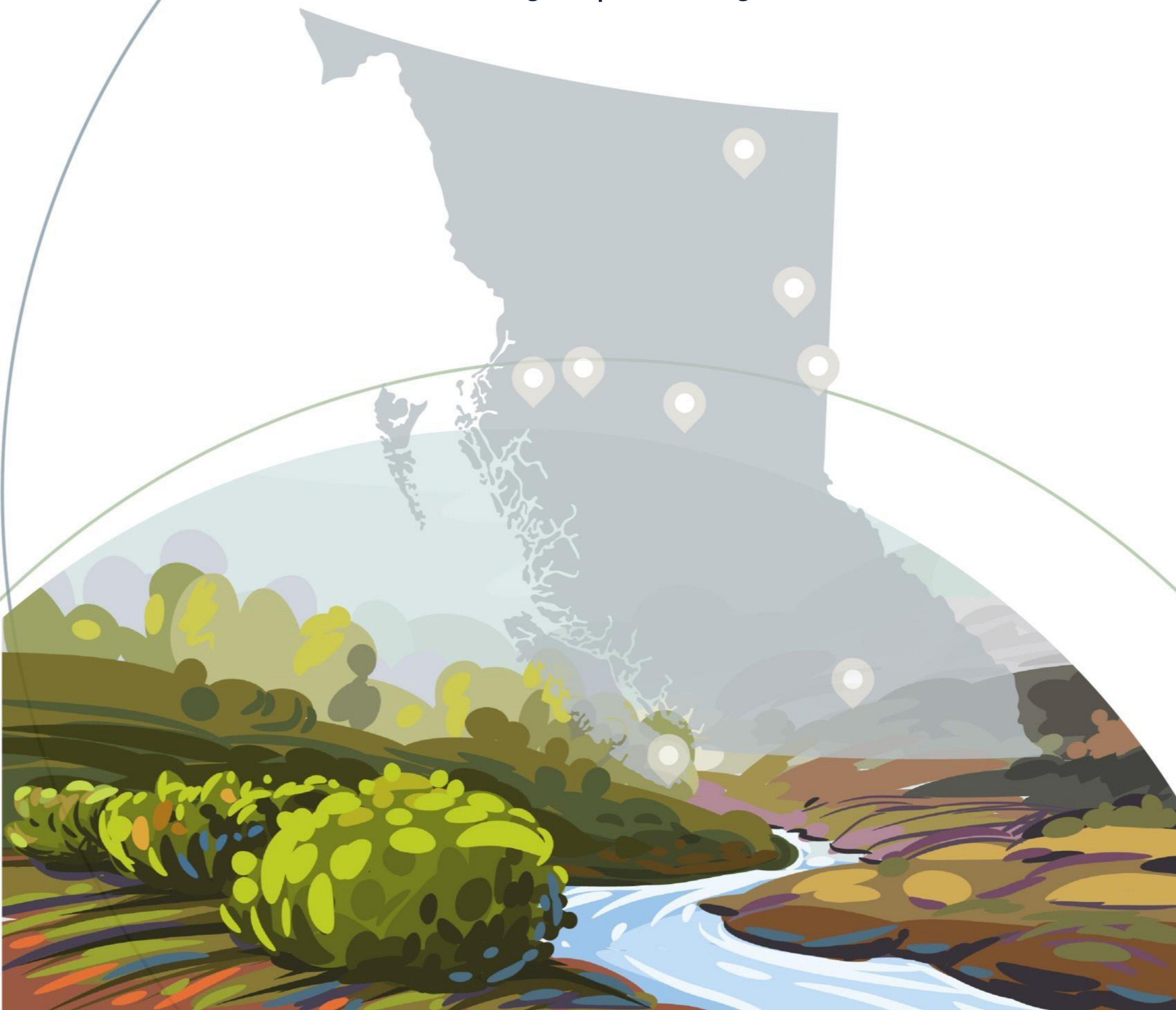
Oil and Gas Activity Operations Manual

BC Oil & Gas COMMISSION

VERSION 1.38: September 2023



About the Commission

The BC Oil and Gas Commission (Commission) is the single-window regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Commission's core roles include reviewing and assessing applications for industry activity, consulting with First Nations, ensuring industry complies with provincial legislation and cooperating with partner agencies. The public interest is protected by ensuring public safety, protecting the environment, conserving petroleum resources and ensuring equitable participation in production.

VISION

Safe and responsible energy resource development for British Columbia.

MISSION

We provide British Columbia with regulatory excellence in responsible energy resource development by protecting public safety, safeguarding the environment and respecting those individuals and communities who are affected.

VALUES

Transparency

Is our commitment to be open and provide clear information on decisions, operations and actions.

Innovation

Is our commitment to learn, adapt, act and grow.

Integrity

Is our commitment to the principles or fairness, trust and accountability.

Respect

Is our commitment to listen, accept and value diverse perspectives.

Responsiveness

Is our commitment to listening and timely and meaningful action.

Additional Guidance

As with all Commission documents, this manual does not take the place of applicable legislation. Readers are encouraged to become familiar with the acts and regulations and seek direction from Commission staff for clarification. Some activities may require additional requirements and approvals from other regulators or create obligations under other statutes. It is the applicant and permit holder's responsibility to know and uphold all legal obligations and responsibilities.

Throughout the manual there are references to guides, forms, tables and definitions to assist in creating and submitting all required information. Additional resources include:

- Glossary and acronym listing on the Commission website.
- Documentation and guidelines on the Commission website.
- Frequently asked questions on the Commission website.
- Advisories, bulletins, reports and directives on the Commission website.
- Regulations and Acts listed on the Commission website.

Oil and Gas Operations Manual

Written by the Commission, the Oil and Gas Operations Manual is a collection of operational requirements for oil and gas permit holders. Each oil and gas activity has regulatory and guidance requirements for construction, operation, deactivation and reclamation. This manual is intended for permit holders of oil and gas and associated activities and provides a reference to Commission requirements with links and suggestions on finding other sources of information.

Table of Contents

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.

Manual Revisions

The Commission is committed to the continuous improvement of its documentation. Revisions to the documentation are highlighted in this section and are posted to the Documentation Section of the Commission's website. Stakeholders are invited to provide input or feedback on Commission documentation to OGC.Systems@bcogc.ca or submit feedback using the feedback form.

Version Number	Posted Date	Effective Date	Chapter Section	Summary of Revision(s)
1.38	September 1, 2023	September 1, 2023	1.3.1	Updated the Extensions section. Changed the submission requirement timeline from 30 days to three months prior to the scheduled expiration.
			11.5.10	Updated to provide clarification on pipeline amendment and notification process.
			Appendix I and J	Updated Appendices to correct numbering as follows: Appendix J changed to Appendix I: Sour Well Information Form Appendix I changed to Appendix J: Benzene Emissions from Glycol Dehydrators

Chapter 1 Overview of Oil and Gas Regulations and Permit Management

1. Overview of Oil and Gas Regulations and Permit Management

Companies looking to explore, develop, produce, and market oil and gas resources in British Columbia must apply to the BC Oil and Gas Commission (Commission) for activity permit(s). The Commission's role in permitting oil and gas activities is defined by the Oil and Gas Activities Act (OGAA).

The Commission operates within a legal framework embodied in the collection of acts, regulations, standards, practice requirements and management plans governing the mandate of the Commission and provides a single-window model for oil and gas and associated activity operating permits.

Operators apply to the Commission, and the Commission reviews, assesses and makes decisions on these applications. This consolidated single-window authority provides not only a one-stop place for all oil and gas and associated activity requirements, but a consistent application, decision, regulatory and compliance authority. Stakeholders work with one agency; therefore serving the public interest by having an all-encompassing review process for oil and gas activities. In addition, operators are expected to abide by all applicable local by-laws, provincial and federal legislations.

In its day to day operations, the Commission is focused on coordinated, responsive and responsible decision-making. Decisions are made while protecting public safety, respecting those affected by oil and gas activities, conserving the environment, and facilitating equitable participation in production.

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Please Note:

The Oil and Gas Activities Act defines both oil and gas activity and related activities and the Commission adheres to these definitions. The Commission's glossary and acronym listing is an extension of this manual and defines terms used throughout the oil and gas activity. Applicants and permit holders should refer to the glossary to understand the exact definition of terminology as it may differ from other regulatory bodies. Due diligence is required to ensure proper understanding of terms, acronyms and legislation.

1.1 Commission's Permitting Authorities

The Commission's specific permitting authority is defined in the Oil and Gas Activities Act (OGAA). In order to effectively function as a single-window regulator for oil and gas in British Columbia, delegation agreements are in place to allow the Commission to make decisions on certain oil and gas uses within the parameters outlined in those agreements. In addition, certain authorizations granted through specific Acts provide the Commission permitting powers under specified enactments.

Permits and authorizations granted by the Commission include:

- Oil and gas activity permits under the Oil and Gas Activities Act, including well, pipeline, facilities, road and geophysical permits.
- Associated oil and gas activity authorizations under the Petroleum and Natural Gas and Land Act, including activities such as borrow pits, temporary work spaces and camp sites.
- Authorizations under the Water Sustainability Act, including authorizations for changes in and about a stream, short-term water use and water licences.
- Non-farm use of lands included in the Agriculture Land Reserve (ALR), under delegated authority under the Agriculture Land Commission Act.
- Master licences to cut and cutting permits under the Forest Act.
- Archaeology-related permissions under the Heritage Conservation Act.
- Specific provincial authorizations related to pipelines subject to the National Energy Board Act.

The Commission provides regulatory oversight at every stage of oil and gas development, working with a broad range of stakeholders. Commission staff have the legislative authority to make decisions on proposed oil and gas activities. In addition, the Commission:

- Tracks permit holder compliance.
- Reviews operational submissions.
- Provides guidance and processes for operators to submit applications and operational requirements.
- Conducts inspections and responds to incidents.
- Takes compliance and enforcement action when needed.

Other Regulatory and Technical Considerations

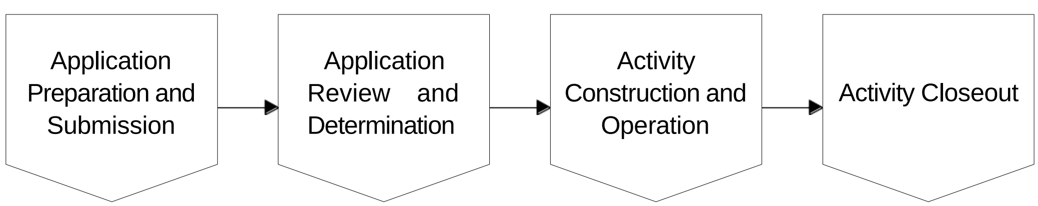
In addition to the regulatory and technical considerations outlined in this manual, applicants and permit holders should be familiar and understand other provincial and federal regulations, local authority requirements, industry recommended practices (IRP), Canadian Standards Association, labour board laws, and workers compensation rules in order to operate in British Columbia.

All submissions made to the Commission 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

1.2 Oil and Gas Activity Regulatory Life Cycle

The regulatory life cycle of an oil and gas activity is the requirements and steps involved in permit application preparation, application review and determination, activity construction and operations and activity close-out as shown in Figure 1-A.

Figure 1-A Oil and Gas Regulatory Life Cycle



Companies must adhere to the pre-application and application requirements as outlined in the Commission's [Oil and Gas Activity Application Manual](). Once pre-application requirements are complete, companies prepare and compile the relevant information for submission to the

Commission's Application Management System (AMS). Following application submission, the Commission conducts a comprehensive technical review of the application based on the characteristics, location and circumstances of the activity.

This manual focuses on the requirements for the construction and operation stages and requirements of the oil and gas and associated activity permits. Activity close out procedures where permitted oil and gas activities are permanently discontinued, equipment is removed and land is restored, are touched on briefly in this manual and in greater scope in the Commission's Certificate of Restoration Application Manual and Environmental Protection and Management Guideline.

Please Note:

Throughout this manual, the term oil and gas activities often refers to both oil and gas and oil and gas associated activities as defined in the Commission's glossary.

1.3 Permit Management

Companies are issued oil and gas permits from the Commission to construct and operate oil and gas and associated activities.

Permit Defined

A permit, as defined by the Oil and Gas Activities Act means:

- A permit issued under Section 25 and includes any conditions imposed on a permit.

Permit Holder Defined

A permit holder, as defined by the Oil and Gas Activities Act means:

- A person who holds a permit.
- A person, if any, who is the holder of a location with respect to that permit.

Permits are only granted to the operator and/or company from the original application. All those working for the permit holder must meet permit requirements.

Permits must be in hand before conducting any activity. Permits may have timelines and/or conditions attached specifying what activities the permit holder may carry out, including, but not limited to, authorizations under the Land Act, Forest Act and Water Sustainability Act. Permit holders must understand the operational guidance and requirements for each activity and reporting requirements throughout the life cycle of the oil and gas and associated activity.

Permits issued over private land are subject to a land owner agreement. If an agreement with the land owner cannot be made, the applicant or land owner may apply to the Surface Rights Board for assistance.

Once a permit is issued, companies should continue to take into consideration the entire life cycle of the project and minimize the environmental impacts of the proposed project. Permit holders are responsible for keeping current with legislation, regulatory updates and documentation in order to properly and safely pursue oil and gas activities. In addition to manuals and guidelines published on the Commission's website, permit holders should review directives, information bulletins, reports and safety advisories for any changes.

1.3.1 Permit Term and Expiry

Section 32(1) of the Oil and Gas Activities Act defines permit terms as:

- A permit and any related authorizations expire on the day after the prescribed period has elapsed if the permit holder has not begun constructing the permitted oil and gas activity.

The prescribed period of a permit is two years. OGAA permits remain active until cancelled, suspended, declared spent by the Commission or expires at the end of two years.

If the Commission has not received a permit extension application before the scheduled expiration date, the expired permit is removed from active records. A new application must be submitted if the permit expires but work is still required.

Extensions

To apply for a permit extension, permit holder must submit a completed Permit Extension Application Form including the required application deliverables prior to the scheduled expiration of the oil and gas permit.

To ensure adequate processing time, budget a minimum of three months prior to the scheduled expiration to submit and complete the Permit Extension Application Form.

If approved, the Commission may extend a permit and associated authorizations for up to one year. The extension may include additional conditions imposed by the Commission. If construction has not commenced by the end of the permit extension period, the permit is removed from active records unless the Commission is satisfied that there are special circumstances to justify a further extension, based on applicant request.

A decision to extend or not extend a permit is neither a reviewable nor appealable determination under OGAA.

1.3.2 Permit Notification

Following a permit approval, the Commission provides notice to the land owner(s) affected by the oil and gas activity. The notice cites specific details about the location of the approved activity, and the land owners' right to appeal if applicable.

The permit holder must wait 15 days from the day the permit is issued before commencing any oil and gas activity on private land, unless the land owner has consented to the permit holder in writing the oil and gas activity may commence. Written consent from a land owner is not provided to the Commission; however the permit holder should retain records for auditing purposes.

The permit holder must submit a notice of construction start to the Commission prior the start of operations. Additional pre-construction notices are required for roads. Minimum time requirements for submission of notice of construction start for various activities are outlined in the construction chapter of this manual.

1.3.3 Permit Amendments

Permit holders must submit an amendment application to add, modify or change any existing oil and gas and associated activity permit. Amendments are also required for corrections of inadvertent data errors where the error is in the permit or impacted on the decision. An amendment can include requests for multiple changes to an approved permit. Once an amendment is approved, the permit holder can apply for another amendment if required.

Engagement, consultation and notification requirements must be met if changes create alterations to the previous engagement, consultation and/or notification.

Amendments are submitted through the Application Management System and instructions on activity amendments are outlined in the Oil and Gas Activity Application Manual.

1.3.4 Permit Surrender and Cancellation

If a permit holder would like to request the cancellation of a permit after approval; the permit holder must submit a letter requesting cancellation of the permit. The cancellation request letter must clearly identify:

- Commission file number or Application Determination (AD) number.
- Legal description location.
- If surface disturbance has occurred and if the area has been reclaimed as per the Environmental Protection and Management Regulation (EPMR).
- Permit holder contact information including email address.

A confirmation letter/email will be sent to the permit holder upon cancellation of the permit and related authorizations/permissions.

If surrendering or cancelling a permit, other than a well site area, where surface disturbance has occurred, the area must be reclaimed as per section 19 of the Environmental Protection and Management Regulation.

Permits where no construction has taken place will be cancelled based on the submission of Post Construction.

1.3.5 Permit Transfers

A permit holder may apply to the Commission to transfer a permit under Section 29 of OGAA. For more information on the permit transfer process and transfer application requirements, refer to the Permit Operations and Administration Manual.

1.3.6 Permit Holder Name Changes and Transfers

In the event of a corporate amalgamation, corporate name change or other corporate structure change of a permit holder, submit appropriate documentation to the Commission. Upon receipt of all the correct documentation, the Commission facilitates the proper chain of title and current ownership of assets for billing and liability purposes. For more information on the corporate structure change process and requirements, refer to the Permit Operations and Administration Manual.

1.3.7 Permitted Use of Land

The Commission grants authority to occupy Crown land in one of two ways:

- Section 138(1) of the Petroleum and Natural Gas Act (PNG Act): For any oil and gas activities or related activities as defined in Section 1(2) of the Oil and Gas Activities Act (OGAA), the Commission will grant authority to occupy Crown land through Section 138(1) of the PNG Act. This is applicable for permits issued for a related activity, as defined in Section 1(2) of OGAA including either an associated Forest Act (e.g. cutting permit) or Water Sustainability Act (e.g. Section 11) authorization.
- Section 39 of the Land Act: If the permit for a stand-alone related activity only includes an authorization for the right to occupy Crown land (e.g. water storage site), with no other related activity as defined in Section 1(2) of OGAA, the permit will be granted as a licence under Section 39 of the Land Act.

As of Sept. 21, 2015, permits have been updated to replace reference to Section 14 of the Land Act with the appropriate permission or authorization to occupy Crown land. Any Section 14 Land Act authorization issued prior to Sept. 21 will remain valid until it expires, is deemed spent and replaced by a subsequent Land Act tenure, or is replaced via subsequent amendment of the permit with which it is associated.

The Commission issues the appropriate long term Land Act tenure upon acceptance of the post- construction plan. Submission of the original application and of the post-construction plan is considered application for all subsequent Land Act tenures; no further applications for replacement tenure is required.

1.4 Commission Authority Under Section 26 of OGAA

Under Section 26 of the Oil and Gas Activities Act (OGAA), the Commission has the authority to refuse, suspend, cancel, or amend a permit.

When making a decision under Section 26, the Commission can consider the conduct of an applicant or permit holder. In addition, the decision maker may look beyond the applicant or permit holder to consider the conduct of a person (which includes a corporation) associated with an applicant or permit holder.

An associate means any of the following:

1. an agent of the applicant or permit holder;
2. a director, officer or shareholder of the applicant or permit holder;
3. a person who, in the Commission’s opinion, may have influence over the applicant or permit holder or may be able to affect the activities permitted by the permit.

Section 26(2) and (3) of OGAA provide a non-exhaustive list of circumstances that may trigger a decision under Section 26. The following is a list of factors that the Commission may consider in making a decision under Section 26(1):

- Compliance history of the applicant or permit holder, or an associate of the applicant or permit holder.
- Corporate structure of the applicant or permit holder, or an associate of the applicant or permit holder.
- Experience of the applicant or permit holder, or an associate of the applicant or permit holder.
- Financial health of the applicant or permit holder, or an associate of the applicant or permit holder.
- Financing of the applicant or permit holder, or an associate of the applicant or permit holder.
- Outstanding debts owed by the applicant or permit holder, or an associate of the applicant or permit holder.
- Outstanding non-compliances of the applicant or permit holder, or an associate of the applicant or permit holder.
- The applicant or permit holder, or an associate of the applicant or permit holder, has been convicted of an offence as described in Section 26(2)(f) of OGAA.
- Involvement of the applicant or permit holder in bankruptcy or receivership proceedings.
- Involvement of an associate of the applicant or permit holder in entities that have initiated or are subject to bankruptcy or receivership proceedings.

