractors (CAODC) or as outlined by the ESC Blowout Prevention Manual.

Refer to the ESC's IRP Volume #7: Standards for Wellsite Supervision of Drilling, Completions and Workovers for more information.

9.6.15 Fire Precautions and Equipment Spacing

Refer to Sections 45 and 47 of the Drilling and Production Regulation.

Engines

Permit holders must ensure that, if engines are located at a wellsite, suitable safeguards are installed and tested to prevent a fire or explosion in the event of a release of flammable liquids or ignitable vapours.

For engines located within 25 metres of a well, petroleum storage tank or other unprotected source of ignitable vapours, the Regulator recommends that:

- The engine exhaust pipe is insulated or cooled to prevent ignition in the event that flammable material contacts the exhaust pipe.
- The exhaust pipe is directed away from the well or source of ignitable vapours.
- The exhaust manifold is sufficiently shielded to prevent contact with flammable materials.

For diesel engines located within 25 metres of a well, the Regulator recommends that one of the following devices be installed:

- A positive air shutoff valve, equipped with a readily accessible control.
- A system for injecting inert gas into the engine's cylinders, equipped with a readily accessible control.

- A suitable duct so that air for the engine is obtained at least 25 metres from the well.

Permit holders must also ensure compliance with the requirements in Work SafeBC's (Section 23.8) Occupational Health and Safety Regulation.

Fuel

Gasoline or liquid fuel, except for fuel in tanks that are connected to operating equipment, must not be stored within 25 metres of a well and drainage must be away from the wellhead.

Smoking

Smoking is prohibited within 25 metres of a well.

Recommended Spacing Distances

Ensure appropriate spacing is maintained between potential sources of flammable liquids or ignitable vapours and ignition sources. All fires must be sufficiently safeguarded and equipment from which ignitable vapours may issue must be safely vented.

Flares and incinerators must be located at least 80 metres from any public road, utility, buildings, installation, works, place of public concourse or reservation for national defence.

Refer to Table 9E.1 and Table 9E.2 of this document for wellsite spacing requirements.

In a case the required spacing distances listed in Tables 9E.1 and 9E.2 cannot be met due to the wellsite restrictions, the permit holder must conduct a hazard assessment for the spacing variance to identify the hazards and put in place mitigations. A sample Wellsite Spacing Variance Hazard Assessment Form is available on the Regulator's website. Permit holders are encouraged to use their own hazard assessment format as long as all the points in the sample form are covered. Permit holders should submit the hazard assessment to the Regulator and discuss with the Regulator Drilling and Production group about the operational safety.

Table 9E.1: Wellsite Spacing Requirements

	Wellhead	Flare Or Incinerator	Boiler, Steam Generating Equipment, Teg*	Produced Water Tank	Other Sources Of Ignitable Vapours	Separator	Flame Type Equipment	Produced Flammable Liquids Crude Oil & Condensate Tanks
Wellhead		50	25	Ns	Ns	Ns	25*	50
Flare Or Incinerator	50		Ns	25	25	25	25	50
Boiler, Steam Generating Equipment, Teg*	25	Ns		25	25	25	25	25
Produced Water Tank	Ns	25	25		Ns	Ns	25*	Ns
Other Sources Of Ignitable Vapours	Ns	25	25	Ns		Ns	25*	Ns
Separator	Ns	25	25	Ns	Ns		25*	Ns**
Flame Type Equipment	25*	25	25	25*	25*	25*	T	25*
Produced Flammable Liquids Crude Oil & Condensate Tanks	50	50	25	Ns	Ns	Ns**	25*	

All distances are in metres (M). * 25 m without flame arrestors, not specified with flame arrestors. ** Separator cannot be in the same dyke.
T treaters should be at least 5 m (shell to shell) from other treaters.

Note: A) boilers etc. includes steam generating equipment, electric generators and teg units. B) Other sources of ignitable vapours include compressors. C) Flame type equipment includes: treaters, reboilers and line heaters. D) All electrical installations must conform to the Canadian Electrical Code.

Table 9E.2: Wellsite Spacing Requirements

Equipment / Materials	Distancing Requirements	Source of Requirement
Remote BOP controls (Service rig Class A)	Additional set of controls located a minimum of 7 metres from the well.	OGAOM 9.6.5
Remote BOP controls Accumulator (Service rig class B&C)	25 metres from the well, shielded or housed to protect the operator from flow from the well.	OGAOM 9.6.6
Accumulator Remote Controls (Drilling rig)	15 metres from wellhead	OGAOM 8.3.4
BOP hydraulic hoses without fire resistant sheath or not be of steel construction	5 metres from the well for drilling rig	OGAOM 8.3.5
	7 metres from the well for service rig	OGAOM 9.6.4
Earthen pit to store liquid waste	Not located within 100 metres of the natural boundary of a water body, Not located within 200 metres of a water supply well,	DPR 51(3)
Fire Precautions - Flare Stacks	Blackened area beneath a flare stack is 1.5 times the stack height to a minimum of 10 metres in cultivated areas, and: 30 metres in forested areas. Note: Flare blackened area determination must take into consideration the current elevated risks of wildfires due to recent drought conditions. This may increase the flare blackened area requirements.	OGAOM 9.6.15
Fire Precautions – Fuel	Gasoline or liquid fuel, except for fuel in tanks that are connected to operating equipment, must not be stored within 25 metres of a well and drainage must be away from the wellhead.	OGAOM 9.6.15 DPR45(2)
Fire Precautions - smoking	Person carrying out an oil and gas activity must not smoke within 25 metres of any well or facility	DPR 45(4) OGAOM 9.6.15
Fire Prevention – explosives	Explosives of every kind and description are stored only in properly constructed magazines, situated not less than 150 metres from any place where any drilling, production or processing operation is being undertaken.	DPR 47(g) OGAOM 9.6.15
Fire Prevention - flares and incinerators	80 metres from any other public road. 100 metres from any permanent building, installation or works that is not associated with an oil and gas activity. 100 metres from any place of public concourse.	DPR 47 OGAOM 9.6.15
Flare tank	Have a minimum 10 metre setback from vegetation or other potential fire hazards.	OGAOM 8.3.5
Lease Maintenance	An area of 10 metres radius around the wellhead must be maintained to prevent brush from growing and causing a fire hazard.	OGAOM 9.3.2
Ram type blowout preventers (Drilling Rig)	Controls must be attached and be at least 5 metres from the well.	OGAOM 8.3.4
Petroleum storage tanks and production equipment	80 metres from any other public road, 100 metres from any permanent building, installation or works that is not associated with an oil and gas activity, and 100 metres from any place of public concourse.	DPR 48
Wellhead to Roads (surveyed or road allowances	40 metres	DPR 5(2)
Wellhead to Wellsite trailer	25 metres	Treated as flammable equipment.
Wellhead to Surface Improvement	100 metres	DPR 5(2)
Wellhead to permanent building Wellhead to military installation	100 metres	DPR5(2)
Wellhead to Public facility Wellhead to Railway-right of way	40 metres	DPR5(2)