In addition, the Commission may make a decision under Section 26(1) of OGAA where there is a relationship (such as employer / employee, officer, director or agent) between an applicant or permit holder and a permit holder that has previously been the subject of a decision under Section 26(1).

Before making a decision under Section 26(1)(b),(c) or (d) of OGAA to suspend, cancel or amend a permit, or under Section 26(5) of OGAA to suspend or cancel an authorization for a related activity, the Commission must provide the permit holder with an opportunity to be heard. The opportunity to be heard may be conducted in the time and format the Commission deems appropriate, pursuant to Section 80 of OGAA.

Chapter 2

Online Submission Requirements for Permit Holders

2. Online Submission Requirements for Permit Holders

The Commission maintains a web page of Online Services through which permit holders are required to submit information to the Commission during the various stages of the oil and gas activity's life cycle. This chapter provides an introduction to the online services and links to additional information for account set up, system navigation and using the system.

Users may access the Online Services from the Commission's website. It is recommended to access the online services through a high speed internet to maximize performance. Only one account is required to assess all the online services.

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2.1 Corporate Registry

The Commission maintains a corporate registry of companies. As part of the new company registration process, the Commission creates a system administration account for the applicant company. Companies must then designate authorized individuals with an application security role on behalf of a company.

2.2 Application Management System (AMS)

The Application Management System is an online portal applicants use to submit oil and gas and associated activity applications. Users may prepare multiple permit applications at the same time by selecting one or all of the activities of the oil and gas project. Multi-activity applications provide a complete picture of the project and the Commission encourages applicants to consider applying for all activities at the same time.

Registered applicants are ready to begin the application submission process once the pre-planning stages are complete and the administrators and/or agents for a company are registered in the Corporate Registry.

2.3 KERMIT

KERMIT is the Commission's Knowledge, Enterprise, Resource, Management, Information and Technology data system. KERMIT enables electronic submission of performance and/or compliance data and accepts various operational submissions related to oil and gas activities post approval. Access to KERMIT and documentation for using the KERMIT system is found on the Online Services page of the Commission's website.

2.4 eSubmission

eSubmission is an online portal to accept direct submission to the Commission of data and reports required by permit holders. Permit holder have regulatory requirements for information to submit to the Commission, including operational updates, spatial information and/or schematics of the oil and gas activity to keep the Commission abreast on the progress of the permitted oil and gas activity. Access to eSubmission and documentation for using the eSubmission portal is found on the Online Services page of the Commission's website.

2.5 Additional Online Services

In addition to the portals for online submission of applications and operational related materials, Online Services provides a number of online tools, services and reports including:

- eLibrary.
- Activity based statistics.
- Geospatial services and datasets.
- Area-based analysis.
- Data downloads and geology facility system.

For further information or assistance gaining access to these Online Services, follow the link on the page.

Chapter 3 Permit Holder Responsibilities

3. Permit Holder Responsibilities

This chapter provides an overview of permit holder obligations common amongst all oil and gas activity types.

Permit holders must obtain approval (as defined in OGAA) before starting any oil and gas or associated activity(s) and should maintain ongoing dialogue with the Commission and stakeholders throughout the life cycle of the project. This includes operational and reporting requirements and continued engagement as defined in the manuals and guidelines.

Permit holders must comply with the requirements imposed by the statutes and regulations of the province of B.C. and the guides, policies, and information letters issued by the Commission. Once approved, permit holders bear responsibility for all permit holder obligations (as defined in OGAA), including outcomes of actions of contracted personnel in carrying out permitted oil and gas activities on behalf of the company.

When completing an application and/or submitting additional reports, companies must provide engineering and technical information on activities carried out during the proposed term. Companies must provide true and accurate information and not knowingly omit relevant information. All data, attachments and requirements must be complete and accurate. If an agent or contractor submits information on behalf of the company, the applicant remains accountable for the accuracy of submission.

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Industry Standards

Permit holders should first and foremost adhere to the statutes and regulations of B.C. In addition, permit holders should have working knowledge and implement industry and professional standards, industrial practices, safety codes of practice, best management practices, and industry guiding principles. Some of these guiding standards are the foundations for sections and related requirements, such as the Canadian Standards Association and America Society of Mechanical Engineers. Others such as the Canadian Association of Petroleum Producers, Canadian Energy Pipeline Association, the Canadian Fuels Association and the International Organization for Standardization may be adopted by industry to ensure a strong focus on workplace safety and preventing accidents.

3.1 Associated Oil and Gas Activity

Associated oil and gas activities are related activities. Section 1 of Oil and Gas Activities Act defines oil and gas related activity as an activity:

- That, under a specified enactment, must not be carried out except as authorized under the specified enactment or that must be carried out in accordance with the specified enactment.
- The carrying out of which is required for or facilitates the carrying out of an oil and gas activity.

Permit holders must have an approval under the Petroleum and Natural Gas Act or Land Act for the use of Crown Land. The Commission does not issue authorizations for associated oil and gas activities on private land. Consider any additional regulations and requirements when operating borrow pits, mines, land farms and camps as follows:

- Work in and around a worksite borrow pit (defined as the excavation of clay, gravel, rock, shale, sand or soil used for the construction of oil and gas infrastructure) are subject to WorkSafeBc regulations.
- All oil and gas aggregate operations are considered a mining activity under the Mines Act and are subject to the requirements of the Health, Safety and Reclamation Code for Mines in British Columbia. WorkSafeBC regulations do not apply.

An oil and gas aggregate operation requires a Mines Act Permit in addition to a Licence of Occupation to occupy and use Crown land.

3.2 Environmental Stewardship

Companies must adhere to the Environmental Protection and Management Regulation (EPMR) of the Oil and Gas Activities Act (OGAA) in order to conduct oil and gas activities.

The Environmental Protection and Management Regulation (EMPR) establishes the regulatory requirements for stewardship of environmental values and features in the course of carrying out oil and gas activities on Crown land. With the exception of certain provisions which apply to all roads, the EPMR does not apply to oil and gas activities on private land. Please note that most stream crossings in BC are located on Crown land where the EPMR does not apply.

The Commission's Environmental Protection and Management Guideline (EPMG) provides specific guidance for permit holders in meeting the requirements of the Environmental Protection and Management Regulation.

Applicants and permit holders must plan and carry out oil and gas activities to avoid and/or minimize impacts to environmental values, mitigate impact where no realistic opportunity exists to avoid, and/or restore the impacted area to its pre-development state. General protection and best management approaches must continue during the operational stages so adequate management controls are in place and operations should be monitored to identify further opportunities to reduce environmental impacts.

Area-based Analysis

The Commission's Area-based Analysis (ABA) approach helps to minimize cumulative impacts on the landscape, reduce the footprint of activities, and shorten restoration / reclamation timeframes on specific resource values. Projects should minimize disturbance where possible. Guidance is available in the Commission's Supplementary Information for Area-based Analysis document and on the Area-based Analysis section of the Commission's website. Permit holders should continue to refer to and follow the guidance in these resources and keep apprised of updates by following the Commission's website.

Environmental Protection and Management Requirements

Part 3 of the EPMR prescribes operational requirements with respect to the items listed below:

- Water quality (for operating areas and adjacent areas).
- Aquifers.
- Crossings of streams, wetlands and lakes.
- Deleterious materials into streams, wetlands or lakes (oil and gas activities must not result in any deleterious material deposited).
- Operations within wetlands.
- Natural range barriers.
- Invasive plants.
- Forest health.
- Soil conservation.
- Seismic lines.
- Restoration of operating areas.

Permit Conditions

Permits may contain additional requirements permit holders must comply with during all phases of operation. It is prudent of permit holders to also have current knowledge and understanding of both the legal requirements and best practices to ensure stewardship of environmental values and features in the course of carrying out oil and gas activities.

Water Use

There are different ways permit holders may access water in British Columbia and seek permission. Refer to the Commission's Oil and Gas Activity Application Manual for water use permission and reporting requirements and the Commission's Water Licence Application Manual for water licence application details.

The Commission may restrict water usage, especially during times of drought in the case of water shortages or droughts. Water withdrawals from rivers and lakes can and will be suspended if necessary. Permit holders are responsible for keeping apprised of Commission updates by following the website for directives, bulletins, safety advisories and news releases.

3.3 Emergency Planning and Response Programs

The prevention of oil or gas emergencies requires operators to prepare, understand and minimize risks and adhere to legislative regulation, guidelines, industry standards, engineering codes and standards. Many of the regulations and standards are designed specifically to safeguard operations, but permit holders are required to check equipment, train employees and report to the Commission at various stages.

A permit holder is required to prepare and maintain an emergency management program and a emergency response plan for each of its oil and gas activities prior to carrying out those activities, as prescribed in the Emergency Management Regulation (EMR) and the Commission's Emergency Management Manual.

Incident Prevention

The Commission's Emergency Response and Safety web page provides guidelines, forms and information on emergencies, incident reporting and notification and annual exercise requirements. The Commission maintains a web page for Provincial emergency updates focussed on natural disasters which may affect oil and gas operating areas in B.C. The site includes direct links to up-to-date fire and other incident mapping, as well as training and preparation resources. Permit holders are encouraged to keep staff informed of evolving hazards and the procedures for reporting incidents by reviewing the documents on both pages.

3.4 Flaring and Venting

The Commission's Flaring and Venting Reduction Guideline provides guidance for flaring, incinerating and venting in British Columbia, as well as procedural information for flare approval requests, dispersion modelling and the measuring and reporting of flared, incinerated and vented gas.

Review the Flaring and Venting Reduction Guideline to understand flaring volume thresholds and time limits, public notification, guidance for flare stacks and incinerators and documentation. Specific sections of the wells and facility operations further discuss flaring and venting.

3.5 Archaeological Assessments

Permit holders must fulfill archaeological requirements pursuant to the Heritage Conservation Act and the Commission's archaeology guidelines as outlined in the Commission's Oil and Gas Activity Application Manual.

3.6 Roads Maintained by a Road Permit Holder

Section 21 of the Oil and Gas Road Regulation (OGRR) establishes requirements related to use, notification and contribution to maintenance costs associated with using an oil and gas road maintained by a road permit holder:

- Providing Notice of Use to the road permit holder at least 14 days before the intended use will begin.

If the road permit holder will be requiring that the permit holder enters into a cost-sharing maintenance agreement for road use, upon receiving a notice of intended road use, the road permit holder must provide to the permit holder providing the notice, an estimate of costs along with supporting data and records in relation to maintenance or any modifications necessary to accommodate the intended use of the permit holder, or to repair any damage caused by the user.

3.7 Noise Management

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 Commission's British Columbia Noise Control Best Practices Guideline for an understanding of noise levels, guidelines 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.

3.8 First Nations Engagement

Permit holders are encouraged to work with First Nations and consider any environmental, heritage and/or community concerns impacted by oil and gas activity by initiating and building relationships with First Nations communities during the project planning phase and continue the relationship throughout the project life cycle.

Under the Oil and Gas Road Regulation, permit holders are required to provide notice to local Indigenous nations pre-construction and before deactivation of an oil and gas road.

While not required prior to application, engagement with the public and First Nations within a pre-determined Emergency Planning Zone for Emergency Response Contingency Plans is encouraged since emergency plans must be in place for well, facility and pipeline permit holders prior to operation.

3.9 Land Owner and Rights Holder Engagement

Once a permit is approved, the Commission provides notice to the land owner(s) stating an oil and gas permit has been issued over the land.

Under the Oil and Gas Road Regulation, permit holders are required to provide notice to affected listed parties pre-construction and before deactivation of an oil and gas road.

Permit holders are encouraged to work proactively and collaboratively with those affected by oil and gas activity. The formalized public engagement process of consulting and engaging with land owners and/or rights holders are discussed in the Oil and Gas Activity Application Manual.

3.10 Restoration and Reclamation

Planning, construction and the oil and gas activity should take into consideration the entire life cycle of the project and the environmental and social impact of the proposed project. It is the intent of the Commission that oil and gas sites are temporary; therefore, careful planning beforehand is required to ensure a successful project end.

Regulatory and legal requirements cover the restoration of oil and gas sites no longer operating. Planning to reclaim a project starts early. For example, companies must minimize the disturbance to nearby land before and during a drilling operation. This decreases the amount of work necessary to return the area to its original state after the well is no longer producing.

Construction corridors are used to avoid or prevent disturbance to sensitive ecosystems and wherever practical, locate oil and gas and associated activity within the corridor.

During construction and ongoing operation of oil and gas activities, permit holders should take into account the eventual requirements for restoration and reclamation of land disturbed to facilitate the activity. When construction and/or operations are complete, restoration and reclamation should return the site to a similar state existing prior to disturbance.

Restoration and reclamation requirements are identified in Section 19 of the Environmental Protection and Management Regulation under OGAA. Guidance for planning and carrying out restoration and reclamation activities are in the following documents:

- Environmental Protection and Management guideline.
- Certificate of Restoration Application manual.
- Restoration Verification Audit Program Procedure manual.

Reclamation on ALR Land

The preliminary reclamation plan for activity falling within the Agricultural Land Reserve provides a brief description of how the site will be restored once it is no longer required for the oil and gas activity. This plan forms part of an ALR Schedule A report submitted with an application for the oil and gas activity (detailed in the Oil and Gas Activity Application Manual). The preliminary reclamation plan must include:

- Post oil and gas activity land-use objective.
- Soil handling.
- Re-vegetation.

In some cases, the submission of an ALR Schedule A report is not required until after the Commission has granted an oil and gas activity permit. In these cases, the ALR Schedule A report must be submitted via email to postpermitrequests@bcogc.ca for Commission review. The permit holder must receive a letter verifying that the report is to the satisfaction of the Commission prior to beginning construction activities.

Specific reclamation criteria for lands within the Agricultural Land Reserve are found in the site reclamation requirements as part of the Schedule B section in the Delegation Agreement, as well as on the Commission's website.

Schedule B Reports for pipeline right of ways must be submitted to the Commission within 24 months of Leave to Open submission for the pipeline. Schedule B Reports for wells must be submitted with the COR Part 2 application. For all other surface leases described in Schedule B of the Delegation Agreement, Schedule B Reports must be submitted in a timely manner after cessation of activity on the site, allowing for practicability of reclamation activities.

Schedule B Reports can be submitted in paper copy to the Commission's Fort St. John office, or via email to OGCwaste.management@bcogc.ca.

3.11 Compliance and Enforcement

Applicants have a legal obligation to meet all legislated requirements. The Commission expects applicants and permit holders to use formal practices in day-to-day operations and comply with the Oil and Gas Activities Act, the Commission's specified enactments, and all related regulations.

The Compliance and Enforcement Manual provides further information about the Commission's compliance processes. It is the permit holder's responsibility to know and uphold any legal responsibilities inside and outside of the Commission's legislative authority. The Commission audits and inspects permit holder activities and investigates incidents of alleged non-compliance.

3.12 Freedom of Information & Protection of Privacy

Throughout the course of application preparation and planning, the information collected from a person or other entity may contain personal information as defined by the Personal Information Protection Act (PIPA). Private sector organizations collecting personal information in British Columbia are subject to the PIPA, which sets out the rules for how personal information may be collected, used or disclosed.

Applicants and permit holders should comply with PIPA when collecting information from persons or entities and can contact the Office of the Information and Privacy Commissioner for British Columbia for more information.

As a public body, the Commission is subject to the Freedom of Information and Protection of Privacy Act (FOIPPA). Any personal information contained in plans or applications submitted to the Commission are subject to the protection and security requirements identified in FOIPPA.

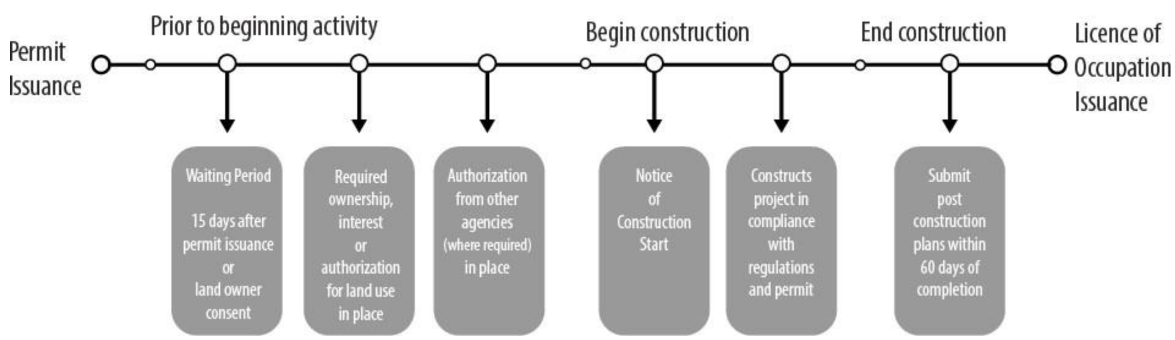
Confidentiality of Well Information

The Commission may make all or any portion of information included in well reports and well data publicly available on expiry of statutory confidentiality status of the well.

Chapter 4 Construction Details for Oil and Gas Activities

4. Construction Details for Oil and Gas Activities

Construction requirements are generally the same for all activities, with some further requirements or considerations for pipelines and facilities discussed in those relevant chapters. This chapter is organized chronologically based on the phases of a construction project and outlines the procedures and requirements, specifically:



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

4.1 Permitted Construction Activities

Permit holders are ultimately responsible for ensuring they understand and meet all legal and regulatory requirements and the permit, including all conditions attached to the permit. Construction activities must meet the design and operational requirements outlined in the following regulations and guidelines.

- Oil and Gas Activities Act (OGAA)
- Environmental Protection and Management Regulation (EPMR).
- Oil and Gas Road Regulation (OGRR).
- Pipeline Regulation and Pipeline Crossing Regulation.
- Drilling and Production Regulation (DPR).
- Geophysical Exploration Regulation.

Guidance Requirements

Activities should meet guidance recommendations in the following Commission documents:

- Environmental Protection and Management Guideline.
- Management of Saline Fluid for Hydraulic Fracturing Guideline.
- BC Noise Control Best Practices Guideline.
- Flaring & Venting Reduction Guideline.
- Measurement Guideline for Upstream Oil and Gas Operations.

Permit Condition: Construction Corridors

The construction corridor is an additional mapped area around the proposed activities providing the applicant or permit holder with the flexibility to adjust the proposed activities within the corridor. Providing all activities stay within the construction corridor, permit holders have the ability to move ancillary sites or add area without having to submit an amendment.

Applicants should consider construction corridors as part of the application to ensure flexibility to use the construction corridor during operation. The construction corridor will form part of the permit. Refer to the Commission's Oil and Gas Activity Application Manual for further details.

Permit holders must submit an amendment if changes are required for construction activities impacting any area outside of the construction corridor or if a construction corridor was not established.

4.2 Pre-Construction

Prior to beginning construction activity, permit holders must meet mandatory timelines, meet the requirements for land or surface access and obtain approval from other agencies prior to pipeline activity, where applicable and as detailed in this section.

4.2.1 Construction Start Dates

Permit holders must wait 15 days from the day the permit is issued before commencing any oil and gas activity on private land, unless the land owner has consented in writing that the oil and gas activity may commence. Written consent from a land owner is not required to be submitted to the Commission; however the permit holder should retain records.

4.2.2 Land or Surface Access

Permits for oil and gas activities on Crown land include authorization to occupy Crown land. The authorizations are granted under the Petroleum and Natural Gas Act or the Land Act.

The Commission may permit the construction and operation of oil and gas or associated oil and gas activities on private land, but access is subject to a land owner agreement. Refer to the Land Owner and Rights Holder section of the Oil and Gas Activity Application Manual for more information on land owner notification for activities on private land.

4.2.3 Altering the Lands (Removal of Vegetation)

Stumpage

The applicable Ministry of Forests, Lands and Natural Resource Operations Appraisal Manual (Interior or Coast) outlines the process for determining stumpage payable on cutting permits issued for oil and gas development.

In the Fort Nelson, Mackenzie, Peace and Rocky Mountain districts, stumpage for timber cleared for most oil and gas purposes is calculated on a per-area basis. For these permits, as-cleared information reported by the permit holder on the post-construction plan or geophysical final plan submission is forwarded to the Ministry of Forests, Lands and Natural Resource Operations. As-cleared area is multiplied by the reserve stumpage rate for the district to determine stumpage payable.

For cutting permits outside of the districts noted above, or for pipeline rights-of-way over 2,000m^3 of timber volume, stumpage is calculated on a per-volume basis.

Stumpage Waste Assessment

Permit holders cutting Crown timber are required, regardless of utilization, to report and pay the province for the timber. According to the specifications detailed in the Master Licence to Cut, exempted merchantable fibre, outside the Forest Districts described in the Interior Forest Appraisal Manual must have a waste survey completed and ensure stumpage is billed accordingly.

Timber Marking

Timber marking must be carried out in accordance with the Timber Marking and Transportation Regulation.

Water Use and Stream Crossing

Permit holders requiring access to water and/or require stream crossing during construction, must seek permission prior to construction. Works in and about a stream may also require review by DFO under the federal Fisheries Act.

Refer to the Commission's Oil and Gas Activity Application Manual for water use permission and reporting requirements and the Commission's Water Licence Application Manual for water licence application details.

4.3 Beginning Construction

Permit holders must complete a Notice of Construction Start and specific construction requirements pertaining to wells, pipelines, facilities, and roads are discussed in detail in each respective chapter of this manual.

4.3.1 Notice of Construction Start

Prior to beginning construction submit a notice of construction start. Required submission methods and timelines differ between activity types. Notices must be submitted prior to commencement of land clearing and/or the set-up of equipment on location. Notices are submitted by AD number and start date. A new notice must be submitted for each start date.

Table 4.1 below identifies the activity type where a notice of construction start is required, summary of submission methods and timelines for each activity type.

Table 4.1 Notice of Construction Submission by Activity

Activity Type	Submission Method	Submission Timeline
Well	Online Submission by eSubmission system.	Notice must be submitted at least 48 hours before construction is to begin.
Facility	Online Submission by KERMIT system.	Notice must be submitted at least two days before construction is to begin.
Pipeline	Online Submission by KERMIT system.	Notice must be submitted at least two days before construction is to begin.
Road	Online Submission by eSubmission system.	Notice must be submitted within at least 72 hours and not more than 30 days prior to starting construction.

Associated Oil and Gas Activity	Online Submission by eSubmission system.	Notice must be submitted at least 48 hours before construction is to begin.
Stream Crossing	Online Submission by eSubmission system.	Notice must be submitted at least 48 hours before construction is to begin, or as per the permit, if activities under the stream crossing authorization are not part of current construction of an another activity where a notice of construction start has been submitted.
NEB Road	Online Submission by eSubmission system.	Notice must be submitted at least 48 hours prior to the commencement of activities under this permit.
NEB Ancillaries	Online Submission by eSubmission system	Notice must be submitted at least 48 hours prior to the commencement of activities under this permit
NEB Pipelines	Online Submission by KERMIT system	Notice must be submitted at least 48 hours prior to the commencement of activities under this permit
NEB Facilities	Online Submission by KERMIT system	Notice must be submitted at least 48 hours prior to the commencement of activities under this permit

Notice of Maintenance

The permit holder must submit a notice of maintenance to the Commission two (2) working days prior to the commencement of any change in or about a stream associated with maintenance activities, as authorized in the permit. Minimum time requirements for submission of notice of maintenance for various activities are outlined in the regulations and/or permit conditions specific to the activity.

A Notice of Maintenance is submitted by completing a Notice of Maintenance Form and submitting by email to OGC.ExternalNotifications@bcogc.ca

Permit Expiry

In order to satisfy the requirements of 'beginning an oil and gas activity' and to prevent the permit from expiring, permit holders need to submit a Notice of Construction Start (NCS) or apply for a Permit Extension.

Once a NCS has been submitted to the Commission, the permit will be considered valid and will no longer be subject to Section 32(1) of the Oil and Gas Activities Act. All of the activities permitted and authorized under one application, will be considered valid once the NCS has been submitted.

If the Commission has not received a Notice of Construction Start (NCS) or processes and approved a permit extension application prior to its expiry, the permit will be deemed expired.

Information on the Commission's permit extension process is available in Chapter 8.2 of the Oil and Gas Activity Application Manual.

Additional Notification Requirements for Roads

Oil and gas road permit holders must notify local Indigenous Nations, affected land owners, affected permit holders, and affected rights holders at least 72 hours, and not more than 30 days, prior to beginning construction. Where construction must be carried out expeditiously to address an environmental or operational emergency, notice of construction start must be provided to the Commission, local Indigenous Nations, affected land owners, affected permit holders, and affected rights holders as soon as practicable.

Notices to local Indigenous Nations, affected land owners, affected permit holders, and affected rights holders must be made in writing and include the following:

- Location of the road.
- Applicable road permit number and any administrative identifier relating to the road.
- Contact name and contact information.
- Date construction started or began, as applicable, and the date construction will be complete or was completed.

Before deactivation, a road permit holder must notify the Commission, local Indigenous nations, affected land owners, road users known to the road permit holder and the local forest district office at least 30 days, and not more than 60 days, prior to beginning deactivation. Any objection to the deactivation must be promptly forwarded to the Commission. Notices must be in writing, identify the road to be deactivated and specify the date when deactivation will begin.

4.4 Post Construction

4.4.1 Post Construction Plan

With the exception of geophysical activities, a post construction plan must be submitted to the Commission within 60 days of completed construction for all oil and gas activities and associated oil and gas activities where new land has been cleared or disturbed for construction. More information on post construction plan submissions is provided in the Commission's Permit Operations Administration manual.

Chapter 5 Geophysical Activity

5. Geophysical Activity Requirements

The geophysical activity section of this manual provides operating guidelines for regulatory requirements throughout the operations life cycle of the permitted activity. Construction activities are discussed in Section 4 of this manual. Associated oil and gas activities, if required in addition to the oil and gas activity permit, are touched on in Section 3.1 of this manual.

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

5.1 Geophysical Permitted Activities

All permit holders are ultimately responsible for ensuring they understand and meet all legal and regulatory requirements of the permit, including all conditions attached to the permit.

5.1.1 Geophysical Defined

Geophysical exploration is an oil and gas activity under the Oil and Gas Activities Act (OGAA) and is specifically defined in the Petroleum and Natural Gas Act (PNG) Act as:

- Investigation of the subsurface by seismic, gravimetric, magnetic, electric and geochemical operations and by any other method approved by the Commission, but does not include the use of geophysical well logs, vertical seismic profile surveys or other surveys obtained from a well.

5.1.2 Regulatory Requirements

Geophysical exploration activities must meet the design and operational requirements outlined in the Oil and Gas Activities Act (OGAA), Geophysical Exploration Regulation (GER) and the Environmental Protection and Management Regulation (EPMR).

5.1.3 Guidance Requirements

Geophysical exploration activities should meet guidance recommendations in the following documents:

- Environmental Protection & Management Guideline.
- Horn River Basin and Muskwa-Kechika Management Area Guidance Document.

Permit Condition: Geophysical Line Shift Variances

Geophysical line shift variances provide the permit holder with the flexibility to adjust geophysical lines one way or another within the variance permitted. Providing line shift variances comply with buffer distances, permit holders have the ability to adjust geophysical lines without having to submit an amendment.

Applicants should consider geophysical line shift variances as part of the application to ensure flexibility to use during operation. Refer to the Commission's Oil and Gas Activity Application Manual for further details. Permit holders must submit an amendment if changes are required for activities impacting any area outside of the line shift variance or if a variance was not established.

5.2 Geophysical Reporting

The Commission is tasked with the management and oversight of the permissions and authorizations issued under OGAA and other statutes. As a result, OGAA and its regulations contain a series of fixed communication points ensuring the Commission receives the necessary information, data or general communications required. Receiving this information allows for the reconciliation of permits, authorizations and most importantly ensures the Commission is apprised of events and actions of a permit holder; therefore, influencing our ability to verify the status of each activity.

The following section provides a description of the processes and the means of submitting relevant information, as wells as providing some clarity on the regulatory expectations for geophysical reporting.

Date of Commencement

The geophysical regulation requires permit holders to define the actual date operations commenced. Unlike other oil and gas activities, the "Date of Commencement" as defined in regulation, does not require holders to notify the Commission prior to initiating operations.

Under the geophysical regulation the "Date of Commencement" must be entered during the first Geophysical Project Report (i.e. the first Monday following commencement).

5.2.1 Geophysical Project Reporting (Weekly Report/Monday Report)

The Geophysical weekly project reports facilitate the Commission's awareness of a program's development allowing for effective communication between operators and the Commission. The process ensures the Commission has sufficient information available to handle public and First Nations inquiries while also supporting effective communications between operators and the Commission's compliance and enforcement staff.

The Geophysical Exploration Regulation (GER) has specific requirements for survey monuments, hole plugging, hole shots, misfired charges, flow of gas or water, refuse removal and campsite cleanup and restoration including actions to be taken. Permit holders are required to review these sections regularly. The Commission recommends that (for the purposes of GER Section 5 (1) (c)), bentonite, at a minimum, is a suitable material to fill a shot hole above a plug on private land.

The Geophysical Project Report is submitted every Monday (before noon) following the date of commencement, and on each subsequent Monday while the project is in progress.

The Geophysical Project reporting process enables the submission of information required for public safety and may include:

- Flowing holes (water or gas flow released to surface as a result of drilling) according to Section 8 of GER.
- Misfired charge. Part of the Commission's mandate is to ensure misfired charges are effectively managed for and reported to ensure future initiatives are made aware of potential hazards. Review Work Safe BC's Misfired Procedures. Misfired charges are reported to the Commission via the weekly report (while programs are active). They are also included in the final plan submission (detailed on map).
- Handling requirements according to Section 7 of GER.
- Monument moved, damaged or destroyed.
- Land or property damage occurs.
- Temporary shutdowns if the temporary shutdown will last greater than five days. Report the shutdown start date and estimated re-start date ("shutdown Start Date").

Reporting requirements are detailed in Section 2(2)(f) of GER. Submit the Geophysical Project Report through eSubmission. Access to eSubmission and documentation for using eSubmission is found on the Online Services page of the Commission's website.

Date of Completion

The date the acquisition of data is completed (i.e. recording 100 per cent complete). The submission of a completion date signifies the permitted activities are complete (permit granted is exhausted or no-longer required). The completion date is a precursor for the submission of a Final Plan.

Final Plans

Final Plans are required within 60 days of the completion of a geophysical project according to Section 2 of GER. All geophysical final plans are submitted through eSubmission portal. Please see Section 2(6) of the GER provides detailed content requirements for Final Plan submissions.

Program Cleanup

As required in Sections 9 through 12 of GER, the submission of a Completion Date signifies a permit is spent and no additional geophysical harvesting, drilling or recording will be undertaken. Permit holders are responsible for any cleanup operations, regardless of the permit being deemed spent. The Commission recognizes that winter conditions (for example: snow fall) may affect the cleanup stage; therefore, clean-up activities may require permit holders to revisit the site during snow free conditions.

Garbage

The Commission expects field cleanup activities be carried out prior to June 1st following the previous winter.

Stream crossings

Restoration of stream crossings (for example: snow fills) is viewed as operational activity, meaning that crossing should be removed immediately following the completion of recording.

Chapter 6 Road Activity

6. Road Activity

The road activity section of this manual provides operating guidelines for regulatory requirements throughout the operations life cycle of the permitted activity. Construction activities are discussed in Section 4 of this manual. Associated oil and gas activities, if required in addition to the oil and gas activity permit, are touched on in Section 3.1 of this manual.

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

6.1 Road Permitted Activity

All permit holders are ultimately responsible for ensuring they understand and meet all legal and regulatory requirements of the permit, including all conditions attached to the permit. If an exemption is requested from regulatory requirements, an exemption must be prepared at the time of application. Permit holders must contact the Commission prior to commencing construction or operations if the adherence to the permitted activity cannot be met. The Commission may be able to provide further guidance and clarification.

6.1.1 Roads Defined

Oil and gas roads are prescribed as an oil and gas activity in OGAA and are defined within the Oil and Gas Road Regulation (OGRR) as:

(1) (a) A road or portion of a road that is constructed or maintained to facilitate the carrying out of a primary activity;

(b) A road or portion of a road that was constructed before June 3, 2013 [the coming into force of the Oil and Gas Road Regulation] under the Land Act, the Petroleum and Natural Gas Act [or as a Petroleum Development Road] or [that provided access under] the Pipeline Act and has been used to facilitate the carrying out of a primary activity.

(2) Subsection (1) does not apply to a road that

(a) has been deactivated, or

(b) is required to be maintained under an enactment other than

(i) this regulation, and

(ii) an Act referred to in subsection (1) (b).

Approved oil and gas road applications receive a permit under Section 25 of OGAA to construct and maintain the road. The road permit expires where construction activities have not started within two (2) years of permit issuance. Unless expired, the road permit remains active until cancelled, suspended or declared spent, according to the provisions of OGAA.

The OGRR prescribes the rights and obligations of permit holders related to design, construction, maintenance, use and deactivation of oil and gas roads.

6.1.2 Regulatory Requirements

Roads must meet the design and operational requirements outlined in the Oil and Gas Activities Act (OGAA), the Oil and Gas Road Regulation (OGRR) and the Environmental Protection and Management Regulation (EPMR).

- Part Part 2 of OGRR outlines requirements related to: identification of construction areas, if there is nearby access, providing rationale for why new construction is needed, and notice of construction.
- Part 3 of OGRR outlines requirements related to road construction including: supervision of design, construction and maintenance by a qualified person, clearing widths, bridges and culverts, borrow pits,

record keeping requirements, hazard warnings and post-construction reporting.

Permit holders must include stream crossing requirements in the application to make changes in or about a stream. OGRR regulates construction of bridges and/or culverts as part of a road to facilitate a crossing. A WSA Section 11 approval may also be required. Permit holders must be aware of and abide by Canadian Standard Association and Canadian Highway Bridge design codes for bridges or culverts. A federal Fisheries Act review may also be required by DFO.

6.1.3 Guidance Requirements

Roads should meet guidance recommendations in the following documents:

- Environmental Protection and Management Guideline.
- Motor Vehicle Prohibition Regulation.

6.2 Roads Operational Requirements

6.2.1 Road Use Requirements Applicable to all Oil and Gas Permit Holders

Permit holders must review and comply with OGRR:

- Part 3: outlines requirements related to road maintenance including: general and technical road maintenance, ongoing restoration, borrow pits, bridge maintenance, and limited maintenance related to temporary stoppage in road use.
- Part 4 of OGRR outlines requirements related to streams and stream crossings.
- Part 5: sets out road use and operation provisions and requirements including: right of access, limited application of the Motor Vehicle Act to oil and gas roads, speed restrictions, use and requirements related to traffic control devices, storage and disposal, temporary closures, temporary

restriction of access, removal of objects, and the use of oil and gas roads maintained by a road permit holder.

- Part 6: prescribes requirements for road permit holders in relation to road deactivation including: supervision of deactivation by a qualified person, notice, maintenance, hazard warnings and signed statement of compliance.

Road permit holders are required to maintain oil and gas roads until they are deactivated, or they are relieved from deactivation.

Where in stream works are required for maintenance activities, such as bridge or culvert maintenance, the road permit holder must have or obtain a new Section 11 Water Sustainability Act authorization for changes in and about a stream from the Commission prior to carrying out the activities. A review under the federal Fisheries Act may also be required by DFO for any changes in or about a stream.

6.2.2 Notice of Road Usage

As outlined in section 21 of the Oil and Gas Road Regulation (OGRR), any oil and gas activity permit holders intending to use an oil and gas road must provide notice of the intended use to the road permit holder at least 14 days before the intended use will begin. If there is no road permit holder on the oil and gas road, you must apply for a road permit in order to use the road.

Upon receiving a notice of intended road use the road permit holder must provide to the permit holder providing the notice, an estimate of costs along with supporting data and records in relation to maintenance or any modifications necessary to accommodate the intended use of the permit holder, or to repair any damage cause by the user.

Types of Traffic - The obligation of a permit holder under Section 21(2) of the OGRR is to make a reasonable contribution to the expense of the road permit holder maintaining/modifying and repairing the road in relation to the permit holder's use and needs. This doesn't necessarily exclude specific types of traffic (i.e. pickup trucks), but the relevant expenses relating to the use of pickup trucks for example, might be less than other types of traffic.

Road Use Agreements – The OGRR requires that permit holders provide notice of road use (Section 21(1)) and pay the contribution identified in Section 21(2), however road use agreements are not required. This requirement does not preclude the use of contracts between permit holders and road permit holders, which may be desired to set out terms of agreement that go beyond the scope and requirements of OGRR.

6.2.3 Forest Service Roads

If the proposed road enters or affects a Forest Service Road right-of-way, or Ministry of Transportation and Infrastructure (MOTI) right-of-way, consent to carry out the approved activities must be obtained from the applicable agency before the project begins.

A road use permit (RUP) is required to use Forest Service Roads to carry out oil and gas activities. Where an RUP is not already held, one can be obtained by submitting a completed RUP application form via email to RoadUsePermits@bcogc.ca. For additional information on road use permit administration, please refer to the road use permit tenure administration guidance document for oil and gas.

6.3 Roads Use Status Changes and Closures Requiring Commission Notice

Roads must be operated and maintained until deactivated, while they are required for the primary oil and gas or related activity for which they were constructed. When this is not the case, notification must be provided where applicable and as required in the following scenarios:

- Periods of Limited Maintenance.
- Temporary road closures or restrictions.
- Road use resumption.

6.3.1 Periods of Limited Maintenance

Under Section 15 of the OGRR, a road permit holder who stops using an oil and gas road for a period of more than six months to carry out a primary oil and gas related activity, may transition the road to a status of limited maintenance by submitting a notice to the Commission.

Maintenance obligations under the status of limited maintenance:

- The permit holder must ensure the structural integrity of the road prism and clearing widths are stable,
- The road drainage systems remain functional to the extent necessary to ensure there is no material adverse effect on fish, fish habitat, water quality or quantity, wildlife or wildlife habitat, and
- Maintain all bridges, major culverts and engineered retaining walls as per Section 14 of the OGRR (Maintenance of bridges, major culverts and engineered retaining walls).

In order to transition a road to limited maintenance, the following must be true:

- the permit holder is not using the road, and will not resume use for at least 6 months,
- there are no other active road users under Section 21 maintenance agreement, and

The Notice of Temporary Stoppage of Road Use must be submitted to the Commission within 30 days of stoppage in use. Submit by email to OGC.ExternalNotifications@bcogc.ca using the Road Notification Form.

For information regarding resumption of use, refer to Section 6.3.3 of this manual.