Wellhead to Pipeline-right of way		
Above-ground saline storage	The structure is not located within 100 metres of the natural boundary of a water body unless the structure is on a permitted well location.	DPR 51(6)

Flare Stacks

A sufficient area beneath and around flare stacks must be cleared of flammable materials and vegetation.

The recommended blackened area beneath a flare stack is 1.5 times the stack height to a minimum of 10 metres in cultivated areas and 30 metres in forested areas, unless conditions support a lesser distance. Note: Flare blackened are determination must take into consideration the current elevated risks of wildfires due to recent drought conditions. This may increase the flare blackened area requirements.

The Regulator recognizes that a lesser area may be justified depending on the circumstances. It is the responsibility of the permit holder to maintain a sufficient area, given the location and the conditions under which flaring will or may occur.

Flare blackened areas must be maintained within permissioned land area. If new area is required to accommodate the blackened area, an amendment to the well/facility area is required.

Explosives

Explosives must be stored in properly constructed magazines and be located a minimum of 150 metres from any well servicing operation.

9.6.16 Inter-Wellbore Communications

Inter-wellbore communication may occur as a fluid and/or pressure communication event at an offset well resulting from fracture stimulation on a subject well. Communication levels include:

- Incident level communication is a communication resulting in a spill, equipment overpressure, equipment damage, injury or a drilling kick.
- Event level communication is any communications not at the incident level.

Permit holders are obligated to manage the risks of inter-wellbore communication between the subject well and an offset well. Document hydraulic fracturing programs and include the following elements:

- Identify all offset wells that could be affected.
- Conduct a risk assessment of the identified offset wells.
- Develop a well control plan for all offset wells that are at risk.
- Modify the hydraulic fracturing program if risks cannot be mitigated.

Subject well permit holder must notify a permit holder of an at-risk offset well of a planned hydraulic fracturing program and make all reasonable efforts to develop a mutually-agreeable well control plan. The subject well permit holder must maintain a copy of the at-risk well control plan for the duration of hydraulic fracturing operations.

The permit holder of an at-risk offset well, upon receiving notification of a planned hydraulic fracturing program, is expected to engage and work cooperatively with the subject well permit holder in development of well control plans.

Report all fracture communication events using the Regulator's Inter-Wellbore Communication Report Form (located on the Regulator's Wells Documentation web page) and follow the ESC's IRP Volume #24: Fracture Stimulation (Draft) for specific methodology and procedures regarding the inter-wellbore communication management process.

All fracture communication incidents must also be reported in accordance with the Regulator's Incident Reporting Instructions and Guidelines.

9.7 Environmental Considerations

The environmental considerations section outlines and explains the regulatory requirements for testing, repairing and reporting environmental impacts: hydraulic fracturing, seismic activity, surface case venting flows, gas migration, casing leaks and failures, noise, fluid storage and spills.

In addition, refer to the Flaring and Venting Reduction Guideline for detailed guidance.

9.7.1 Fracture Fluid Disclosure

Section 37 of the Drilling and Production Regulation states that permit holders carrying out hydraulic fracturing operations must maintain detailed records of fracture fluid composition, and submit records to the Regulator within 30 days of well completion. Refer to Section 9.8.3 of this document for further information. Hydraulic fracture fluid reports are submitted to the Regulator via Kermit.

CAPP's Guiding Principles for Hydraulic Fracturing outlines a responsible approach to hydraulic fracturing, including the selection and development of fracturing fluid additives with the least environmental risk. To further this initiative, the Regulator supported the BC Oil and Gas Research and Innovation Society (OGRIS) to fund a University of British Columbia (Okanagan) project identifying alternative methods of assessing the "greenness" of hydraulic fracturing additives. A link to the final report can be found at: http://www.bcogris.ca/sites/default/files/ei-2017-01-final-report-ubco-ver-1a.pdf.

The Regulator expects permit holders to select the least hazardous additives that achieve similar results.

9.7.2 Seismic Activity

Infrastructure must be built to withstand the effects of the elements or seismic disturbance. Requirements to monitor, report and address seismic disturbances must be followed.

Permit conditions may be employed to regulate induced seismicity. During fracturing operations, permit holders must contact the Regulator Emergency Contact at 1-800-663-3456 in the following seismic event:

- Recorded by the permit holder or any source available to the permit holder as being magnitude 4.0 or greater and within a three kilometre radius of the drilling pad.
- Felt on the surface within a three kilometre radius of the drilling pad.

In the event of a well pad is responsible for a seismic event, the permit holder will suspend fracturing operations on the well immediately. The seismic event may be identified by either the permit holder or the Regulator as described above.

Suspended fracturing operations may be continued if: Permit holder presents to the Regulator a plan for mitigation aimed at reducing the seismicity or eliminating well operations related to the induced seismicity.

- Regulator is satisfied with the plan.
- Permit holder implements the plan.

The Regulator tracks northeast B.C. seismic events and compares these seismic events alongside the locations of oil and gas permit holders. Further information and recommendations from the Regulator's investigation into seismic activity is detailed in the Investigation of Observed Seismicity in the Montney Basin and the Investigation of Observed Seismicity in the Horn River Basin.