6.3.2 Temporary Road Closure or Restriction

Under Section 20 of the OGRR a road permit holder may temporarily close or restrict access if the action is necessary to address an existing or imminent threat that may cause damage to the road or to the environment or endanger human life or property.

Under such circumstances, the Permit Holder must promptly notify the Commission. The notices must be submitted to the Commission by email to OGC.ExternalNotifications@bcogc.ca using the Road Notification Form.

For clarity, the use of Section 20 should be viewed as distinct and independent of the actions/authorities outlined in Section 19 of the OGRR. Section 19 provides the necessary authority for permit holders to install traffic control devices without the need to notify the Commission when conducting road operations.

For example, a hole in bridge decking requires the road before the bridge to be closed in accordance with Section 7, and under Section 20 of the OGRR, as the use of the bridge is not safe. The duration of the closure is limited to the time required to organize materials, equipment, contractors, etc. to fix the issue.

A road permit holder may also restrict access to any portion of the oil and gas road located on private property, other than access in accordance with section 21 or for land owner uses.

Please refer to Section 20 of the OGRR to understand the full scope of requirements imposed on Permit Holders when closing or restricting access.

6.3.3 Road Use Resumption

The Notice of Road Use Resumption informs the Commission when a temporary stoppage of road use ends and the road use will resume.

The Notice of Road Resumption must be submitted to the Commission upon restarting use of the road. Submit by email to OGC.ExternalNotifications@bcogc.ca using the Road Notification Form.

The Commission recommends permit holders also notify land owners, rights holders and Indigenous Nations who may be affected by the change in road status.

6.4 Road Amendments and/or Transitions

The transition of roads from non-status to oil and gas road permits is carried out to ensure all existing roads currently used or proposed for imminent use for oil and gas activities are under a valid road permit. Applications to transition existing non-status roads to oil and gas road permits must follow the non-status road transition application process as outlined in the Oil and Gas Activity Application Manual.

Non-status roads include, but are not limited to, non-tenured roads built by other resource sectors or roads originally constructed under Section 7 or 138 of the Petroleum and Natural

Gas Act where there is no clear single OGAA permit holder for the road or the oil and gas infrastructure accessed by the road.

6.5 Road Deactivation Requirements

Permit holders must comply with the requirements of Part 6 Deactivation of Oil and Gas Roads under the OGRR and Section 19 of the EPMR related to oil and gas road deactivation, including: oversight by a qualified person, timing of deactivation, notice of intent, maintenance and hazard warnings during deactivation, restoration and declaration of completed deactivation where applicable and as detailed in this section.

6.5.1 Timing of Deactivation

A road permit holder may deactivate a permitted road at any time, except where prohibited from carrying out deactivation by the Commission. However, roads or portions of roads providing access to a well, pipeline, facility or an associated activity must be deactivated when restoring the land that was used for the primary activity associated with the road.

6.5.2 Notice of Intent to Deactivate a Road

The Notice of Intent to Deactivate a Road informs the Commission, known users of the road (known to the permit holder) and any affected land owners, local Indigenous Nations and the local Forest District offices of the permit holder's intent to deactivate a road.

The Notice of Intent to Deactivate a Road must be submitted to the Commission, as per Section 23(1) of the OGRR, and the permit holder must notify all known road users, local Indigenous Nations, affected land owners and the Forest District offices of the deactivation at least 30 days prior to deactivating the road.

The submission must include:

- Road Notice of Intent to Deactivate Form
- Map

- Date of planned deactivation

The permit holder must retain a copy of the Notice and if the permit holder receives written responses, retain a copy of each response. A response that objects to the deactivation must be promptly submitted to the Commission.

Submit to the Commission by email to OGC.ExternalNotifications@bcogc.ca using the Road Notice of Intent to Deactivate Form.

The Commission reviews the Notice of Intent to Deactivate a Road with consideration to current and potential road users. As a result, the Commission may:

- Extend the 30 day notification period.
- Prohibit deactivation activities.
- Relieve the permit holder from the obligation to deactivate.

Deactivation activities cannot begin until at least 30 days have passed after providing the notice.

If the permit holder completes the deactivation, the permit holder must prepare a report, within 30 days after completion, that summarizes the responses and identifies the measures, if any, that the road permit holder took to address them, and retain a copy of the report.

6.5.3 Restoration and Signed Statement of Road Deactivation

Restoration should include as a minimum, removal of culverts and bridges, and any engineered structures that may fail, stabilization of the roadwork area, restoration of the natural drainage patterns and re-vegetation with ecologically suitable local native plants. Roads within the Agriculture Land Reserve must also meet the reclamation standards of Schedule B of the ALC-OGC Delegation Agreement. Requirements for deactivation and restoration on private land are subject to land owner or surface lease agreements.

Work in and about a stream requiring the removal of bridges or culverts during road deactivation activities require a Section 11 Water Sustainability Act authorization and may require review under the Federal Fisheries Act by DFO. If the permit holder has an existing WSA Section 11 authorization for the crossing, a new one is not required.

The Signed Statement is a dated statement affirming compliance with the road deactivation requirements set out in Section 24 of OGRR, including restoration as per Section 19 of the Environmental Protection and Management Regulation, as applicable.

The Signed Statement must be submitted to the Commission within 30 days of completing deactivation. Submit by email to OGC.ExternalNotifications@bcogc.ca, using the Declaration of Road Deactivation Form.

Chapter 7 Well Activity: Overview

7. Well Activity: Overview

The wells activity section of this manual provides operating guidelines for regulatory requirements throughout the operations life cycle of the permitted activity. Permit holders must complete a Notice of Construction Start as detailed in Chapter 4 of this manual. Prior to beginning construction, submit a Notice of Construction Start via eSubmission. Notices must be submitted prior to commencement of land clearing and/or the set-up of equipment on location and at least 48 hours before construction is to begin. Associated oil and gas activities, if required in addition to the oil and gas activity permit, are touched on in Section 3.1 of this manual.

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

7.1 Wells Permitted Activities

All permit holders are ultimately responsible for ensuring they understand and meet all legal and regulatory requirements of the permit, including all conditions attached to the permit. If an exemption is requested from regulatory requirements, an exemption must be prepared at the time of application. Permit holders must contact the Commission prior to commencing construction or operations if the adherence to the permitted activity cannot be met. The Commission may be able to provide further guidance and clarification.

Section 4 of the Drilling and Production Regulation (DPR) provides a list of sections to which an exemption may be granted. Requests for an exemption or variance after the permit is issued should be submitted for approval to the Commission's Drilling and Production department.

7.1.1 Wells Defined

Wells are an oil and gas activity as defined in OGAA, and are specifically defined in the Petroleum and Natural Gas Act as:

A hole in the ground:

a) Made or being made by drilling, boring or any other method to obtain petroleum or natural gas.

b) Made or being made by drilling, boring or any other method to explore for, develop or use a storage reservoir for the storage or disposal of petroleum, natural gas, water produced in relation to the production of petroleum or natural gas, waste or any other prescribed substance.

c) Used, drilled or being drilled to inject natural gas, water produced in relation to the production of petroleum or natural gas or other substances into an underground formation in connection with the production of petroleum or natural gas.

d) Used to dispose of petroleum, natural gas, water produced in relation to the production of petroleum or natural gas, waste or any other prescribed substance into a storage reservoir, or

e) Used, drilled or being drilled to obtain geological or geophysical information respecting petroleum or natural gas.

And includes a water source well.

7.1.2 Regulatory Requirements

Well activities must meet the design and operational requirements outlined in the Oil and Gas Activities Act (OGAA), Drilling and Production Regulation (DPR), the Environmental Protection and Management Regulation (EPMR).

Additional legislation, regulations and/or standards permit holders should adhere to include:

- Contaminated Sites Regulation (CSR)
- Oil and Gas Waste Regulation (OGWR).
- Hazardous Wastes Regulation (HWR).

- Spill Reporting Regulation (SRR).
- Inline Testing Directive.
- Well Data Submission Requirements Manual

7.1.3 Guidance Requirements

Well activities should meet guidance recommendations in the following Commission documents:

- Management of Saline Fluid for Hydraulic Fracturing Guideline
- British Columbia Noise Control Best Practices Guideline
- Flaring and Venting Reduction Guideline

7.2 Well Permit Amendments

A well permit amendment is required for changes to approved well permits as outlined in the following scenarios. Approval of a permit amendment is required before the associated changes are carried out. Amendment scenarios include:

- Surface footprint (surface disturbance) is changed.
- Objective formation(s) or the formation at total depth has changed.
- Expected hydrogen sulphide (H_2S) release rate is changed, resulting in a change of the emergency planning zone.
- Change blowout prevention from the class in the well permit to a lower class.
- Change in surface wellhead coordinates results in change in the well name (example: the pad is located in a boundary and the change causes the well name to change from 1-3 to 3-3).
- Change in BHL with attendant changes in well profile such that the well name adds or deletes “HZ”

Well permit amendments must receive permission for flaring which is not included in the original permit, nor found in Section 42 of the Drilling and Production Regulation.

Permit amendments are not required:

- For minor changes if the proposed final total depth (FTD) resulting from geological prognosis change, simple changes to hole size or casing size, addition of a core or a drillstem test (DST) or minor changes in well centre coordinates.
- When changing well head location if there is no change to wellsite location or to well head surface location (NTS or DLS coordinates). For example, a permit amendment is not required when moving the well head within the well site area, but new coordinates must be reported on the Summary Report of Drilling Operations (SRDO). See section 8.2.1 of this manual for further information on the SRDO.

A well permit amendment is submitted through the Commission's Application Management System. Refer to the Oil and Gas Activity Application Manual for specific details. Minor changes in surface wellsite co-ordinates are collected in the eSubmission portal using the Summary Report of Drilling Operations.

7.2.1 Well Re-entries

A drilling re-entry is defined as additional drilling on a well that had previously been drilled and rig released. A well permit amendment is required to re-enter a well that has not been issued a Certificate of Restoration (CoR). A new well permit is required to re-enter a well issued a CoR. Refer to the Oil and Gas Activity Application Manual for the permit application and amendment processes.

7.2.2 Junked or Lost Hole Policy

When a problem is encountered in drilling a well, the drilling rig can be skidded and a new well spudded under the same well permit providing:

- The surface casing has not been set and data (for example, sample) has not been collected.

The skidding of the rig and drilling of the new hole may proceed without delay, but the well operator must submit an amendment and attach copies of the new survey plan.

If surface casing has been set on a drilling well and the hole below the shoe is junked or lost due to drilling problems, a new well permit is required to skid the rig and drill a new hole. In these situations the permit processing may be expedited by the Commission provided no changes to the existing location are required.

7.3 Well Data and Well Data Submission

Drilling activities must be reported to the Commission in accordance with Section 8 of the Drilling and Production Regulation and any well permit conditions. Any questions or problems should be directed to the Drilling and Production Department, Engineering Operations Technician.

Well Reports and Well Data are defined in Section 14 of Oil and Gas Activities Act General Regulation as information obtained from or about a well, including drill cuttings, core samples and several specific types of data, reports, surveys and information. The Drilling and Production Regulation provides submission requirements for well reports and well data. Further guidance on submission processes and requirements is available in the Commission's Well Data Submission Requirements Manual.

The Commission holds and releases confidential well reports and well data as per Section 17 of the Oil and Gas Activities Act General Regulation.

Special Data Well Designation

The special data well designation was introduced to recognize operators for obtaining specified, high value well data by providing extended confidentiality to a period of 18 months from rig release date. Refer to the Commission's Summary Information: Special Data Wells document for further information on application requirements, processes and considerations.

Discovery Well Designation

A discovery well is a well from which, in the opinion of a designated Commission official, sufficient information has been obtained to determine that the well has encountered a previously undiscovered pool. Wells designated as Discovery Wells are classified as exploratory wildcat under Section 2(3) of the Drilling and Production Regulation, extending the confidentiality period to the duration specified in Section 17(1) of OGAA. Refer to the

Commission's Summary Information: Discovery Wells document for further information on application requirements, processes and considerations.

SIMOPs (Simultaneous Operations) Plan Requirements (Previously Concurrent Operations Plan)

Definition

SIMOPs: any situation where two or more operations are close enough to interfere with each other, or transfer risk or performance implications between them.

Operations: performing drilling, completion, well intervention, construction or production activities.

Scope

This requirements is to ensure consistency in the identification and mitigation of risk associated with simultaneous operations on a well site/pad in which existing offset well(s) or other infrastructure are at risk from the simultaneous operations. Note: the resultant impact/damage is not necessarily limited to an uncontrolled release of hydrocarbons.

Section 12 of the Drilling and Production Regulation (DPR) requires that permit holders minimize the risk of loss of well control, which includes addressing operations beyond well interventions. Permit holders must design and implement a SIMOP plan in a manner that supports safe life of well operations for existing and proposed infrastructure, and in a manner that protects public health and safety, protects the environment, and for the conservation of natural resources.

Examples of situations where a SIMOPs plan are required include, but are not limited to:

- A permit holder drills a new well that requests a spacing variance, or where the impact radius of the equipment required to drill and complete the new well could strike an existing well(s) or associated production facilities.
- Stimulate, complete, service or abandon a well where existing wells or production facilities could be affected by the well intervention.

SIMOPs Plan Contents

- Summary statement that documents the location and briefly details the combined operational processes (drilling, completion, workover, well service, plug and abandonment) that will occur during the operations.
- Summary of the hazard identification and risk assessment conducted respecting the transfer of risk or performance implications between the operations.

- Mitigation measures required, including:
  - Specifying the minimum wellhead separation distance being used, if drilling is part of the operation.
  - Addressing regulatory requirements related to operational spacing and fire control requirements, in particular Sections 45 and 47 of the DPR and Section 9.6.15 of the Oil & Gas Activity Operations Manual and determining the safe placement of all required equipment.
  - Verifying adequate egress routes remain following equipment placement.
  - Determining whether any wells or production equipment must be shut in, and if so, describing the method used to secure the wells or equipment.
  - Identifying other permit holders that may be affected by proposed operations.
  - Communication and coordination protocols, including with other permit holders if, applicable.

ERP

A valid Drilling and Completions ERP (also applied to work-over activities) must be submitted to the Commission as required under the Emergency Management Regulation. The ERP must consider and address responsibilities during a SIMOP situation. Please see the Drilling & Initial Completions ERP Guidance Document for more information

SIMOPs Plan Documentation

Where SIMOPs plans are prepared as part of a well intervention, they must be included in the Notice of Operations submission as part of the program. A copy of the SIMOP plan must be kept on site during operations, and personnel participating in the operations must be familiar with its contents.

7.4 Emergency Management Program Requirements

7.4.1 Emergency Management Program and Response Plans

The Oil and Gas Activities Act requires permit holders to prepare and maintain an emergency management program and a response contingency plan (ERP) as prescribed in the Emergency Management Regulation (EMR). The requirements and processes described in the EMR and the Commission's Emergency Management Manual are designed to create a framework for the protection of the public, property and the environment from emergencies arising out of oil and gas activities.

Adequate emergency response procedures and plans must be in place for all wells before well construction, conducting well service operations and/or spudding well.

Response plans should include incident reporting requirements in accordance with the Spill Reporting Regulation and the Commission's Incident Reporting Instructions and Guidelines document.

7.4.2 Notification for Residents in EPZ

Provide notification to residents within hazard planning zone for all wells prior spudding and at rig release.

7.4.3 Emergency Response Planning Meetings

Provide notice to the Commission of emergency response planning meetings within two business days prior to drilling into first oil or gas formation. Notification is made via email to EMP@bcogc.ca.

Chapter 8 Well Activity: Drilling

8. Well Drilling

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.

8.1 Drilling Reporting

8.1.1 Drilling Status Updates

The status update informs the Commission of the drilling status of a well (spud, drilling suspended, drilling resumed and rig release), and is submitted through the Commission's eSubmission portal. The information required in the portal depends on the drilling status change. Status updates must be provided within one business day of a change in drilling status.

For drilling re-entry wells, the supplemental Engineering Data Form accompanying the well permit or well permit amendment will specify what will be deemed as the spud date. Refer to the Re-entries Section of this manual for additional information.

Drilling suspended means a drilling rig has been released, but the drilling of the well is not complete and the permit holder intends to resume drilling within one year of rig release. Examples of this situation include:

- Surface hole rig.

- Switch out rigs for horizontal underbalanced drill.
- Release drilling rig, switch to service rig to penetrate play with air (also considered a drilling operation).
- Drilling ceases due to breakup and will resume when access is restored.
- For a short suspension of drilling operations (for instance, seasonal shutdowns), do not report as drilling suspended. On the Summary Report of Drilling Operations explain the reason for the short suspension (for example: seasonal/holiday shutdown for five days).

Drilling resumed means drilling has resumed after a drilling suspension. The drilling resumed date is usually when the bit commences making new hole.

Rig released means the drilling of the well is complete.

8.1.2 Incident Reporting

Incidents may include, but not limited to; spills, gas release, fire/explosion, kicks of certain level, vandalism or threats and major structural failures. Refer to section 8.2.3 for more information on kick reporting.

All incidents must be reported following the Commission's Incident Reporting Instructions and Guidelines document.

8.1.3 Kick Reporting

All kicks must be reported to the Commission through the eSubmission portal within 24 hours of the occurrence. A follow-up update may be required, depending on the well control situation.

If a kick meets any one of the following criteria, it must be reported as an incident (refer to section 8.2.2 for incident reporting):

- Pit gain of 3 m^3 or greater.
- Casing pressure 85 per cent of maximum allowed casing pressure.
- 50 per cent or more out of hole when kicked.

- Well taking fluid (lost circulation).
- Associated spill.
- General situation deterioration, (for example: leaks, equipment failure, unable to circulate, etc.).

Deterioration of the well control situation should be reported to a Commission Drilling Engineer. If a Commission Drilling Engineer is unavailable or if after hours, call the Commission 24-hour Incident Reporting Line at 1-800-663-3456.

8.1.4 Lost Circulation Reporting

When the lost volume is equal to or greater than 5 m^3 for oil based mud or 10m^3 for water based mud, the lost circulation must be reported through the Commission's eSubmission portal before rig release.

8.1.5 Hole Problem Reporting

For fish in hole, sloughing hole, cementing problem, well control issues or other hole problems where the Commission's assistance is required, contact a Commission Drilling Engineer. If a Commission Drilling Engineer is unavailable or if after hours, call the Commission 24-hour Incident Reporting Line at 1-800-663-3456.

8.2 Well Drilling Data Requirements

8.2.1 Summary Report of Drilling Operations

The summary report of drilling operations must be submitted to the Commission through the eSubmission portal within four business days of rig release or drilling suspended. This includes when the rig is moved or shut down for a period of time, but excludes shutdowns for rig repairs or seasonal holidays.

The Summary Report of Drilling Operations must be completely and accurately filled out. As shown in Table 8A, a summary of formation tops and logs run must accompany the online submission of the Summary Report. This summary must include the following:

- A list of formation tops as picked from the logs. If no open hole logs are run, formation tops may be selected from the measurement while drilling gamma ray (MWD-Gr) log. If there is no MWD-Gr log, formation tops may be selected based on drill cuttings samples.
- Measured depth (MD) and true vertical depth (TVD) must be provided if the well is directional or horizontal.
- List of logs run (including MWD-Gr) with the following information:
    - Log type run (include MWD-Gr if run). The log type must be written out in full - for instance, borehole compensated sonic, not BHC.
    - Run number.
    - Last date run for each run number (finished date).
    - Intervals logged (that is, top depth and bottom depth) for each log including measured depth and true vertical depth, as applicable.
    - Bottom hole temperature (BHT) must be included with the written list of logs run.

Table 8A Formatting for Summary Report of Drilling Operations

Log Type (Name)	Run #	Run End Date	Top Depth (MD)	Bottom Depth (MD)	Top Depth (TVD)	Bottom Depth (TVD)	Bottom Hole Temp (BHT)

Submit the full name of the log, no abbreviations.

For each log, one line of information must be entered.

For wells that have experienced drilling problems not evident from the Summary Report of Drilling Operations, provide a brief point summary in the comments section to explain the problems. For example:

- Drilled to 800 metres, lost fish in hole.
- Fish top at 600 metres, fish bottom at 750 metres.
- Brief description of fish.

- Address issue of potential interzonal communication (if applicable).
- Set plug #1.
- Kicked off plug at depth of 1,215 metres to drill around fish.

For drilling re-entries, provide a brief point summary (in the comments section) of the operations performed if not evident from the Summary Report of Drilling Operations.

For example:

For a basic squeeze of existing perforations, bridge plug set and mill of window in casing to drill horizontally out of cased vertical well.

- Started drilling on surface three metre abandonment plug at 0800 hr 2007-06-15.
- Cement squeezed existing perforations and pressure tested same.
- Set bridge plug at 1,800 metres and whipstock and commenced cutting window

Refer to the Well Data Submission Requirements Manual for file naming and submission requirements.

8.2.2 Directional Survey

A wellbore directional survey is required if:

- Well is horizontally or directionally drilled.
- Surface location of well is outside target area.
- Surface location of well is within the target area but closer to the target boundary than measured depth multiplied by two per cent.

Example (for a well with a 250 meters (m) gas target setback):

Gas well total measured depth = 2,200.0 m.

2,200.0 m X 2% = 44.0 m.

44.0 m + 250.0 m = 294.0 m.

Therefore, if the well surface location is closer than 294 m to the spacing border, a directional survey must be run.

Directional surveys must include:

- Actual surface coordinates of the wellhead.
- Last point on the directional survey must be the total measured depth (TMD) of the well bore. This allows the Commission to link the directional survey with the correct drilling event.
- Cross-section and plan view graphical plots must be included within the PDF file if available.

Directional surveys should be saved and submitted in both TXT and PDF format. The Commission's Directional Survey File Format Guide provides detailed information regarding the submission of directional survey data and the As-Drilled Survey Plan.

Deviation Surveys

Deviation surveys must be made during drilling at intervals not exceeding 150m in depth, unless there are significant wellbore stability problems, in which case a survey may be omitted.

8.2.3 Drillstem Testing

A pressure chart and report containing complete details on fluid recoveries and other pertinent facts for each drillstem test or wire line test taken on a well must be submitted to the Commission within 30 days using eSubmission portal within 30 days of the date on which the test was made.

Useful references for drillstem testing include:

- Worksafe BC's Drillstem Testing Safety Guidelines for drilling and service rigs. Covers safe work guidelines, minimum health and operating standards and personnel qualifications.
- The ESC's IRP Volume #4: Well Testing and Fluid Handling.

8.2.4 Drill Cutting Samples and Core Samples

Drill cutting samples are required at intervals of five metres, beginning at 50 metres measured depth above the shallowest potential reservoir zone and continuing to the total depth of the well.

In accordance with Section 29 of the Drilling and Production Regulation, well samples and cores must be collected during drilling operations and submitted to the Commission within 14 days of rig release. Refer to the Well Data Submission Requirements Manual for further information on related submission process and requirements.

8.2.5 Well Logging

A gamma ray log is required from the ground surface to the total depth of the well.

A neutron log is required from 25 metres below ground level to the base of the surface casing.

Resistivity and porosity logs are required from the base of the surface casing to the total depth of the well.

Wellbores may penetrate up to 20 metres below the lowest objective formation in order to fully log the objective formation.

If a well is part of a multi well pad, only one well needs to have all the above mentioned logging conducted, however, all wells must have a gamma ray log taken from the base of the surface casing to the total depth. This applies for the unconventional zones listed in Schedule 2 of the Drilling and Production Regulation.

8.2.6 Wellsite Geology Report

Well Site Geology Report

Submits a well site geology report through the eSubmission portal portal within 60 days of rig release. Refer to the Commission's Well Data Submission Requirements Manual for more information on submission of wellsite geology reports.

8.2.7 Logging and Sample Waiver

Requests for logging and sample waivers should be made during business hours to the Commission's Petroleum Geology, Resource Stewardship & Major Projects. The request should be submitted to a geologist by email, clearly stating the request and the reason for the request (for example, hole conditions). Refer to the Commission phone list on the website and Petroleum Geology, Resource Stewardship and Major Projects for Contact information. After business hours, the Commission's 24-hour phone line in Fort St. John is 250-794-5200.

8.2.8 Flaring During Drilling

If flaring during drilling operations is necessary, note the following:

- A Notice of Flare must be submitted using the eSubmission Portal for underbalanced drilling. The total flared volume must be reported via Petrinex, in accordance with the usual production volume reporting timeline. In addition, a Well Deliverability Test Report must be submitted through the eSubmission Portal within 60 days.
- For other operations (drillstem testing, managed pressure drilling, kick flaring) advance notification is not required and flared volumes must be reported on the Summary Report of Drilling Operations.
- Estimation is permitted for operations such as kick flaring where accurate measurement of flared volumes is not possible.

To discharge air contaminants pursuant to Section 6(1)(d) of the Oil and Gas Waste Regulation, the permit holder must, at least 15 days prior to commencement of well test flare or incineration of sour gas containing ≥ 5 mole per cent H_2S, in accordance with Section 8 of that regulation, submit dispersion modelling and details of the well test to the satisfaction of the Commission. Submissions must be provided to OGCWaste.Management@bcogc.ca.

8.2.9 As Drilled Wellsite Survey Plan

Section 35(1) of the Drilling and Production Regulation requires the submission of an As-Drilled Survey Plan within 14 days of rig release. The survey plan must be in its original size from the Surveyor (for example, 22" x 34") as a PDF, and show and clearly identify the following information:

- ·Surface and bottom hole location of all drilling events associated with the well
- ·Northing and Easting coordinates, determined using NAD 83
- ·North and East offsets to the nearest corner of the spacing unit, and the reference corner

8.2.10 Well Drilling Site Clean Up (Waste Management)

Permit holders must clean up the well drilling site and restore the surface upon drilling completion and submit a Well Site Clean Up Form and Drilling Waste Report where applicable and detailed in this section. Refer to the Drilling Waste Management Chapter of the oil and gas handbook for more information on drilling waste management.

Well Site Clean Up Form

A Well Site Cleanup Form is required after a well as been drilled to report and inform the Commission of well site and waste management activities.

A Well Site Clean Up Form should include the well name and number, well site sketch drawings and if available, photographs of disturbed areas. Detailed requirements are included on the form. The Commission's Well Site Clean Up Form is available as a word document, downloaded online from the Commission's website. Once completed, the form is mailed to the Commission address as indicated on the form within 60 days of rig release.

Drilling Waste Disposal Report

The Drilling Waste Disposal Summary form should include the permit number, sketches, laboratory results and field analysis and, if available, photographs. Detailed requirements are included in the form. The Drilling Waste Disposal Summary form is submitted using the Commission's eSubmission portal within 90 days of the closing of any earthen pit used to store drilling waste.

8.3 Blowout Prevention: Practices and Procedures

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. This engineering analysis should be submitted as part of the well permit application.

Recommended and industry accepted blowout prevention (BOP) guidelines are included in this section. BOP stack schematics are in Appendix A of this manual.

If an operation is not covered in these guidelines, refer to the applicable industry recommended practices (for example, Energy Safe Canada (ESC) IRPs at www.energysafetycanada.com). Exercise caution when drilling surface holes.

It is prudent to utilize divertors in areas where shallow gas has been encountered or in wildcat areas (areas where little is known with certainty about the subsurface geology) as further explained in Appendix C of this manual.

8.3.1 Blowout Prevention Classifications

Blowout prevention equipment is classified as follows:

1. Class A: to be used from the depth of the surface casing to 1,800 metres true vertical depth.
2. Class B: to be used from a depth of 1,800 metres to 3,000 metres true vertical depth.
3. Class C: to be used from a depth of 3,000 metres to 5,500 metres true vertical depth.
4. Class D: to be used from a depth of 5,500 metres true vertical depth and greater.

8.3.2 Blowout Prevention Pressure Ratings

The minimum pressure rating of blowout prevention equipment must be:

1. 14,000 kPa for Class A equipment.
2. 21,000 kPa for Class B equipment.
3. 34,000 kPa for Class C equipment.
4. 70,000 kPa for Class D equipment.

8.3.3 Other Blowout Prevention Stipulations

When a well is being drilled, blowout prevention equipment must, at all times:

1. Consist of a minimum of one annular preventer and two or more ram preventers; the ram preventers are to be comprised of a blank ram and one or more rams to close off around drill pipe, tubing or casing being used in the well.
2. Be connected to a casing bowl that is equipped with:
3. An upper flange that is an integral part of the casing bowl.

4. For blowout prevention Class A and B, at least one threaded, flanged or studded side outlet with one valve.
5. For blowout prevention Class C and D, two flanged or studded side outlets with two valves.
6. Include steel lines or adequate high pressure hoses connected to the blowout preventer assembly, one or more for bleeding off pressure and one or more for killing the well.
7. Consist of components having a working pressure equal to that of the blowout preventers, except that part of the bleed-off line or lines located downstream from the last control valve on the choke manifold.
8. Have the valve hand wheel assembly in place and securely attached to the valve stem on all valves in the blowout prevention system.
9. Be maintained so that its operation will not be impaired by adverse weather conditions.
10. Hammer unions should not be used in the manifold shack or under the substructure on the primary well control system but can be used in UBD/MPD pressure/flow control system providing the hammer union end connection is welded to the pipe.
11. Conform to the specifications set out in Appendix B.

8.3.4 Blowout Prevention Controls

If hydraulically operated blowout preventers are installed, a clearly marked operating control indicating direction of closure for the annular blowout preventer must be located at least 15 metres from the well.

The control valve regulating the closure of the annular preventer must be free of any valve locking device.

All manual controls for the locking of manual ram type blowout preventers must be installed or readily accessible.

If ram type blowout preventers are used at a cased well, the controls must be attached and be at least five metres from the well.

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

8.3.5 Blowout Prevention Ancillary Equipment

Bleed Off Lines

The bleed off lines referred to above must be:

1. A minimum nominal 76 millimetre diameter of uniform bore.
2. Connected only by welded neck flanges that are perpendicular to the line to which they are attached.
3. Equipped with a gauge connection where well pressures may be measured.
4. Connected to a choke manifold and a mud tank through a mud gas separator.
5. Securely held down and terminated in a slightly downward direction into an earthen pit or flare tank, if the lines are downstream of the choke manifold.

Choke Manifold

The choke manifold referred to above must be located outside the substructure and be readily accessible with safe routes of access and egress.

The choke manifold must provide safe and protected area for the crew to work during well control operations.

The choke manifold referred to above must be designed:

1. To conform with Class A, B, C or D equipment.
2. To permit the flow to be directed through a full opening line or through either of the two lines, each containing an adjustable choke.
3. Equipped with accurate metric pressure gauges to provide drill pipe and casing pressures at the choke manifold once the surface casing is cemented in place.

4. Enclosed by a suitable housing, with adequate heat to prevent freezing.
5. Securely tied down and containing only pipe that is straight or with a 1.57 radian bends (90º) and which is constructed of flanged, studded or welded tees, blank flanged or ball plugged on fluid turns in addition to having bleed off lines.
6. Hammer unions must not be used on main flow lines in the enclosure that houses the choke manifold.

Accumulator

The accumulator system must be:

1. Installed and operated in accordance with the manufacturer's specifications.
2. Connected to the blowout preventers, with lines of equivalent working pressure to the system, and within 5 metres of the well - the lines must be of steel construction unless completely sheathed with adequate fire resistant sleeving.
3. Capable of providing, without recharging, fluid of sufficient volume and pressure to close the annular preventer, close a ram preventer, open the hydraulically operated valve and retain a pressure of 8,400 kPa on the accumulator system.
4. Recharged, within five minutes, by a pressure controlled pump capable of recovering the accumulator pressure drop resulting from closing the annular preventer, closing a ram preventer or opening the hydraulically operated valve.
5. Capable of closing any ram type preventer within 30 seconds.
6. Capable of closing the annular preventer within 60 seconds.
7. Equipped with readily accessible fittings and gauges to determine the precharge pressure of each nitrogen container.

If nitrogen cylinders are used as an emergency pressure source, sufficient usable nitrogen must be available at a minimum pressure of 8,400 kPa to fully close the annular preventer and pipe rams and open the hydraulically operated valve.

Mud Tank Fluid Volume Monitoring Systems

A mud tank fluid volume monitoring system (e.g., Pit Volume Totalizer) must be used during drilling.

The monitoring system must be sufficiently precise to detect a change of ±1 m3 in total pit volume. This typically means each active compartment must have a probe installed.

A drilling fluid level monitoring station with an alarm system must be located at or near the driller's position.

The alarm must include a visual indicator which comes on automatically whenever the alarm is shut off. The indicator must effectively alert the drillers on the floor and in the doghouse (e.g. a highly visible flashing light).

Mud tank volumes must be continuously recorded in the Electronic Drilling Recorder.

A flow line sensor is another monitoring device that can be used in conjunction with an automated mud tank volume monitoring system. The flow line flow sensor cannot be used alone as a monitoring device, but can be installed to augment the automated mud tank volume monitoring system.

Trip Tanks

The drilling mud system must be equipped with a trip tank with the capacity of 5 cubic metres to accurately measure the fluid required to fill the hole while pulling pipe from the well and the trip tank must:

- Be constructed so that the cumulative volume can be reliably and repeatedly read to an accuracy of 0.15 m^3 (150 litres) from the driller's position.
- Be tied into the mud return line.
- Be equipped so that drilling fluid can be transferred into and out of the trip tank.
- Be located in or within 10 metres of the shale shaker end of the mud tank and be readily accessible to afford visual observance of the fluid level.

A diagram of the trip tank and the trip tank volume indicator must be prominently displayed in the control centre (also known as the dog house).

The trip tank volume indicator must specify the trip tank volume and each volume graduation on the scale.

Mud-Gas Separator

Mud gas separators must:

1. Be designed to ensure personnel safety and adequate mud gas separation.
2. Be connected to a securely fastened inlet line and outlet line and the outlet line must:
    3. Be at least one size larger than the inlet line.
    4. Terminate preferably in a flare tank, but also may terminate in an earthen flare pit, at least 50 metres from the well.

Kelly Cock and Stabbing Valve

At all times when a well is being drilled:

1. A valve must be installed in the kelly assembly.
2. A full opening stabbing valve that can be connected to the drill pipe, drill collars or tubing in the well and a device capable of stopping any backflow up the drill string must be provided and must:
    1. Be equipped with removable handles to facilitate handling by two persons.
    2. Be stored in the control centre (dog house) or another satisfactory location where it is readily available for use with the valve in the open position.
    3. Have the valve closing handle attached to the valve holding stand.

Flare Tanks

Flare tanks must:

1. Be constructed of steel with walls of sufficient height to ensure liquid containment during prolonged exposure to fluid flow and extreme heat.
2. Have structural integrity.

3. Have an impingement plate to resist erosion from high-velocity gas, liquids and solids positioned on the flare tank wall directly opposite all flare lines and diverter lines connected to the flare tank.
4. Have a minimum capacity of 8 cubic metres and be appropriately sized for the flow to avoid creating backpressure.
5. Not be covered.
6. Be positioned a minimum distance of 50 metres from the well.
7. Be equipped with a minimum 50.8 mm liquid loading steel line that is connected at all times for the purpose of drawing fluids from the tank, with the connection point of the loading line a minimum of 9 metres from the flare tank.
8. Have degasser vent lines kept separated from the liquid in the flare tank. The vent lines may be laid on the ground next to the flare tank, provided no fire hazard exists.
9. Have a minimum 10 metre setback from vegetation or other potential fire hazards.

Flare Pits

The earthen pit referred to in this document must:

1. Be excavated to a minimum depth of 2 metres.
2. Have side and back walls rising not less than 2 metres above ground level.
3. Be constructed to resist the erosion of a high pressure flow of gas or liquid.
4. Be constructed to contain any liquid.
5. Be used for emergency purposes only.

8.3.6 Testing of Blowout Prevention Equipment

Blowout equipment must be shop serviced and shop tested to its working pressure at least once every three years and test data and maintenance performed must be recorded and made available on request from a Commission official.

Following assembly, all flow line connections that form a part of the blowout prevention system must be inspected by the rig manager and recorded in the daily report.

Prior to drilling out cement from any string of casing, each unit of the blowout prevention equipment must be pressure tested, first to a low pressure of 1,400 kPa and then to a high pressure tests described as follows:

Prior to drilling out surface casing:

1. Each ram preventer to the lesser of the maximum potential shut in pressure (if known), or required BOP Class.
2. Test the annular to the lesser of 70% of the recommended working pressure, recommended working pressure of the wellhead or the ram pressure test as per API 53 or as per the manufacturer's recommended practice.

Prior to drilling out subsequent casing string:

1. Each ram preventer to the lesser of the maximum potential shut in pressure (if known), or required BOP Class.
2. Test the annular to the lesser of 70% of the recommended working pressure or ram pressure test.

A successful pressure test is conducted for 10 minutes with pressure drop less than 10 per cent. If digital pressure test devices are used, a 5 minute test duration is acceptable under below conditions:

Low Pressure test:

1. Final pressure test must be within 90% of the required initial test pressure.
2. The 5 minute test period starts when the pressure has stabilized.
3. A maximum of 5% pressure drop over 5 minutes with a decreasing trend.

High Pressure test:

1. Final pressure test must be within 90% of the required initial test pressure.
2. The 5 minute test period starts when the pressure has stabilized.
3. A maximum of 2% pressure drop over 5 minutes with a decreasing trend.

Analog and electronic pressure gauges shall be used within the manufacturer's specified range and must be calibrated annually in accordance with OEM procedures.

Testing should be done in the direction that pressure may be held during a well control situation.

The line on the low pressure side of the valve must be open during pressure testing.

If a BOP connection is broken within the 30-day test requirement period, only that portion must be retested before drilling resumes. A complete test is still required at 30-day intervals.

Until the equipment passes these tests, further drilling must not proceed.

Casing exposed to drill pipe wear must be tested every 30 days to determine its adequacy for pressure control by either:

1. Running a casing inspection log to determine casing wear.
2. Pressure testing to a pressure not greater than 50 per cent of the burst pressure of the weakest section of the casing, or to the working pressure of the blowout preventers, whichever is less.

Each rig crew must perform a blowout prevention drill every seven days, or as conditions permit in accordance with a Canadian Association of Oilwell Drilling Contractors (CAODC) Well Control Procedure placard (available through the CAODC catalogue) or as outlined by the Energy Safe Canada (ESC) Blowout Prevention Manual.

While pulling pipe from a well, the well permit holder must ensure:

1. The hole is filled with drilling fluid at a frequency that ensures the fluid level in the well bore does not fall below a depth of 30 metres.
2. A permanent record of the drilling fluid volumes required to fill the hole is retained and submitted as part of the daily drilling reports.

While a well is being drilled or tested during drilling operations, the appropriate blowout prevention equipment must be operated daily and, if found to be defective, it must be made serviceable before operations are resumed.

The blowout prevention stack and choke manifold must be pressure tested every 30 days.

Full particulars of all tests must be reported in the daily report, and for a pressure test, the pressure applied and the duration of the test must be recorded.