9.7.3 Surface Casing Vent Flow

Permit holders must carry out surface casing vent flow activities, checks and tests, repairs where applicable and as detailed in this section and according to Section 41 of the Drilling and Production Regulation.

Surface Casing Vent Flow (SCVF) means:

- The flow of gas and/or liquid from the surface casing/ casing annulus.

Serious Surface Casing Vent Flow means:

- Vent flows with hydrogen sulphide (H_2S) present.
- Vent flow with a stabilized gas flow rate equal to or greater than 300 cubic metres per day (m^3/d).
- Vent flow with a surface casing vent stabilized shut-in pressure greater than one half the formation leak-off pressure at the surface casing shoe or 11 kPa/m times the surface casing setting depth.
- Hydrocarbon liquid (oil) vent flow.
- Vent flow due to wellhead seal failures or casing failure.
- Water vent flow if the water contains substances that could cause soil or groundwater contamination.
- Vent flow where any usable water zone is not covered by cemented casing.
- Other vent flow constituting a fire, public safety, or environmental hazard.

As per Section 41 (4.01) of the Drilling and Production Regulation, a well permit holder must ensure that emissions of natural gas from a SCV do not exceed 100 m3/d. Permit holders for wells with vent flows that are non-serious but greater than 100m3/d are encouraged to contact the Regulator.

As per Section 41 (4.02) of the Drilling and Production Regulation, beginning on January 1, 2026, a well permit holder must ensure that emissions of natural gas from a SCVF do not exceed 3 m3/d if all of the following conditions are true.

- the surface casing is cemented to the surface;
- the surface casing is set below the base of usable groundwater;
- the stabilized buildup pressure of the surface casing vent does not exceed ½ of the formation leak off pressure at the base of the surface casing.

According to Sections 41 (4.04) and 41 (4.05) of the Drilling and Production Regulation, a well permit holder must notify the BCER through eSubmission of a Notice of Operation at least 7 days before taking action to control these SCVFs, in order to be in compliance with Section 41(4.02). The notification should demonstrate how the conditions listed above are met and identify the actions taken to control the SCVF.

As per Section 41 (4.03) of the Drilling and Production Regulation, Section 41 (4.02) does not apply:

- until 90 days after discovery of the vent flow,
- during testing of a vent flow or during a well operation, or
- until after initial completion of a well unless a well becomes inactive in accordance with Drilling and Production Regulation Section 25 prior to initial completion of the well.

Checking for Surface Casing Vent Flows

In accordance with Section 41 (2) of the Drilling and Production Regulation, a permit holder must check each well for evidence of a surface casing vent flow:

(a) immediately after initial completion or any recompletion of the well,

> Guidance: Wells shall be checked for the presence of a surface casing vent flow no later than 7 days after the final date of a well operation which resulted in the completion of the well, the recompletion of the well, or the stimulation of a formation by hydraulic fracture or acidization.

(b) at the time of rig release,

> Guidance: Wells shall be checked for the presence of a surface casing vent flow no later than 7 days after the release of the drilling rig. In the event a surface casing vent flow is discovered, and a well operation that will result in the completion of the well is to be initiated within 60 days of rig release, the flow rate and buildup pressure tests required under Section 41 (4) of the Regulation may be performed no later than 7 days after the final date of that well operation, provided there is no risk to health, safety or the

environment.

(c) as routine maintenance throughout the life of the well,

Guidance: Wells shall be checked for the presence of a surface casing vent flow at an interval the permit holder deems appropriate to maintain a full and accurate understanding of the well conditions. This may involve annual vent flow checks for new wells, or less frequent checks for older, stable wells.

(d) before suspension of the well,

Guidance: Wells shall be checked for the presence of a surface casing vent flow no earlier than 7 days prior to the commencement of suspension operations. If the suspension of the well requires a service rig, slickline or wireline, the well can be checked for the presence of a surface casing vent flow between the commencement of activities and the release of the service rig, slickline or wireline.

(e) before abandoning the well, and

Guidance: Wells shall be checked for the presence of a surface casing vent flow no earlier than 7 days prior to the commencement of abandonment operations. If surface abandonment is being completed as a separate operation from the downhole abandonment, wells shall also be checked for the presence of a surface casing vent flow prior to final surface abandonment (cut & cap).

(f) before applying for a transfer of the well permit.

Guidance: Wells shall be checked for the presence of a surface casing vent flow no earlier than 2 years prior to the proposed transfer of the well permit. If the well proposed to be transferred has been checked within the last 2 years for a purpose listed above, no additional checking is required.

Note that if a vent flow is discovered under subsections (a), (b), (c), (d) or (f), it is recommended that further testing continue for a minimum 5-year period. This period of continued testing is described below, in the subsection entitled Testing and Reporting Surface Casing Vent Flows.

As per Section 18 (10) and Section 41 (2.1) of the Drilling and Production Regulation, the requirements of the Drilling and Production Regulation Section 18(9a) or Section 41(2) do not apply if all the following conditions are satisfied:

- the surface casing is cemented to the surface;
- the surface casing is set below the base of useable groundwater;

- the buildup pressure of the surface casing vent does not exceed ½ of the formation leak off pressure at the base of the surface casing;
- the well permit holder has control of emission through one of the following:
  - installation of a burst plate on the surface casing vent with a maximum pressure that does not exceed ½ of the formation leak off pressure at the base of the surface casing
  - flaring emissions of natural gas from the surface casing vent in accordance with Drilling and Production Regulation Sections 42 to 44;
  - routing emission of natural gas from the surface casing vent to hydrocarbon conservation equipment

Permit holders are encouraged to check for the presence of, and test, surface casing vent flows only during non-freezing months to ensure that the buildup of ice in the surface casing vent does not influence the results.