8.3.7 Personnel Certification

The rig manager (tool push) and the well permit holder's representative at the well site must:

1. Be trained in blowout prevention.
2. Possess a valid Second Line Supervisor's Blowout Prevention certificate issued by Energy Safety Canada (ESC), or a Drilling Well Control Level 4 certificate issued by the International Well Control Forum (IWCF), or a Wellsharp Supervisor certificate issued by the International Association of Drilling Contractors (IADC). A copy of their qualifications must be made available to an official on request.

The driller must:

1. Be trained in blowout prevention.
2. Possess a valid First Line or Second line Supervisor's Blowout Prevention certificate issued by ESC, or a Drilling Well Control Level 3 or Level 4 certificate issued by IWCF, or a Wellsharp Driller or Wellsharp Supervisor certificate issued by IADC.

The CAODC placard or the well permit holder's Well Control Procedures placard must be legible and prominently displayed in the control centre (dog house) at all times.

8.3.8 Blowout Prevention Procedures

The rig crew must have an adequate understanding of and be capable of operating the blowout prevention equipment and the contractor or rig crew must:

1. When requested by a Commission official, test the operation and effectiveness of the blowout prevention equipment in accordance with the CAODC issued Well Control Procedure placard or the Energy Safe Canada (ESC) Blowout Prevention Manual.
2. Record drills performed in the daily drilling reports.

8.3.9 Special Sour Wells

The criteria for a special sour well in B.C. are:

1. Any well from which the maximum potential H_2S release rate is 0.01 m^3/s or greater and less than 0.1 m^3/s and which is located within 500 metres of an urban center.
2. Any well from which the maximum potential H2S release rate is 0.1 m^3/s or greater and less than 0.3 m^3/s and which located within 1.5 kilometres of an urban center.
3. Any well from which the maximum H2S release rate is 0.3 m^3/s or greater and less than 2.0 m^3/s and which is located within five kilometres of an urban center.
4. Any well from which the maximum potential H2S release rate is 2.0 m^3/s or greater.
5. Any other well which the Commission classifies as a special sour well having regard to the maximum potential H2S release rate, the population density, the environment, the sensitivity of the area where the well would be located, and the expected complexities during the drilling phase.

The minimum pressure rating of blowout prevention equipment is the same as defined for an equivalent non-special sour well. Shear blind rams must be used where the calculated emergency planning zone:

1. Intersects the boundaries of an urban centre.

2. Encompasses more than 50 occupied dwellings.
3. Encompasses a portion of a major highway.

The permit holder must notify all residents within the Emergency Planning Zone prior to penetration of the first sour zone and at rig release.

The Commission has fully sanctioned the Energy Safe Canada (ESC)'s IRP Volume #1: Critical Sour Drilling. Refer to this resource for additional information regarding the drilling of special sour wells.

The Commission will evaluate any proposal to drill special sour wells underbalanced on an individual basis. For this type of operation refer to the ESC's IRP Volume #6: Critical Sour Underbalanced Drilling or the Alberta Energy Regulator's Alberta Energy Regulator's Directive 036 Drilling Blowout Prevention Requirements and Procedures and Directive 036 Addendum Drilling Blowout Prevention Requirements and Procedures released in 2015.

A drilling plan is required for a special sour well, refer to the Oil and Gas Activity Application Manual for the drilling plan details.

8.3.10 Special Sour Well Declassification

A permit holder may apply to the Commission to declassify a special sour well after the drilling phase under certain conditions. The declassification of a special sour well will only be considered upon request from a permit holder. Under the following situations, the Commission will consider requests to declassify a special sour well:

1. The original special sour status was determined based on the maximum cumulative drilling H_2S release rate. After the drilling phase, if the maximum completion H_2S release rate does not meet the criteria for special sour well, the special sour status can be removed.
2. The special sour well is a legacy well and the original drilling or completion H_2S release rate information is missing or incomplete. In this case, a new calculation of maximum completion H_2S release rate is required. The maximum completion H_2S release rate must base on the maximum initial Absolute Open Flow (AOF) and maximum H_2S concentration of the subject well or offset wells if the initial completion data from the subject well is not available. If the new calculated

maximum completion H_2S release rate does not meet special sour well criteria, the special sour status can be removed.

3. Any other situations where the Commission determines the well is no longer a special sour well based on the assessment of the updated sour well information.

When a well no longer has special sour status, emergency response information, including any changes to the Emergency Planning Zone (EPZ), must be updated in the applicable EPZ and submitted to the Commission.

A reduced H_2S release rate due to reservoir depletion will not be accepted as a rationale for special sour declassification. The Commission always uses the maximum completion H_2S release rate to determine if the well meets the special sour criteria or not.

Wells associated with acid gas disposal may be classified as Special Sour following disposal activity.

To apply for the declassification of a special sour well, the permit holder must submit a request via email to OGCDrilling.Production@bcogc.ca, including the Sour Well Information Form found in Appendix I of this manual.

8.4 Drilling Practice

8.4.1 Welding of Casing Bowls

Ensure proper welding procedures are followed for the welding of casing bowls. Proper preheating, the maintenance of temperature throughout the welding process, proper cool down techniques and proper rod selection are critical, particularly for special sour wells.

All casing bowl welds performed on wells under the authority of the Commission shall be completed by welders qualified to complete pressure welds in the province of British Columbia. The welds shall be performed in accordance with a qualified ASME Section IX welding procedure. The welding procedure specification and supporting procedure qualification records shall be available on site when casing welding is performed.

Completed casing bowl welds shall be pressure tested in accordance with documented practices established by the permit holder or their representative.

Permit holders are encouraged to take reasonable steps to ensure the integrity of the completed weld which may include monitoring of welding parameters and verification of welder qualifications.

Information on casing bowl welding such as welding procedure, start time, stop time and pressure test results must be recorded on the tour sheet.

8.4.2 Casing and Cementing

Casings must be designed to withstand the maximum load and service condition that can reasonably be expected during the service life of the well.

For protection of potable groundwater aquifers, non-toxic drilling fluids must be used until, in the opinion of a qualified professional (engineer or geoscientist), all porous strata that:

- Are less than 600 metres deep.
- Contain non-saline groundwater that is usable for domestic or agricultural purposes and isolate from the drilling fluid. The depth is referenced as the “base of usable groundwater”. Refer to Appendix E for technical guidance regarding the determination of the “base of usable groundwater”.

Isolation may be achieved by setting and cementing casing. Surface casings must be set a minimum of 25 metres into a competent formation and must be deep enough to support the blowout prevention equipment and to ensure control of expected well pressure.

Surface casings must be cemented full length. If surface casing is not set below the “base of usable groundwater” (as determined by a qualified professional), the next casing string must cemented to surface. Otherwise, intermediate and production casings must be cemented a minimum of 200 metres into the previous string.

Casings where underbalanced drilling is to occur below the shoe should be cemented full length.

Exemptions to specific requirements of Section 18 of the Drilling and Production Regulation may be requested and issued in writing by the Commission under Section 4 of the DPR, and may be necessary for shallow water source wells.

8.4.3 Tripping

Prior to tripping the drill string from the well during overbalanced drilling:

- Drilling fluid density must be adequate to exert a sufficient trip margin ensuring an overbalance of the expected formation pressures so formation fluids do not enter the wellbore.
- A bottoms-up circulation must be conducted or a weighted tripping pill must be pumped.

Flow Checks

When tripping the drill string out of the well, a 10-minute (minimum) flow check must be conducted and recorded in the drilling logbook at the following intervals:

- After pulling approximately the first five per cent of the drill string (measured depth) from the well.
- At approximately the midpoint depth (measured depth) of the well.
- Prior to pulling the last stand of drill pipe and the drill collars from the well.
- After all of the drill string is pulled out of the well.

When tripping the drill string into the well, a 10-minute (minimum) flow check must be conducted and recorded in the drilling logbook at the following intervals:

- After running in the drill collars and the first stand of drill pipe.
- At approximately the midpoint depth (measured depth) of the well.

Prior to conducting a flow check when tripping in or out of the well, the hole must be filled to surface.

Swab and Surge Management

In order to prevent high swab / surge pressures, the drilling fluid must not be too viscous. The best indicator of this property is gel strengths. Ten minute gel strengths should not exceed 30 pascals.

Care shall be exercised to minimize surge/swab pressures by controlling the speed of pipe movements.

Pull the pipe carefully and check for swabbing. In the event of the hole swabbing, the pipe shall be run back to bottom and the hole circulated bottoms up.

Hole Filling

When tripping the drill string out of the well, the wellbore must be filled with drilling fluid at sufficient intervals so that the fluid level in the wellbore does not drop below a depth of 30 m from surface.

Trip Records

When tripping the drill string out of the well:

- Accurate trip records (date, location, depth, type of trip, etc.) must be kept of the theoretical and actual volumes of fluid required to fill the hole.
- The trip records must be kept at the well site until the end of the drilling operation.
- The total calculated and actual (measured) volumes must be recorded in the drilling logbook for each trip.

If the drill string is being circulated while tripping tubulars (i.e., coiled tubing units or top drives), actual hole fill volumes must be recorded at a minimum for every 100 m interval of drill pipe removed and for every 20 m interval of drill collars and recorded on the trip sheet. If tripping resumes without circulating, the trip tank must be used to monitor hole fill volumes. Flow checks must be conducted and recorded at all required intervals with the well in a static condition (pump off).

Tripping with surface pressure

With the presence of annular pressure there is the potential hazard of a pipe light condition developing. Pipe light occurs when the well head pressure acting over the cross-sectional area being sealed against exceeds the effective weight of the pipe in the hole. For tripping procedures, refer to IRP Volume 22: Underbalanced Drilling And managed Pressure Drilling Operations Using Jointed Pipe.

If tripping pipe with positive wellhead pressure is required, snubbing may be necessary. Refer to IRP Volume 15: Snubbing Operations.

8.4.4 Well ballooning management

While pumps are on, if Equivalent Circulating Density (ECD) exceeds formation fracture, micro fractures are created and drilling mud will lose into small induced formation fractures. The micro fractures can be propagated and it may cause a lot of mud volume losses down hole. Micro fracture will not cause severe losses or totally losses. When pumps are off, the ECD will reduce because annular pressure loss becomes zero. The induced micro fractures will close and the drilling mud will flow back into a wellbore. The ballooning phenomenon may be confused with a kick.

Recommended drilling practices:

- Bring pumps up slowly and stage-by-stage increment.
- Slowly rotate drill string for few seconds to break gel prior to slowly bringing pumps up to speed.
- Trying not to lose fluid or to minimize drilling mud loss into formation.
- All well flows must initially be treated as a kick.
- Ballooning can only be confirmed after circulating bottoms-up maintaining constant BHP via the choke to confirm influx fluid type.

8.4.5 Stick Diagram

A Stick diagram is a well data information sheet specific to the drilling operation of a well (obtained from researching offset well records). It must provide the appropriate onsite personnel (e.g., permit holder, rig manager, driller) with sufficient well control information to drill the well and must be posted in the doghouse.

The stick diagram must include, as a minimum, the following information:

- Geological tops.
- Anticipated formation pressures and mud weights required to control them.
- Potential problem zones (e.g., lost circulation, water flows, gas flows).
- Abnormal pressured zones (e.g., reservoir pressure maintenance).
- Potential H_2S zones.
- Other well occurrence information.

The appropriate on-site personnel must review and understand the information provided in the STICK diagram prior to drilling out the surface casing shoe or prior to the commencement of drilling operations with a diverter system.

8.4.6 Managed Pressure Drilling and Underbalanced Drilling

Managed Pressure Drilling (MPD)

Managed pressure drilling (MPD) is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. Combining annular flowing friction, fluid properties and density, circulation rate and wellhead pressures, MPD maintains bottomhole pressure above pore pressure, discouraging reservoir inflow.

Underbalanced Drilling (UBD)

Underbalanced drilling (UBD) is a drilling procedure whereby manipulating fluid density / properties, circulation rates and wellhead pressures, bottomhole pressure is kept intentionally below formation pressure, allowing formation fluid influx into the wellbore.

For MPD/UBD practices, refer to [IRP Volume 22: Underbalanced Drilling And managed Pressure Drilling Operations Using Jointed Pipe.]

8.4.7 Plug backs and Abandonments

Notification or approval is not required prior to conducting open-hole plug backs or abandonments. Permit holders must ensure that cementing is conducted in a manner that ensures hydraulic isolation between porous zones and the tops of all cement plugs must be verified. If there is any uncertainty regarding the adequacy of a plugging program, contact the Commission's Drilling and Production Department to discuss the program.

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 Commission 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 Commission 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 Commission’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 H2S 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 Commission's Notice of Operations and Completion / Workover Report Reference Guide. The NOO is to be submitted electronically through the eSubmission portal on the Commission'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 Commission'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 OGAA.

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 Commission’s web site.

The Notification of Commingled Well Production form must be submitted to the Commission 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 rigrelease date.
- For completion and workover activity, the date of last activity is defined as the completion date.

A permit holder may apply to the Commission 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 Commission. 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 Commission 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 Commission.

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 Commission Drilling and Production department for an extension of a deadline.

The following tables describe the Commission'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 Commission 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 Commission 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

[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.

			non-freezing 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 Commission'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 Commission's Supplementary Information for Water Source Wells document.

9.4 Suspended Well Reporting Requirements

9.4.1 Commission Reporting

Well Suspensions

A Well Suspension / Inspection Report must be submitted to the Commission'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 Commission 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 Commission'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 Commission 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 Commission'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 Commission. 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 Commission at the time the work was completed, the Commission 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 Commission 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 Commission 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 Commission'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 Commission and discuss with the Commission 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.	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.

The Commission 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 Commission's Inter-Wellbore Communication Report Form (located on the Commission'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 Commission'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 Commission 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 Commission 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 Commission 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 Commission 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 Commission 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 Commission as described above.

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

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

The Commission 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 Commission'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 of July 1, 2021, Section 52.11 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 Commission.

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.

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 H2S in a SCVF can be confirmed by the use of a personal monitor, onsite H2S 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 Commission 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 Commission 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 Commission 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 Commission. 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 Commission inspection must be reported.

The Commission 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 Commission on request.

All reporting of SCVF test results must be done via the Commission'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

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 Commission as soon as possible to discuss repair or management requirements.

9.7.5 Surface Casing Vent Flow Production

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 Commission 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 Commission determines a safety or environmental hazard exists.

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 Commission 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 Commission 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 Commission 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 Commission'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 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.

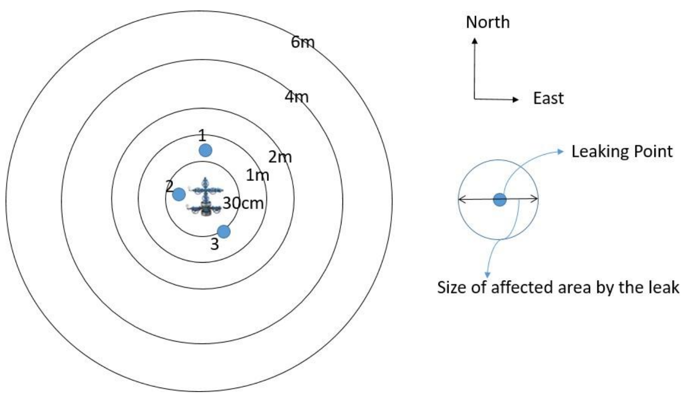
- Collect the gas sample for lab analysis if this was not done before or there is a significant change on the GM.

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.

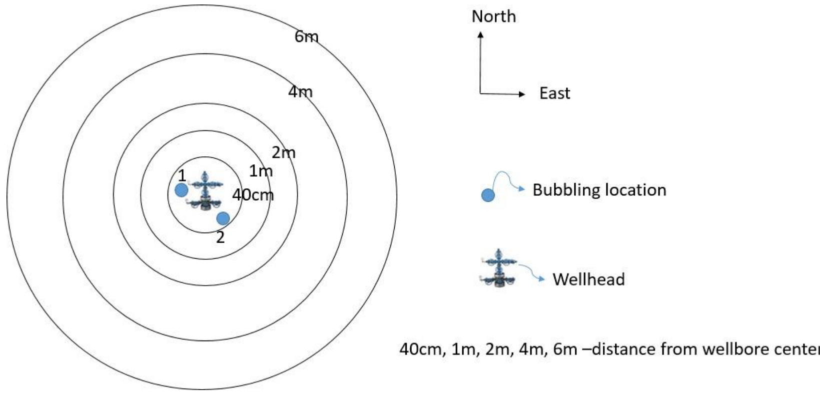
- In case that methane is present at a 6 m distance from the wellbore center, the test must be extended by appropriate distance intervals over an area sufficient to delineate the extent of gas at ground surface.
- In case that the well is located in an area covered by water,
  - record bubbling locations 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 Commission 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.
- Calibrated monitor or other instrument capable of detecting hydrocarbons at on ppm or per cent if concentrations are above 10,000 ppm.
- 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 Commission.

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 Commission, for example to allow testing during frost-free conditions. Based on review of the risk assessment report, the Commission 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 Commission.

- 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 Commission'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 BC OGC 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 Commission'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: BC OGC 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 H2S	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	
Groundwate r	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 Commission's website

All submissions made to the Commission 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 Commission of anticipated repair work must be completed via a Notice of Operations submitted via the Commission's eSubmission porta. Specific requirements may be subject to review by the Commission'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 Commission 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 Commission'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 Commission'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 OGAA 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 Commission 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 behaviour 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
- Brdige 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 behaviour. 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.

Chapter 10 Well Activity: Production and Injection Disposal

10. Well Activity: Production and Injection Disposal

Permit holders must complete metering and testing requirements and submit data as part of ongoing production stage. This section describes the requirements and procedures for each well type including water source, oil, gas and injection/disposal well.

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.

10.1 Notice of Commencement of Operations

New completion events must be reported to the Commission through the eSubmission Portal. These events must be reported in order for the corresponding well event to populate in Petrinex. Completion events must be reporting where the following operations occurred at a well:

- Testing operations at a well prior to its being tied in to a gas gathering system.
- Initial commencement of production.
- Initial commencement of injection or disposal.
- Suspension of production.
- Suspension of injection or disposal.
- Resumption of production.

- Resumption of injection or disposal.

A separate completion event must be reported for each well or completed zone within a well.

10.2 Concurrent Production

Concurrent production is the controlled, simultaneous production of an oil accumulation and its associated gas cap. Concurrent production may typically be approved for “gassy” oil pools, without defined gas cap wells, where the producing gas-oil ratio significantly exceeds the solution gas-oil ratio. Concurrent production requires a Special Project order under Section 75 of the Oil and Gas Activities Act. Refer to the Commission’s Concurrent Production Application Guideline for further information on application process and requirements.

10.3 Reservoir Pressure Survey Test Reports

Section 73 Drilling and Production Regulation defines the requirements for obtaining static bottom hole reservoir pressure measurements. All static bottom hole pressures must be reported to the Commission within 60 days after the date on which the pressures were measured. Refer to the Commission’s Well Data Submission Requirements Manual and Well Testing and Reporting Requirements document for further information.

Under Section 4(1)(z) of the Drilling and Production Regulation, the Commission may grant a well operator exemption from initial or annual pool pressure testing requirements. See the Commission’s Application Guideline for Exemption of Initial or Annual Pool Pressure Testing Requirements document for more information.

10.4 Oil Well

Sections 54 though 62, 69 and 71 of the Drilling and Production Regulation provide regulatory requirements for production from oil wells.

Oil Production Analysis

Section 62 of the Drilling and Production Regulation - Well Data Submission within six months of initial production date, a crude oil sample from each producing formation must be taken and analyzed. Results of component analysis must be submitted to the eSubmission portal within 60 days of test/sampling.