Bubble Test Information

A 10-minute bubble test is adequate to test for the presence of a surface casing vent flow. The recommended procedure is as follows:

- Bubble Test Equipment:
  - Container of water (from 500 ml to 1L).
  - Pipe fittings, small hose (minimum 6mm), or other equipment necessary to direct gas flow from vent downward in the water container.
- Bubble Test Procedure:
  - Ensure no gas leaks at fittings and welds.
  - Ensure there is no H_2S present.
  - Ensure all valves in the vent line are open.
  - If necessary, connect test fittings to the vent so gas flow can be directed into the container of water.
  - Immerse vent or hose a maximum of 2.5 cm below the water surface.
  - Observe for 10 minutes. Note any gas flow (for example, bubbles) which must be recorded as a positive vent flow.
  - Record observations.

Visual observation is sufficient to confirm the presence of a liquid SCVF. The presence of H_2S in a SCVF can be confirmed by the use of a personal monitor, onsite H_2S tests, or other methods as appropriate.

Testing and Reporting Surface Casing Vent Flows

Serious surface casing vent flows present a safety or environmental hazard and must be reported to the Regulator immediately.

On discovery of a surface casing vent flow that does not present an immediate safety or environmental hazard, a well permit holder must test the surface casing vent flow rate and buildup pressure, and report the surface casing vent flow test results to the Regulator within 30 days of the discovery of the surface casing vent flow.

Following discovery and initial reporting, permit holders should perform annual surface casing vent flow tests for a minimum of five years. The permit holder may select appropriate yearly testing measures, however, the Regulator may order specific test measures for surface casing vent flows of particular concern.

In the event a significant change to a previously-identified SCVF is observed, permit holders should report their findings to the Regulator. Examples of a significant change are:

(a) from no vent flow to non-serious vent flow or serious vent flow,

(b) from non-serious vent flow to serious vent flow, or vice-versa,

(c) from non-serious vent flow or serious vent flow to no vent flow

The results of SCVF tests required as part of a Regulator inspection must be reported.

The Regulator recommends that permit holders report all surface casing vent flow test results. Non-reported test results must be maintained on file and provided to the Regulator on request.

All reporting of SCVF test results must be done via the Regulator's eSubmission portal.

Measuring Flowrate

Once a positive vent flow is detected, the flow rate and stabilized shut in pressures must be recorded. To measure venting gas volumes, a positive displacement gas meter, turbine meter or an orifice well tester may be used. Equipment selection should be based on previous observations indicating what flow rate and pressure range can be expected. A positive displacement meter will be necessary to measure low volumes accurately. An orifice well tester, with proper orifice plate, may provide satisfactory measurements if the 24 hour shut in pressure is 200 kPa or greater and builds quickly.

Install and use the equipment according to manufacturer's instructions:

- Do not exceed the pressure/volume range of the equipment.
- Ensure there are no leaks.

Measuring Buildup Pressure

While conducting a surface casing buildup pressure test, a pressure relief valve should be installed on the surface casing vent testing assembly. This pressure relief valve should be calibrated to release at a pressure no greater than 11 kPa/m times the surface casing setting depth.

To determine the stabilized surface casing buildup pressure, the following equipment can be used:

- Single pen static pressure recorder with 24-hour chart, or
- Electronic pressure recorder, or
- Deadweight pressure gauge

If it is anticipated that the buildup pressure will exceed the maximum allowable pressure specified above, then a recording device must be used, such as an electronic pressure recorder, in order to capture a record of the rising pressure and the point at which the relief valve opens.

Once the surface casing flow rate test has been completed, a buildup pressure test must be conducted. The recommended buildup pressure test procedure is as follows:

- Install pressure recorder (or deadweight gauge) and pressure relief valve.
- Ensure that there are no leaking fittings, welds or connections.
- Close the surface casing vent test assembly downstream of the pressure recorder and pressure relief valve.
- Monitor the buildup pressure as required until a stabilized maximum pressure is reached, or the pressure relief valve opens.
- If using a deadweight pressure gauge, record the buildup pressure at appropriate intervals until a stabilized pressure is reached or the pressure relief valve opens.
- If a pen pressure recorder is being used, and the pressure does not stabilize within 24 hours, change the chart as required to obtain a full

and complete record of the buildup pressure test.

The buildup pressure has reached a stabilized value if over the last 6 hours of the test, the pressure changes at a rate of less than 2 kPa per hour - 12 kPa or less in a 6 hour period.

9.7.4 Surface Casing Vent Flow Repairs and Production

Non-Serious Repair

Remedial repair may be deferred until well abandonment for non-serious surface casing vent flows.

In an effort to minimize the amount of venting from a non-serious surface casing vent flow, the permit holder may consider the installation of a burst plate or pressure safety valve (PSV). The permit holder must obtain an exemption to Section 18(9)(a) of the Drilling and Production Regulation to allow the installation of a burst plate or pressure safety valve.

Non-serious surface casing vent flows must be repaired at the time of well abandonment.

Repair of a Serious Surface Casing Vent Flow

The permit holder of a well determined to have a serious surface casing vent flow should contact the Regulator as soon as possible to discuss repair or management requirements.

If the permit holder wishes to explore the option of producing the surface casing vent flow, an application must be made to the Drilling and Production Department to obtain an exemption to Section 18(9)(a) of the Drilling and Production Regulation. Requests will be considered if:

- The source depth and formation of origin has been clearly identified.
- The permit holder owns the mineral rights to produce the source formation.
- The cemented portion of the surface casing or the next casing string covers the deepest known usable groundwater.
- The flow has been analyzed and determined to be sweet (0 per cent H_2S).

The Regulator may rescind the approval to produce from the surface casing vent and may require the surface casing vent flow to be repaired at any time if the Regulator determines a safety or environmental hazard exists.

9.7.5 Intermediate Casing Vent Flow

If a well has surface casing, intermediate casing and production casing, there is a possibility of fluid flowing out from the annulus between the intermediate casing and production casing in case that the annulus is open. The flow from the annulus between the intermediate casing and production casing is intermediate casing vent flow (ICVF).

Normally, the intermediate casing vent assembly (ICVA) can be closed because the intermediate casing is often set deep enough, e.g., deeper than 600mKB, as long as the pressure in the annulus between intermediate casing and production casing is not high enough to fracture the formations below the intermediate casing shoe and there is no possibility of interzone communication.

If the pressure in the annulus between intermediate casing and production casing is higher than the fracture pressure of the formations below the intermediate casing shoe, or there is a possibility of interzone communication, the permit holder should fix the problem.

If the intermediate casing is not set deeper than 600mKB and there is a water zone below the intermediate casing shoe, the permit holder should conduct the assessment to identify if the close ICVA may cause groundwater contamination in case that the intermediate casing vent flow does exist. If the assessment shows the possibility of groundwater contamination, the permit holder may need to repair the problem.

Intermediate casing vent flow must be repaired during the abandonment.

In summary, the valve on ICVA can be closed and the ICVA pressure is monitored. If there is no pressure buildup, i.e., no ICVF, the further action is not required. If there is a pressure buildup, i.e., ICVF does exist, a risk assessment is required in order to determine if the valve on ICVA can be kept close or the repair is required.

9.7.6 Gas Migration Reporting, Field Testing and Risk Assessment

Gas Migration Definition and Identification

“Gas migration” means a flow of gas outside of the surface casing of a well.

Gas migration (GM) may be indicated by a variety of symptoms, which may include, but are not limited to:

- bubbles in ponded surface water surrounding a wellhead,
- stressed vegetation,
- the presence of odors or combustible gas not attributable to another source.

The Regulator advises, and may require, that field measurements (as described in sections below) be conducted to investigate for gas migration that has not been observed or detected at surface, under the following circumstances and when safe to do so:

- Following a loss of well control incident.
- For cases where sustained the annular pressure between surface casing and next casing exceeds 9.8kPa/m x the depth of the surface casing (in metres).
- If there is a known well integrity issue with the potential to cause gas migration.
- Prior to abandonment, where a combination of factors suggest gas migration is more likely to occur.

Gas Migration Notification Requirements

In accordance with Section 41 (4.1)(a) of the Drilling and Production Regulation (DPR), on discovery of an occurrence of gas migration, the permit holder must "immediately notify the Regulator of the gas migration".

The permit holder must assess conditions at the well and at areas surrounding the well to determine whether the GM is considered "serious" or "non-serious" and follow notification procedures below.

Serious Gas Migration

The following cases of GM are considered "serious":

- involve gas containing H_2S; or
- could generate a potential fire or explosion hazard on or off lease; or
- indicate an immediate safety issue or may cause off-lease environmental damage such as groundwater contamination.

Serious cases of GM must be reported to the Regulator as follows.

1. Check the Incident Classification Matrix and make a decision if the Emergency Management B.C. line at 1-800-663-3456 must be called.
2. Contact the Regulator's Drilling and Production staff as soon as possible.
3. Submission of a completed initial gas migration notification within 24 hours of discovery via the eSubmission portal.

For all cases of serious gas migration, operators are, additionally, required to take immediate emergency response action, where warranted, for the protection of public safety and the environment as required under the relevant legislation.

Gas Migration Evaluation and Risk Assessment Requirements – Gas Migration Field Testing

Field testing is required to confirm the presence or absence of GM, or characterize the extent of GM. Field testing must be conducted and reported as part of the required Risk Assessment pursuant to DPR Section 41(4.1)(b)(c). Field testing should be repeated at an appropriate frequency to ensure the risk assessment (as described below) remains valid over time.

GM field testing equipment should be calibrated and be capable of detecting hydrocarbons at one ppm.

GM field testing methods are described below. For a given case of GM, field testing method(s) should be selected to provide as much data as possible regarding the degree, areal extent, source, and risk of the GM.

Please Note:

The Commission recognizes that there is temporal and spatial variability in surface gas efflux detection and concentration measurements resulting from gas migration. Influencing factors can include temperature, heavy rain or snow cover, wind, and barometric pressure. As such, more than one testing event and method may be necessary to provide confidence in test results. Confirmation of field testing results, positive or negative, may be required by the Commission.

GM field testing methods may include:

Site Observations: Document all site observations of relevance to the GM including but not limited to:

- the locations and degree of bubbling in standing water proximal to the wellhead and across the lease area, if present;

- areas of dead or stressed vegetation proximal to the wellhead; and
- any evidence of liquid hydrocarbon around the wellhead (e.g., a visible sheen).

H_2S Detection: Conduct H_2S test on the migrating gas using a handheld H_2S detector or personal monitor to confirm the presence/absence of H_2S. If SCVF is also present at the well, SCVF gas should also be tested for H_2S using this method.

Ground Surface Methane Detection: Ground Surface Methane Detection means field measurements at the ground surface using a properly calibrated methane detector and the following procedures:

- Prior to initiating testing near the wellhead, background methane levels should be tested and documented by off lease measurements.
- If there is no water around the well, move the methane detector at ground surface all over the area including the area around the well to detect the leaking points. The methane detector should be positioned for measurements as close to the ground surface as possible.
- If methane is present on ground surface, the following information should be included in the field test report:
    - the gas leaking locations at ground surface diagram as shown in Figure 9.1, and
    - the highest methane concentrations at each gas leaking locations and the radius for the affected area for each leaking location in a table.

Note: Methane concentrations for all leaking points (as ppm or if concentrations are above 10,000 ppm, in per cent) should be recorded in tabular form with location coordinates relative to the wellhead, and/or mapped in plan view for all leaking points.

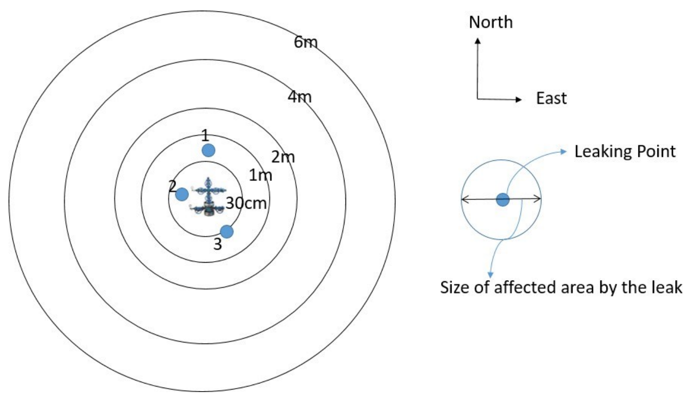
- Collect the gas sample for lab analysis if this was not done before or there is a significant change on the GM.