Overproduction of Oil Reporting

Section 61 of the Drilling and Production Regulation references overproduction of oil reporting requirements and the Commission's Production Allowable Report Instructions and Examples provides instruction on calculation and reporting methodology, with examples.

Pressure Maintenance and Improved Recovery

Water, natural gas or a fluid such as CO_2 may be injected into an oil pool to achieve higher oil recovery than by primary depletion. Prior to these operations being carried out, a waterflood, gas injection or enhanced oil recovery (EOR) project approval must be issued by the Commission as a Special Project under Section 75 of the Oil and Gas Activities Act. Refer to the Commission's Pressure Maintenance or Improved Recovery Project Application Guideline for further information on application process and requirements.

Additional operational requirements for water injection well service can be found in the Water Service Well Summary Information.

10.5 Gas Well

Sections 63 through 67, 70 and 71 of the Drilling and Production Regulation provide regulatory requirements for production from gas wells.

Gas Production Analysis

Section 67 of the Drilling and Production Regulation - Within six months of initial production date, a natural gas sample must be taken and analyzed from each producing formation. Results of the component analysis must be submitted within 60 days of test/sampling to the eSubmission portal.

Overproduction of Gas Reporting

Section 66 of the Drilling and Production Regulation references overproduction of gas reporting requirements and the Commission's Annual Gas Allowable Form is used for reporting.

10.6 Water Source Well

Production from a water source well must be carried out in accordance with Section 72 of the Drilling and Production Regulation. In addition, the Commission's Supplementary Information for Water Source Wells details requirements for meeting the expectations of Section 72.

10.7 Injection Disposal Well

There are several waste streams associated with oil and gas production and processing. These include saline produced water, hydraulic fracturing flowback water as well as acid gas (H_2S and CO_2). An effective and efficient method of managing these waste streams is to re-inject them into depleted hydrocarbon reservoirs or deep saline aquifers. The Commission maintains several documents that provide information related to disposal well operations. Refer to the following Commission documents for description of operational requirements:

- Acid Gas Disposal Well Application Guideline.
- Acid Gas Disposal Well Summary Document.
- Application Guideline for Deep Well Disposal of Produced Water / Non-Hazardous Waste.
- Water Service Well Summary Information.

While operating injection or disposal wells, permit holders must submit an Injection/Disposal statement to the eSubmission portal no later than 25 days after the end of month in which the activity occurred.

Chapter 11 Pipeline Activity

11. Pipeline Activity

The pipeline activity section of this manual provides operating guidelines for regulatory requirements throughout the operations life cycle of the permitted activity. Construction activities are discussed in Section 4 of this manual. Associated oil and gas activities, if required in addition to the oil and gas activity permit, are touched on in Section 3.1 of this manual.

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.

11.1 Pipeline Permitted Activities

All permit holders are ultimately responsible for ensuring they understand and meet all legal and regulatory requirements of the permit, including all conditions attached to the permit. If an exemption is requested from regulatory requirements, an exemption must be prepared at the time of application. Permit holders must contact the Commission prior to commencing construction or operations if the adherence to the permitted activity cannot be met. The Commission may be able to provide further guidance and clarification.

11.1.1 Pipelines Defined

Pipelines are an oil and gas activity as defined in the Oil and Gas Activities Act as:

Piping through which any of the following is conveyed:

a) Petroleum or natural gas.

b) Water produced in relation to the production of petroleum or natural gas or conveyed to or from a facility for disposal into a pool or storage reservoir.

c) Solids.

d) Substances prescribed in Section 133(2)(v) of the Petroleum and Natural Gas Act.

e) Other prescribed substances.

And includes installations and facilities associated with the piping, but does not include:

f) Piping used to transmit natural gas at less than 700 kilopascals (kPa) to consumers by a gas utility as defined in the Gas Utility Act.

g) Well head.

h) Anything else prescribed.

Additionally, the following substances are prescribed in OGAA for the purposes of paragraph (e) above:

- Water or steam used for geothermal activities or oil and gas activities.
- Carbon dioxide.
- Liquid hydrocarbons.

And the following is prescribed for the purposes of paragraph (h) above

- Pipelines used in a gas distribution main, as defined in regulations under the Safety Standards Act.

Temporary Above-ground Lines for Freshwater

Temporary above-ground lines designed to transport fresh water are not within the definition of a pipeline and authorized by the Commission as associated oil and gas activity; therefore, not discussed in this section.

Canada Energy Regulator (CER) Pipelines

Land Act authorizations related to pipelines are regulated under the Canada Energy Regulator (CER) Act. The authorizations differ as they are not related to an OGAA activity. To maintain this distinction, separate application types have been created for CER related authorizations and detailed in the Commission's Oil and Gas Activity Application Manual. CER Pipeline operations are not discussed in this section.

11.1.2 Regulatory Requirements

Pipelines must meet the design and operational requirements outlined in the Oil and Gas Activities Act (OGAA), the Pipeline Regulation and the Environmental Protection and Management Regulation (EPMR).

Of particular note, as required under Section 3 of the Pipeline Regulation:

- Every permit holder designing, constructing, operating, maintaining or abandoning pipeline infrastructure in British Columbia must follow the most current version of CSA Z662, including Annex A and Annex N.

11.1.3 Guidance Requirements

Pipeline activities should meet guidance recommendations in the following documents:

- Environmental Protection and Management Guideline.
- British Columbia Common Ground Alliance's Recommended Practice for Damage Prevention Programs.
- BC One Call website.

11.2 Pipeline Construction Requirements

Permit holders must complete a Notice of Construction Start and specific construction requirements as detailed in Chapter 4 of this manual.

Prior to beginning construction submit a Notice of Construction Start in KERMIT. Notices must be submitted prior to commencement of land clearing and/or the set-up of equipment on location and at least two days before construction is to begin.

11.2.1 Pipeline Crossing Distances

The permit holder must not carry out a prescribed activity within 30 m of a pipeline unless carried out in accordance with the Pipeline Crossings Regulation. BC One Call must be contacted in order to confirm if there are one or more pipelines within 30 m of the proposed ground disturbance. If confirmed, each pipeline permit holder must be contacted to establish the pipeline/s is at least 10 m away from the proposed site of the activity.

If the pipeline operator confirms the proposed activity is within 10 m of the pipeline, the pipeline operator can provide specific written permission regarding the ground activity and rules to abide to if the activity is permitted to proceed. The pipeline operator may establish permissions that extend beyond 10 m from the pipeline.

More information is available in Land Owner's Information Guide on the Commission's website.

11.2.2 Crossing Public Rights of Way

Where a pipeline is to be constructed across a public right of way, the permit holder must give notice to the owner or authority responsible for the public right of way at least five days prior to beginning construction or other work. Further, the permit holder must make all reasonable efforts to restore any infrastructure damaged or removed during pipeline construction.

11.2.3 Notice of Pressure Test for Pipelines

Section 4(1) of the Pipeline Regulation states:

- A notice of pressure test must be submitted to the Commission two days prior to the start of a pipeline pressure test.

The Commission uses the information in the notice of pressure test to coordinate oversight of pressure testing by a Commission Inspector, if required. All pipeline pressure tests, including those without an associated application or amendment requires notification to the Commission.

Notice of pressure test may be either a shop and/or a field test as follows:

- Shop tests are pressure tests conducted in the shop, usually used during repairs or modifications of short segments. Generally, shop tests are used for pre-testing pipe.
- Field tests are pressure tests conducted on site during construction or maintenance activities.

Notices of pressure tests associated with an application in AMS or in Kermit, must be submitted online using KERMIT.

Changes to Pressure Test Plans

Notify the Commission by email (OGCPipelines.Facilities@bcogc.ca) of any changes to the approved/amended pressure test plan. This includes changes to the medium, hold times, and/or changing the type of test (shop/field). Include a detailed reason for the change(s). An amendment may be required.

Pressure Testing existing pipelines

Notify the Commission by email (OGCPipelines.Facilities@bcogc.ca) 48hrs prior to pressure testing an existing pipeline when there are no associated amendment applications or NOIs. Include all details of the pressure test including medium, hold times, and attach an Engineering Assessment as required by clause 10.3.9 of CSAZ662.

Pneumatic Testing

Pneumatic testing must be approved as part of the application or an amendment. If pneumatic testing is not part of the permit, then justification for a variance must be submitted to the Commission prior to a notice of pressure test. Submit an explanation of why pneumatic testing is required, calculations and the full pneumatic test procedure specific to the segment. Submission is by email to the Commission's Pipeline Engineer OGCPipelines.Facilities@bcogc.ca.

Other changes to pressure test plans (e.g. minimum pressure) may also require approval by the Commission. Contact the Commission's Pipeline Engineering department for clarification.

11.2.4 Restoration of Land

Section 5 of the Pipeline Regulation states:

- Land disturbed during pipeline construction must be restored as soon as practicable during pipeline construction.
- Land not restored during construction must be restored post construction as soon as possible.

Section 3.11 of this manual provides further information and links on land restoration.

11.2.5 Survey Plan Submission

Section 24 of the General Regulation states:

- A pipeline permit holder must submit to the Commission a survey plan for all portions of pipeline right of way on Crown land within 16 months of completion of construction.

The survey plan is used to issue a statutory right of way tenure over the pipeline right of way. The Commission's Permit Operations Administration manual provides details on the statutory right of way process.

11.2.6 Pipeline Changes During Construction

During construction should engineering changes deviate from the pipeline permit, an amendment must be submitted prior to construction of any portion of the pipeline affected. This is required by Section 21 of OGAA.

Alternatively, changes deviating from the permit and identified with an as-built (and not an amendment) may include:

- Changes of length less than 50 metres, provided no new land is required, and end points are as applied for.
- Changes to material standards provided they meet CSAZ662 standards.
- Change in CO^2 content.
- Small changes in design temperature, provided the temperature is within the coating limits.
- Aboveground changes in piping components such as adding/removing valves and fittings are acceptable provided the scope of the pipeline change doesn't impact anything referenced in the permit and the materials are specified in the appurtenance design.
- Changes in material grade and changes in wall thickness as long as they meet the requirements of CSAZ662; the reviewing engineer may require an amendment if the change is significant. ie a significant change maybe if the MOP corresponds to an increase in the % of specified minimum yield strength.
- Changes to cathodic protection and cathodic type.
- Changes to depth of cover as long as the change meets CSA Z662.

11.3 Pipeline Pre-Operational Requirements

11.3.1 Emergency Management Program Response Plans

Permit holders must prepare and maintain an emergency response program and a response contingency plan as prescribed in the Emergency Management Regulation (EMR). In addition to the requirements and processes described in the EMR and the Commission's Emergency Management Manual, response plans for pipelines should include incident reporting requirements in accordance with the Spill Reporting Regulation.

Incident Reporting

In addition to the incident reporting guidelines in Section 3.3 of this manual, when filing for a repair or replacement after an incident, a permit holder can do the following:

- Submit an NOI of Repair/Replace Pipeline (in-kind) for repairing and replacing a pipeline with the same material specification.
- Submit a Pipeline Amendment for Repair/Replace pipeline with different material specification (not in-kind).

11.3.2 Asset Integrity Management

Pipeline Integrity Management Programs (IMPs) provide a systematic approach for assuring pipeline integrity throughout the entire pipeline life cycle including planning, design, construction, operation, maintenance and abandonment.

As required under Section 7 of the Pipeline Regulation (PR), every permit holder planning, designing, constructing, operating, maintaining or abandoning pipeline infrastructure within the province of British Columbia must have fully developed and implemented IMPs. To facilitate compliance assurance, all permit holders must act in accordance with the most current version of CSA Z662 standard.

The Commission's compliance assurance protocol is based on CSA Z662 and the guidelines outlined in Annex A and Annex N. The Commission's Compliance Assurance Protocol Integrity Management Programs for Pipeline Systems and the Oil and Gas Activity Application Manual provides more information on integrity management programs for pipelines.

11.3.3 Notice of Leave to Open

The Notice of Leave to Open affirms the pipeline has been constructed as permitted and to CSA standards, and all technical information contained in the notice is accurate and complete.

The Notice of Leave to Open also notifies the Commission of its intention to operate a pipeline, prior to beginning operations.

The Notice of Leave to Open must be submitted prior to commissioning any pipeline project or segment. To avoid delays at the leave to open stage, As-Built plans are not required until three (3) months after the Leave To Open. All NDI, including tie-in welds, must be completed and the Emergency Response Plan filed prior to submitting the Leave to Open. Results of pressure tests must be submitted with LTO.

The Leave to Open is submitted through KERMIT. The operation of the pipeline may commence as soon as the Leave to Open is submitted in KERMIT.

11.3.4 As-built Submission Requirements for Pipelines

As-built specifications, data and drawings **must** be submitted within three months (3 months) of construction completion.

The As-built submission provides the Commission with information about the technical aspects of the constructed pipeline as is a requirement of the permit.

Submit within the 3 month mark through KERMIT.

Information required in As-built Submissions

All As-built submissions require inclusion of original process and instrumentation diagrams (P&ID), plot plans and flow schematics. P&IDs must be signed, dated, and sealed by a Professional Engineer and submitted with the As-built form. “Typical” drawings are not acceptable. As-built submissions should include the following attachments:

- Index (optional).
- Legend (may be included within the P&ID package).
- P&ID (see Appendix E for minimum P&ID expectations):
    - Include all pipeline installations, with the exact locations.
    - Include the start and end points of each segment, properly labeled.

    - Must be signed, dated, and sealed by a professional engineer licensed or registered under the Engineers and Geoscientists Act.
- Plot plan (optional).
- Flow schematic (optional).
- Tie-in Schematics of emergency shutdown (ESD) valves with set points.
- Tie-in to all pressure control devices must be shown.
- System map showing isolation valve, rectifiers, and CP test site locations.

Submissions are reviewed for completeness and may be declined for the following reasons:

- Incomplete line specification details.
- Missing engineer seal, date, and signature or engineer is not registered within the province of B.C.
- Missing legend indicating the symbols used.
- Missing attachments.
- Incomplete or missing endpoints/ segment splits.
- Incomplete appurtenances or missing information/details on said appurtenances.
- Incomplete or missing location.
- Incomplete or incorrect labels.
- Unclear lines within As-Built or unapparent which lines are the ones to review.
- Clarification required (for example sour pig barrel not showing release going to flare, but appears to go to atmosphere).
- Missing isolation valve, pressure control, or ESD valves from system map.
- Mismatched as-Built from permitted application, with the exception of those changes indicated as acceptable as part of an As-Built above.

11.4 Pipeline Reporting Requirements

Regulatory Reporting: KERMIT

All reporting functions for pipelines are completed through KERMIT. Access to KERMIT and documentation for using the KERMIT system is found on the Online Services page of the Commission's website.

11.5 Notice of Intent

The Notice of Intent allows for the reporting of operational changes, integrity activities and modifications or repairs to existing pipelines requiring no new acquisition of land, or additional surface tenures, and no modifications to the pipeline permit.

For any Notice of Intent requiring an engineering assessment, engineering assessments must be performed and documented to the standards outlined in CSA Z662. Engineering Assessments are considered engineering documents and, as per Section 20(9) of the Engineers and Geoscientists Act, must be sealed by a professional engineer licensed in the province of British Columbia.

A pipeline Notice of Intent matrix is located in Section 11.5.11 of this manual, and shows all pipeline activities which are submitted through the Notice of Intent process. It also indicates all other required submissions through to completion of the activity.

The Notice of Intent types and requirements are defined below.

11.5.1 NOI: Change CSA Z662 Class Location

Changing the class location is required when a pipeline; originally designed for a specific CSA class location, experiences demographical changes such as dwelling encroachments and/or development that will reclassify the pipeline. For definitions and explanations of class locations refer to CSA Z662 Clause 4.3.2 through 4.3.4.

Attachments to this type of NOI should include a rationale supporting the suitability of the pipe to operate at the proposed class location without modifications, and an Engineering Assessment if required by CSA Z662 clause 10.7.1.

11.5.2 NOI: Decrease Maximum Operating Pressure (upstream)

Decreasing the maximum operating pressure (MOP) will not change the design pressure, but will reduce the maximum operating pressure of the line. It may be used when: a) the current maximum operating pressure can no longer be safely sustained, b) field pressures have changed and the permit holder wants to decrease the maximum operating pressure to match the field pressures, or c) a reduction is necessary to ensure the Emergency Planning Zone remains within a specific distance.

If a permit holder wants to raise the MOP on lines after a decrease, a pipeline permit engineering amendment is required see Section 11.6 of this manual for more information.

Attachments to this NOI type should include documentation / drawings with the reasons for maximum operating pressure decrease, what type of pressure protection measures taken for the lower MOP, and facility / project number the line is connected.

11.5.3 NOI: Decrease Maximum Operating Pressure (downstream)

Decreasing the maximum operating pressure will not change the design pressure but will reduce the maximum operating pressure of the line. It is also used when the pipeline is being taken to pressures that are below the Commission's jurisdictional pressure of 700kPa.

If a permit holder wants to raise the MOP on lines after a decrease, a pipeline permit engineering amendment and a full engineering assessment is required as outlined in Section 11.6 of this manual.

Attachments to this NOI type should include documentation / drawings of the reasons for maximum operating pressure decrease, what type of protection measures taken for the lower MOP and facility / project numbers the line is connected.

11.5.4 Repair or Replace pipeline (in-kind)

A repair to, or replacement of, a pipeline (segment) is a procedure which maintains integrity, and does not change design. The material replacing the existing segment may be one grade different and may have up to a ten per cent difference in wall thickness as long as the per cent stress at MOP does not increase.

A repair replace in Kind NOI is required for the installation of a repair sleeve or if the pipeline will be physically cut into, including repair or replacement of pipeline installations. A Notice of Construction Start, Notice of Pressure Test and a Leave to Open are also required if pressure welding and/or pressure testing is conducted.

For installation of a repair sleeve only, the NOI may be submitted within 30 days of the installation of the repair sleeve. A Notice of Construction Start, Notice of Pressure Test and a Leave to Open are not required.

Attachments to this type of NOI should include:

- the work locations (UTM NAD 83 CSRS),
- a description of all work including length of the repair, descriptions of modifications and/or repairs and replacing material (Type, OD and Wall thickness),
- the reason for repair or replacement (i.e. corrosion, crack, dent),
- details regarding the dimensions and/or severity of any applicable imperfection or defect
- if associated with a direct inspection from ILI, reference to the associated Dig Identification, and
- indication if any follow-up analysis such as metallurgical testing will be completed.

Please Note:

NOIs for a repair or replacement pipeline must indicate whether the repair or replacement is due to maintenance or an incident. If it is due to an incident, the DGIR number (Provincial Emergency Program tracking number) given when the incident was reported must be included. For both incident and maintenance NOIs, a schematic showing where along the segment the work will take place must be included. If this information is missing, the submission will be declined.

11.5.5 Integrity Activities

Integrity activities include inline inspection for integrity condition assessment and integrity direct inspection (dig) programs. NOIs for integrity activities must be submitted 30 days after completion of the annual program (i.e. digs completed within a calendar year or receipt of ILI results). One NOI should be submitted for each pipeline project.

For inline inspection, attachments to the NOI should include:

- The pipeline and associated segments included in the ILI including total length to be inspected;
- ILI launch location (UTM Coordinates) and ILI receive location (UTM coordinates);
- The date of the ILI;
- The Integrity Threats being assessed (corrosion, cracking, strain, etc.)
- the type of ILI technology being run (i.e. Magnetic Flux Leakage, Geo, Ultrasonic Crack Detection, etc.);
- the Vendor of the ILI tool; and
- a summary of the results of the ILI (executive summary).