Gas samples may be collected of the migrating gas (and from the surface casing vent if SCVF is present) for gas compositional analysis and carbon isotopic analysis to assist in identifying the cause and source of GM (required in DPR 41(4.1)(b)). Isotopic analysis may indicate whether the gas is biogenic or thermogenic and/or the possible source formation.

Note: Gas samples shall be collected using environmental sampling protocols that yield a sample as representative as possible of the migrating gas.

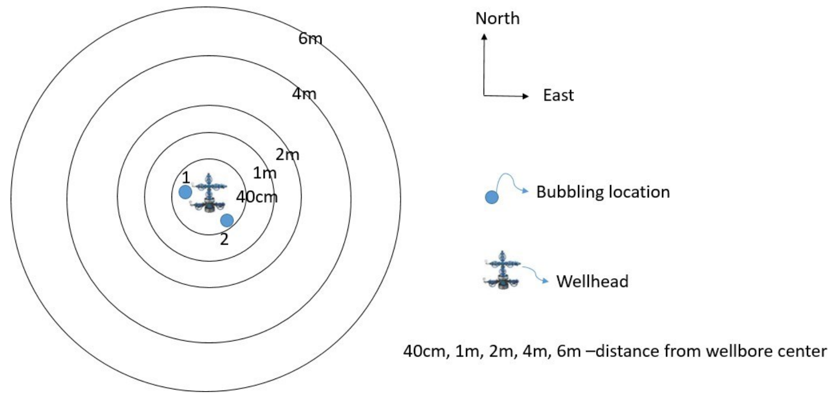
- In case that methane is present at a 6 m distance from the wellbore center, the test must be extended by appropriate distance intervals over an area sufficient to delineate the extent of gas at ground surface.
- In case that the well is located in an area covered by water,
  - record bubbling locations in a diagram as shown in Figure 9.2, and
  - record estimated bubbling frequency and/or highest methane concentration for each bubbling location if possible.

Figure 9.1 Ground Surface Methane Detection report at WA#WXYZ



Leaking Point #	Highest CH4	Size of affected area by the leak (cm)
1	1%	10
2	8%	50
3	500ppm	5
Background	2-4ppm	
Note		The well has a surface casing vent flow of gas. The outlet of surface casing vent flow assembly is only 50cm from the leaking Point 3 so that the highest CH4 at Point #3 may be affected by SCVF.

Figure 9.2 Ground Surface Methane Detection report at WA# ABCDE



Leaking Point #	Highest CH4	# of bubbles per minute
1	5000ppm	10
2	8%	too many to count
Background	0	
Note		There is a cellar containing water around wellhead. The diameter of the cellar is around 40cm. Two bubbling locations in the cellar. No leaking location was found outside the cellar.

Shallow Gas Survey: The Regulator requires testing to be carried out to identify the extent of gas migration in the shallow subsurface by completion of a shallow gas survey extending radially around the wellhead as follows.

Required Equipment:

- Bar or auger (64 mm or less in diameter) capable of penetrating a minimum of 50 cm.
- Equipment or material to seal the hole at surface while soil gases are being evacuated from the soils through the instrument.

Preparation for testing:

Testing must be done in frost free months only and periods immediately after rainfall should be avoided. If contaminated soils are suspected across the survey area, the soil should be excavated and removed prior to testing. Instrument calibration must be performed.

Sampling points:

Two sampling points must be located within 30 cm of the wellbore on opposite sides. Additional sampling points must be placed at two metre intervals outward from the wellbore, every 90 degrees (centered at the wellbore), to a minimum radius of 6 metre.

If detectable gas is identified at a 6 metre distance from the wellhead, the shallow gas survey must be extended by appropriate distance intervals over an area sufficient to delineate the extent of gas in the shallow subsurface.

In addition to the above sampling locations, at least four additional point measurements should be made outside the four sides of a compacted well pad if the well pad could be considered to be a potential barrier to the efflux of gas at the ground surface.

Test Procedure:

- Insert auger or make a bar hole a minimum of 50 cm deep.
- Isolate the hole from atmospheric contaminants.
- Obtain sample a minimum of 30 cm into the hole, maintaining a seal at surface to prevent atmospheric gas and soil gas mixing.
- Withdraw soil gas sample. The volume, rate, etc., will depend on the instrumentation being used. Ensure that a sufficient sample is removed to purge lines and instrumentation.
- Purge instrument and lines prior to taking next measurement.
- Document preparation, procedures, and results.

Down Hole Diagnostic Testing: Downhole diagnostic testing, such as noise-temperature logs or cement bond logs, is not normally required as part of an initial field test however, may be performed if the permit holder deems it necessary. If the information is available, it should be considered as part of further assessments.

Once all required field testing has been completed, as described above, the GM field test report and the lab analysis report indicating possible source of the migrating gas should be submitted as attachments to a Gas Migration submission via the eSubmission portal. The field test results must be incorporated with a desktop review into a complete Gas Migration Risk Assessment.

Section 41(4.1) of the Drilling and Production Regulation requires the submission of an assessment on discovery of a case of gas migration. Permit holders should monitor the gas migration periodically following the initial risk assessment to ensure the risk assessment remains valid. Additional monitoring or testing requirements may be required by the Regulator.

Gas Migration Evaluation and Risk Assessment Requirements – Desktop Review

A risk assessment shall be conducted (DPR Section 41 (4.1) (b)), and a risk assessment report must be submitted (DPR Section 41(4.1)(c)) within 90 days of the initial discovery of GM, unless an alternate submission schedule is authorized by the Regulator, for example to allow testing during frost-free conditions. Based on review of the risk assessment report, the Regulator may specify requirements for further investigation, monitoring, mitigation, and/or reporting.

The risk assessment and risk assessment report must be conducted/prepared by qualified person(s) with appropriate experience and expertise, and in accordance with all applicable Professional Designation requirements and standards.

The assessment and report shall include the following components unless previously submitted to the Regulator.

- Documentation of Well and Site Information, including:
    - A summary of well construction details and relevant well history.
    - Description of site geographic location, site facilities and structures, topographic information and features, land surface conditions (vegetation, land clearing), and surrounding land use (including protected areas and parkland).
    - Supporting maps and site plans.
- Documentation of all field testing conducted (described above) including all procedures, results, and laboratory documentation.
- An assessment of the source and cause of gas migration (DPR 41(4.1)(b)), based on well information and field testing results.
- Identification of potential human and environmental receptors, including:
    - Documentation of desktop information for a 2 km radius surrounding the well related to proximity to potential human or environmental receptors including: information for water supply wells, mapped aquifers, mapped capture zones (i.e., water well source areas), provincial observation wells, residential areas, public and protected areas, surface water bodies,

Provincial water authorizations (e.g., water use approvals or licenses), or other relevant information. The Regulator's Groundwater Review Assistant (GWRA) should be used to compile desktop information and a copy of the GWRA output report shall be included with the Risk Assessment Report. Additional land use information may be compiled using iMapBC, Google Earth, and/or review of aerial photographs or imagery where available.

  - Documentation of a field reconnaissance, conducted where practicable, to verify the desktop information.
  - Supporting maps and figures as appropriate.

- Assessment of Risk and Proposed Mitigation and Management Measures, including:
  - Tabulated risks based on the BCER Risk Assessment Framework for Wellsites with Gas Migration (see Table 9F), which includes identification of hazards and assessment of potential safety, health, and environmental risks based on the compiled well, desktop, and field investigation information. A fillable form version of Table 9F can be found on the Regulator's website.
  - Proposed mitigation and management measures for identified risks. These shall include, where appropriate, gas migration repair measures, site restoration measures, well abandonment plan, groundwater and/or soil quality assessment (installation of monitoring wells), long term monitoring of gas flow and extent of gas migration, air quality monitoring, enhancements to site security (e.g., fencing), any or other appropriate measures.

Table 9F: BCER Risk Assessment Framework for Wellsites with Gas Migration

[1]Risk rating must be supported by information documented in or appended to the Risk Assessment Report.

Risk rating may be updated following implementation of management, monitoring, mitigation, or further investigation.

Well Authorization Number:________________________ **Risk Assessment Report Date:** _______________

Risk Category	Potential Hazard Description and Risk Rationale	Risk Rating Guidance			[1]Risk Rating and Proposed Management, Monitoring, Mitigation or Further Investigation
		Low	Moderate	High	
General Public Safety	Identify potential public safety hazards within the lease area (site), including general hazards associated with Infrastructure and potential confined space Hazards, with consideration of the potential for unintentional or Intentional public access.	No potential hazards identified	One or more potential site hazards identified **AND** low potential for public access to site	One or more potential site hazards identified **AND** reasonable potential for public access to site	
Fire or Explosion	Identify potential hazards based on shallow gas survey results with consideration of potential ignition sources.	Gas Concentrations < 100% LEL **OR** >100% LEL and access is restricted	Gas Concentrations > 100% LEL **AND** low potential for ignition source	Gas Concentrations > 100% LEL **AND** potential for ignition source	
Air Quality	Identify potential concerns related to air quality due to odour and H_2S based on field observations or gas analysis, with consideration of potential human receptors.	No odour observed **AND** gas does not contain H_2S	Odour is apparent **AND** members of the public are highly unlikely to be within 100 m of the site	Gas contains H_2S **OR** odour is apparent and potential exists for members of the public to be within 100 m of the site	
Groundwater	Identify potential hazards to groundwater quality based gas analysis and the shallow gas survey results, with consideration of the potential for groundwater to reach Potential human receptors.	Gas is not thermogenic **AND** gas migration does not extend off site	Gas is thermogenic **OR** gas is not thermogenic and shallow gas extends off site	Gas is thermogenic **AND** water wells, water intakes, or licensed springs are within 600 m of the well	
Surface Water and Riparian Areas	Identify potential hazards based on the gas analysis with consideration of the potential for groundwater discharge to surface water bodies/riparian areas.	Gas is not thermogenic **OR** gas is thermogenic with low potential for groundwater discharge to a riparian area or surface water body	Gas is thermogenic **AND** there is potential for groundwater discharge to a riparian area or surface water body	Gas migration flow rates could result in the accumulation of gas at surface water bodies or riparian areas on or off site	

A fillable version of Table 9-F is available on the Regulator's website

All submissions made to the Regulator in support of an application or a regulatory requirement that include work relating to the practice of professional engineering or professional geoscience are expected to accord with the Professional Governance Act, [SBC 2018], c. 47 and the Bylaws of Engineers and Geoscientists British Columbia (EGBC). This includes any requirements relating to authentication of documents.

Gas Migration Mitigation and Repair Requirements

Serious Gas Migration: For cases of "serious" gas migration, the operator must take steps to eliminate the hazard immediately and repair the GM as soon as possible. Notification to the Regulator of anticipated repair work must be completed via a Notice of Operations submitted via the Regulator's eSubmission porta. Specific requirements may be subject to review by the Regulator's Drilling and Production Engineering team.

Non-serious Gas Migration: For cases of "non-serious" gas migration, the operator may, subject to the completion and submission of a Risk Assessment under DPR Section 41(4.1)(b) and (c), delay repair of the GM until the time of abandonment.

9.7.7 Casing Leaks and Failures

A permit holder must notify the Regulator of any casing leak or casing failure as soon as possible. The leak or failure must be repaired within a reasonable time frame, giving consideration to the accessibility of the site and the seriousness of the leak or failure.

9.7.8 Noise

Section 40 of the Drilling & Production Regulation states:

- A permit holder must ensure operations at a well or facility for which the permit holder is responsible does not cause excessive noise.

Review Section 40 of the DPR and the Regulator's British Columbia Noise Control Best Practices Guideline for an understanding of noise levels, requirements and suggested best practice standards. In addition, work with area residents to minimize noise impacts when undertaking construction, drilling, completions, and operations activities near populated areas.

9.7.9 Fluid Storage at Well Sites

Secondary containment of tanks associated with completions operations is generally not required. For extended, unmanned flowback operations requiring a facility permit, secondary containment in accordance with the National Fire Protection Agency's Flammable and Combustible Liquids Code (NFPA 30) is required.

The Regulator's Management of Saline Fluid for Hydraulic Fracturing Guideline details the requirements and expectations for siting, design, construction, operation, and decommissioning of lined containment systems used for the storage of saline fluids.

The Management of Saline Fluid for Hydraulic Fracturing Guideline provides guidance for permit holders to demonstrate ongoing compliance with ERAA and EMA, and the regulations with respect to the storage of saline fluids.

9.8 Completion / Workover Reporting

A report must be submitted to the Regulator for each completion or workover operation occurring on a well, in accordance with Section 36 of the Drilling and Production Regulation, except in the case of 'maintenance' operations; refer to The Notice of Operation and Completion / Workover Report Reference Guide. Reports must be in chronological format and detail all significant operations, treatments and resulting well behavior and include a downhole schematic that illustrates the configuration of the well at the end of the operation. Reports are submitted by reconciling a report with the corresponding Notice of Operation in eSubmission.

Please Note:

The submission of a Completion / Workover Report does not result in the creation of a Completion Event in the Commission's system or a corresponding Well Event in Petrinex. Completion Events are reported in eSubmission and instructions on this process are found in Section 2.4 of the eSubmission User Guide.

9.8.1 Report Content

A Completion/Workover report submission is a single PDF file comprised of the following:

- The Completion/Workover Report form
- A chronological summary
- A wellbore schematic, in colour
- Detailed daily reports
- Supplementary Information (including pump charts, treatment reports and photos)

The report must be presented in chronological format. The Completion/Workover Form must be the first page of the PDF.

Completion/Workover Report Form

A copy of the Completion/Workover Report Form is available for download here. All applicable sections of the form must be completed. Electronic signatures are acceptable.

Chronological Summary

The chronological summary is a high level, succinct, summary of all major events occurring during the report period, presented by date. Major events include, but are not limited to, perforations, fracturing, acid treatments, and installation and/or modification of downhole equipment.

Downhole Schematic

The wellbore schematic must illustrate the well as of the end of the report and include the depths of all equipment and intervals perforated and/or hydraulically fractured. Incomplete and/or unlabeled schematics will be considered incomplete and a revised submission will be required.

The following list provides some examples of information expected on a schematic:

- Perforations
- Hydraulic fractures

- Remedial work (cement squeezes, casing patches, etc)
- Casing string(s) and cement
- Bottom hole assemblies and tubing strings
- Bridge plugs, packers, cement retainers, cement
- Fish

Daily Reports

A daily report should be included for each day activity took place during the operation. Each daily report must be labelled with the date, WA number and well name and must detail all significant well operations and treatments and the resulting well behavior. Examples of details to be provided include, but are not limited to:

- Pumping pressures, rates, and volumes
- Set depth of packers, bridge plugs, etc.
- Depth/interval of perforations, hydraulic fractures
- Acid types and concentrations

Supplementary Information

Documents such as fracture treatment summaries and pump charts; which support the completion/workover operations data, must be included in the submission. Abandonment reports may require photographs and copies of invoices or welder's tickets, as noted in Section 9.5.

9.8.2 Report Submission

Completion/Workover Reports are submitted in eSubmission. Users must select a Notice of Operation to reconcile the report against. Instructions for submission are in Section 4.9 of the eSubmission User Guide.

Completion/Workover Operations must be submitted within 30 days of the end of the completion and/or workover operations. For initial completions, a prolonged flow-back operation should not delay the submission of the completion/workover report. In cases where flow-back exceeds a period of two weeks, the report should conclude at the two week flow-back mark. An additional report may be required if additional downhole equipment, such as tubing, is installed after this time frame.

Please Note:

Clean up flow requires the submission of a Well Flow Test (PRD) submission. Please refer to the Well Testing & Reporting Requirements Guide for further information.

9.8.3 Hydraulic Fracturing Submissions

When hydraulic fracturing occurs during a completion or workover operation, the complimentary Hydraulic Fracture Data and Fracture Fluid Disclosure Submissions must be made. These are two distinct but complimentary submissions reviewed in conjunction with the Completion/Workover Report (Table 1).

The information reported in the Hydraulic Fracture Data and the Fracture Fluid Disclosure Submissions must be consistent with what is included in the Completion/Workover Report. Discrepancies between submissions may result in the submission(s) being rejected.

Table 1 Completion/Workover and Hydraulic Fracture Reporting Requirements

Submission	Submission Format	Where to Submit	Reporting Timeline
Completion/Workover	PDF	eSubmission	Within 30 days of the end of Completion/Workover Operations
Hydraulic Fracture Data	CSV	eSubmission	Within 30 days of the last hydraulic fracture
Fracture Fluid Disclosure	CSV	Kermit	Within 30 days of the last hydraulic fracture

Hydraulic Fracture Data Submission

The hydraulic fracture data submission is comprised of a FRAC .csv file and, where applicable, a PERF .csv file. The submission is made in eSubmission and must be received within 30 days of the conclusion of hydraulic fracture operations (not including flow back).

Please refer to the Hydraulic Fracture Data – CSV Requirements Guide and section 4.8 of the eSubmission User Guide for further information.

Fracture Fluid Disclosure Submission

The fracture fluid report submission is a .csv file submission disclosing the fracture fluid ingredients. The submission is made in Kermit and is due within 30 days of the conclusion of hydraulic fracture operations (not including flow back).

Please refer to the Fracture Fluid Report Upload Manual for further information.