For integrity digs, attachments to the NOI should include:

- Dig Identification (i.e. Unique ID, ILI Odometer, Girth Weld)
- Pipeline Project Number and associated segment as applicable;
- UTM coordinates of each dig site;
- Length of each dig site;
- Target feature type(s) for each site (i.e. Dent, Corrosion, Crack-like, etc); and
- Date dig was performed for each site.

Please Note:

One NOI should be submitted per pipeline project for the annual dig program. A unique NOI is not required for each dig.

11.5.6 Install/replace/remove farm tap

A farm tap is an installation which taps natural gas from a pipeline regulated by the Commission, it does not require any right of way, and uses a single or double regulating unit to reduce pressure below 700 kPa before transmitting natural gas to consumers. Typically a farm tap ties into a single domestic gas line, less than 50 metre in length and less than 35 mm outer diameter. For lines outside these specifications, written permission is required from the Commission to apply as a farm tap. A permit holder may email OGCPipelines.facilities@bcogc.ca and attach the written permission from the Commission to the farm tap NOI.

Farm taps are considered 'Pipeline Installations in KERMIT. However, unlike other installations they can still be added, deleted or modified via an NOI. The addition, repair, replacement, or removal of a Farm Tap are all downstream Notices of Intent.

Attachments to this type of NOI should include all relevant schematics and a map showing the location of the farm tap.

11.5.7 NOI: Deactivate / Abandon a Pipeline

The Notice of Intent (NOI) to deactivate a pipeline should be submitted to deactivate an active pipeline, abandon an already deactivated pipeline, or to abandon an active pipeline. The NOI should be submitted immediately following the completed fieldwork.

Deactivation

Section 9 of the Pipeline Regulation requires that the pipeline should be deactivated according to CSA Z662 and notified to the Commission within 18 months after the date on which a permit holder's permitted pipeline is deemed to be inactive the last day it conveyed product).

A permit holder may submit a plan for resuming the transportation of fluids through the pipeline or a plan for completing the deactivation after the 18 month period. These plans should be submitted and received the approval before the end of the 18 month period.

Plans for resumption or deactivation after 18 months, should be submitted to intergrityengineering@bcogc.ca.

The Notice of Intent for deactivating a pipeline must include documentation providing a detailed scope of work and the following information:

- Reason for pipeline deactivation.
- Method of isolation.
- Pressure left on the pipeline.
- Medium used to fill the pipeline and the effects of the medium on the integrity of the pipeline.
- Method being used for internal and external corrosion monitoring and mitigation.
- Planned length of deactivation.
- Planned maintenance activities on the pipeline during the deactivation time frame.
- Field map showing the wells and pipelines in the area and which are active, suspended/deactivated and abandoned. This can be a screenshot of a map / drawing showing the pipelines.
- Deactivation form completed by the field officer at the end of the work.

Abandonment

Abandonment applies to abandoned in the ground pipelines or pipelines which had being removed. Pipelines should be abandoned in place in accordance with CSAZ662.

The permit holder must also contact the BC Assessment Branch in reference to removal from the tax roll.

For lines being abandoned in the ground, the abandoned line must remain registered with BC One Call and the Commission recommends that signage be removed once pipelines are abandoned. However, if operators deem signage appropriate, as per Cl 10.16.3 of CSA Z662, then it must be maintained and not pose a hazard. The company remains liable for the environmental impacts of the pipeline remaining in the ground.

Registration with BC One Call is not required if the line is being removed, but the permit holder is responsible for restoring the land after the removal.

When abandoning a line, a permit holder will be required to agree that all installations exclusive to the pipeline segment being abandoned will be removed.

The Notice of Intent for abandon a pipeline must include documentation providing a detailed scope of work and the following information:

- Description of work covering Section 10.16 of CSA Z662
- A drawing showing the portions of the pipeline abandoned in place.

For abandoned lines removed in their entirety, the description page must include the removal and the date of the removal.

If the pipeline is on private land, details about landowner awareness about the abandonment.

11.5.8 NOI: Reactivate a Pipeline

To reactivate a pipeline from a deactivated state, a permit holder must follow the requirements of the latest edition of CSA Z662 and submit an NOI to reactivate.

If the pipeline will be resuming production, an engineering assessment is required, and a pressure test may be required as part of the assessment. If a pressure test is required, a pressure test plan may be submitted with the NOI to reactivate.

If the permit holder is planning to change the pipeline while reactivating, an amendment should be submitted through AMS.

11.5.9 NOI: Modify Data

Discrepancies in pipeline specifications or details in KERMIT can be corrected or completed through the Modify Data Notice of Intent. Supporting documentation for the change should be included with the NOI.

This does not apply to data changes that affect the permit approval, or any data change that should be addressed with an amendment.

Modify data NOI should be submitted to remove the approved risers and any other pipeline installations from the pipeline segment. Modify data NOI to remove the installations should include a P&ID.

11.5.10 Notification for Pipeline Change

Effective July 10, 2023, the notification permission clause will be included in all new pipeline permits. It will also be added to all pipeline amendments and new permits that are issued because of a segment split due to a transfer or reconciliation. This is being implemented to provide Permit holders a means of notifying the Regulator of administrative and/or pipeline changes where an amendment is not necessary. Permit holders must ensure the notification permission has been added to each permit prior to submitting a notification for pipeline change through a historical pipeline submission or eSubmission.

Pipeline changes made to adjust the outside diameter, adjust the wall thickness, change the pipe grade, change pipeline product in a manner that conforms to the "Allowable Pipeline Product Changes Table", reduce H_2S, reduce maximum operating pressure, change the flow direction, minor modifications to an installation or to split a segment to a pipeline authorized under the permit, do not require an amendment to the permit providing the pipeline permit includes the notification permission and:

- prior notice of the change is provided, in the form and manner the BC Energy Regulator requires;
- the change is not made before the 7th day after the notice identified in (a) is submitted or the day the permit holder receives notification from the BC Energy Regulator, whichever occurs first;
- the change does not affect direct connections to pipelines and facilities;
- there are no changes to approved pressure protection, H_2S protection or isolation;
- there is no substantive impact to any aspect of the project that was included in the consultation;
- the design and operation of the pipeline continues to meet all regulatory requirements and the requirement of CSA Z662.

The notification can be submitted two ways: either through a historical pipeline submission or as a Notice of Pipeline Change through eSubmission as outlined below. If a Permit holder is submitting an amendment for activities that do not fall under the notification criteria, they may also include the notification changes as part of the amendment application.

Notification for splitting a pipeline segment and minor modifications to an installation that require the upload of new spatial data are accepted as a historical pipeline submission through the Application Management System (AMS). As the spatial data requirements are different for a notification than for an amendment, permit holders must ensure the correct guidance in the AMS User Manual is followed.

The following pipeline changes that do not require the upload of new spatial data can be submitted either as a Notice of Pipeline Change through eSubmission or as part of the historical submission if spatial data is needed.

- changes to outside diameter
- adjusting the wall thickness
- changes to the pipe grade
- certain allowable pipeline product changes as identified in the Allowable Pipeline Product Change Table
- reducing H_2S
- reducing the maximum operating pressure
- changing the flow direction

NOTE: Prior to submitting a notice of pipeline change in e-submission, permit holders must also ensure that all amendments and/or historical submissions for the pipeline project have been processed. If a notice of pipeline change is submitted while an amendment application or historical submission is "in progress" or "in review," and not processed, the information provided in the notification may be overwritten with the information from the amendment application or submission after it is approved and processed.

Allowable Pipeline Product Change Table

The following pipeline products can be changed using a notification process via the Notice of Pipeline Change in e-Submission provided the new product is within the same grouping shown in the table below. Product changes not shown within the same grouping must be submitted as an Amendment Application in AMS.

Permitted Pipeline Product		**Notification can be submitted for a product change to the types within these groups.**
Sour Oil Well Effluent Crude Oil Low Vapour Pressure Multi-phase Oil Emulsion Oil Well Effluent Sour Crude	⇄	Sour Oil Well Effluent Crude Oil Low Vapour Pressure Multi-phase Oil Emulsion Oil Well Effluent Sour Crude
Coalbed Gas Methane Fuel Gas Natural Gas – Sour Natural Gas – Sweet	→	Air Coal Bed Gas Methane Fuel Gas Natural Gas – Sweet
Salt Water Sour Water Produced Water	→	Fresh Water Salt Water Sour Water Produced Water

Temporary Product Changes

*A permit holder may temporarily convert a natural gas pipeline to transport fresh or produced water for hydraulic fracturing for up to 6 months only. The permit holder must ensure that the pipeline is suitable for the intended use and comply with all the requirements of CSA Z662.

Natural Gas* - Sweet Natural Gas* - Sour	⇄	Fresh Water Produced Water

11.5.11 Notice of Intent Matrix

Table 11A below reflects required submissions for Notices of Intent. Unusual circumstances may result in changes to these requirements.

Table 11A Notice of Intent Matrix

		Pre-Construction	**During Construction**		**Post Construction**
	Notice of Intent	Notice of Construction Start	Notice of Pressure Test	Leave to Open	As-Built
Decrease MOP (upstream)	Y	N	N	Y	N
Decrease MOP (downstream)	Y	N	N	Y	N
Modify Data	Y	M	M	M	M
Repair/Replace (in-kind)	Y	M	M	M	N
Integrity Activities	Y	N	N	N	N
Install Farm Tap	Y	Y	Y	Y	Y

Deactivate / Abandon Pipeline	Y	N	N	N	Y*
Reactivate Pipeline	Y	N	M	Y	Y*
Change Class Location	Y	N	N	N	N

Legend: Y=Required submission Y*=if not previously submitted for deactivated and reactivating lines
N=Not required M=May be required if any work was done to allow for task.

11.6 Pipeline Amendments

Pipeline amendments are requests to change the operating parameters of the original permit; therefore, the Commission is required to make a determination on the amendment application. All permit amendments are submitted through the AMS, refer to the Oil and Gas Activity Application Manual.

Changes that require a pipeline amendment are:

- Increase in maximum operating pressure.
- Modify pipeline.
- Repair/ replace (not in-kind).
- Add installations.
- Change of service.

Changes which would normally be submitted as Notices of Intent, Notifications , or Administrative Changes may be included in the scope of the amendment to avoid multiple submissions. However, changes in the amendment scope may not be included in Notices of Intent or Notification processes.

Changes to pipeline activity that does not require an amendment, can be submitted as a notification. More information on which activities can be submitted through the notification process, including how to submit a notification, can be found in Section 11.5.10 - Notification for Pipeline Change, of this manual.

Amendment Matrix

Table 11B below reflects the normally required post application submissions for pipeline amendments. Unusual circumstances may result in changes to these requirements.

Table 11B Amendment Matrix

		Pre-Construction	During Construction				Post Construction
	Amendment	**Notice of Construction Start**	**Facility Amendment**	**Facility Notice of Intent**	**Notice of Pressure Test**	**Leave to Open**	**As-Built**
Increase MOP	Y	N	N	N	Y	Y	M
Modify Pipeline	Y	Y	N	N	Y	Y	Y
Repair/Replace (not in-kind)	Y	Y	N	N	Y	Y	Y
Change of Service	Y	N	M	M	M	Y	M
Add Installations	Y	Y	N	N	Y	Y	Y

Legend: Y=Required submission N=Not required M=May be required if any work was done to allow for task.

Historical Pipeline Submission

The pipeline historical submission is intended to get missing data into KERMIT, including dates for NCS, NPT, LTO and as built for historically approved pipelines. The historical pipeline submission can also be used for notification of pipeline changes that require the upload of new spatial data. Specific details for a historical pipeline submission can be found in the Oil and Gas Activity Application Manual and the AMS User Manual.

Chapter 12 Facility Activity

12. Facility Activity

The facility activity section of this manual provides operating guidelines for regulatory requirements throughout the operations life cycle of the permitted activity. Construction activities are discussed in Section 4 of this manual. Associated oil and gas activities, if required in addition to the oil and gas activity permit, are touched on in Section 3.1 of this manual.

Liquefied Natural Gas (LNG)

Applicants planning to construct and operate a Liquefied Natural Gas facility (LNG facility) in British Columbia should review the Liquefied Natural Gas Facility Application and Operations Manual. Permit holders must be familiar with the requirements and procedures for applying and obtaining a permit to construct and operate an LNG facility.

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.

12.1 Facilities Permitted Activities

All permit holders are ultimately responsible for ensuring they understand and meet all legal and regulatory requirements of the permit, including all conditions attached to the permit. If an exemption is requested from regulatory requirements, an exemption must be prepared at the time of application. Permit holders must contact the Commission prior to commencing construction or operations if the adherence to the permitted activity cannot be met. The Commission may be able to provide further guidance and clarification.

12.1.1 Facilities Defined

Facilities are an oil and gas activity, and are defined in OGAA as:

- A system of vessels, piping, valves, tanks and other equipment used to gather, process, measure, store or dispose of petroleum, natural gas, water or a substance referred to in paragraph (d) or (e) of the definition of pipeline.

12.1.2 Regulatory Requirements

Facilities must meet the design and operational requirements outlined in the Oil and Gas Activities Act (OGAA), Oil and Gas Waste Regulation (OGWR), Drilling and Production Regulation (DPR), the Environmental Protection and Management Regulation (EPMR) and the Liquefied Natural Gas Facility Regulation (LNGFR).

12.1.3 Guidance Requirements

Facility activities should meet CSA Z276, CSA Z662 and ASME B31.3 standards, and the guidance recommendations in the following Commission documents:

- Measurement Requirements for Upstream Oil and Gas Operations manual.
- Flaring and Venting Reduction Guideline.
- BC Noise Control Best Practices Guideline.

Contact the following for compliance requirements:

- Technical Safety BC (BCSA) for the registration of all unfired pressure vessels and the Memorandum of Understanding between the Commission and Technical Safety BC.

Additional legislation, regulations and/or standards permit holders should adhere to include:

- Fugitive emissions management program must be in place prior to commencement of operations at a facility. The Commission may request this program at any time in the application, construction or operations phase of a facility. Refer to the CAPP Best Management Practice for Fugitive Emissions Management document for further guidance.

- Leak detection system with adequate controls must be in place according to Section 39 of the Drilling and Production Regulation. The Commission may require additional levels of detection and control based on the location and specifics of a facility installation. Examples of common leak detection and control include high/low pressure alarms/shutdown, H_2S/LEL/fire detection, ESDV, etc.
- Overpressure protection must be designed and operated according to CSA Z662 and/or ASME B31.3. The Commission may require additional levels of detection and control based on the location and specifics of a facility installation.
- Secondary containment, storage tank design and water storage at a facility must meet standards as described in detail in the Facilities Planning and Design section of the Oil and Gas Activity Application Manual.

12.2 Facility Construction Requirements

Permit holders must complete a Notice of Construction Start and specific construction requirements as detailed in Chapter 4 of this manual.

Prior to beginning construction submit a Notice of Construction Start in KERMIT. Notices must be submitted prior to commencement of land clearing and/or the set-up of equipment on location and at least two days before construction is to begin.

12.2.1 Notice of Pressure Test for Facilities

Section 76 (b) of the Drilling and Production Regulation states:

- A facility permit holder must notify the Commission at least two days before conducting a pressure test on process piping at a facility.

Notice of pressure test may be either a shop or field test as follows:

- Shop tests are pressure tests conducted in the shop, usually used during repairs or modifications of short segments. Generally, shop tests are used for pre-testing pipe.
- Field tests are pressure tests conducted on site during construction or maintenance activities.

Notices of pressure test must be submitted in KERMIT.

12.2.2 As-built Submission Requirements for Facilities

As-built specifications, data and drawings provide the Commission with information about the technical aspects of the constructed facility. This information must be submitted to the Commission as an As-built submission within 90 calendar days of submitting Leave to Open. Submit through KERMIT.

As-Built Submissions

All As-Built submissions for facilities under the Drilling and Production Regulation must include the following attachments:

- Up to date and accurate piping and instrumentation diagrams (P&IDs).
- Up to date and accurate plot plans.
- Up to date and accurate metering schematics.

All record drawing submissions for facilities under the Liquefied Natural Gas Facility Regulation must include the following attachments:

- Up to date and accurate process flow diagrams (PFDs).
- Up to date and accurate metering schematics.
- Up to date and accurate plot plans.

Information on the As-Built P&IDs should include, but not be limited to:

- Design standards and code of construction.
- Specification breaks, code breaks and rating breaks.
- Mechanical line lists and/or P&ID symbology lead sheet.
- Meter design, type and information.
- Pressure vessel CRN, design, size and rating.

- Safety equipment such as LEL, fire and H_2S detection.
- Set points of all control equipment and fail position of control valves and equipment.
- Flow direction and labeling of fluid types.
- Slope direction of piping.
- Indication of the boundary between the facility permit and the pipeline permit (if applicable).

Information on the As-Built Plot Plan should clearly identify the surface area required for the facility and proposed equipment and as a minimum include:

- Lease area.
- Access roads.
- Any fencing, gating, or other access control measures.
- Layout of all equipment and facility piping.
- Wellheads.
- Blackened areas.
- Risers and any pipelines leaving or entering the facility.
- Adjacent ROWs within 100 metres of the site boundary (i.e.: utilities, pipelines, road allowances, easements, etc.).
- A scale (in metres) and legend.
- Any relevant off-lease information.

Information on the As-built metering schematics should include, but not be limited to:

- Design standards and code of construction.
- Meter design, type and information.

Additional Information

- For historical submissions, the P&ID's need to include all metering information.
- Typical drawings (one P&ID for multiple well sites, non-engineering drawings, etc.) are not acceptable for all As-Built submissions.
- The equipment list in KERMIT should be reflected on the P&ID attached.
- In cases where an As-Built has only been done to a section or sections of a large facility site, only applicable drawings need to be stamped and sealed by a Professional Engineer. When an As-Built is submitted for the amended portion of an already As-Built facility, only the amended portion is required to be submitted.

  Note: As-Built documentation for the entire facility must be kept on hand as the Commission may request this information in full at any time.
- In situations where many pages of drawings exist and an index sheet identifying each drawing is included, the Professional Engineer need only sign and seal the index sheet indicating signing and sealing for all subsequent drawings. If an index sheet is not provided, each drawing must be signed and sealed in accordance with Section 20(9) of the [Engineers and Geoscientists Act](#).
- Referenced manufacturer P&IDs must be included in as-built submissions, and a British Columbia Professional Engineer must verify and seal documentation confirming relevant legislation has been met. Refer to the EGBC's Use of Seal document for additional information and clarification.
- If an As-Built includes facility piping, the piping specifications must be shown on the P&ID or can be summarized on the mechanical line list.

As-Built Submissions: Professional Sign Off and Disclaimer

As-Built drawings submitted to the Commission in accordance with the regulatory requirements must be sealed by a professional engineer licensed or registered under the Engineers and Geoscientists Act.

The Commission notes that in applying a professional seal, an engineer is attesting to the fitness for purpose and compliance of the sealed drawings. As such, Engineers and Geoscientists BC has prepared the following advice to members:

- In order to avoid exposing professional engineers to discipline action and potential lack of professional liability coverage, as-constructed drawings should only be signed and sealed by a professional engineer when a certification is included on the drawing.

- Certification includes the disclaimer: The signature and seal of the undersigned on this drawing certifies the design information contained in these drawings accurately reflects the original design and the material design changes made during construction were brought to the undersigned's attention. These drawings are intended to incorporate addenda, change orders and other material design changes, but not necessarily all site instructions.
- The undersigned does not warrant or guarantee, nor accept any responsibility for the accuracy or completeness of the as-constructed information supplied by others contained in these drawings, but does certify the as-constructed information, if accurate and complete, provides an as-constructed system which substantially complies in all material respects with the original design intent.

The Commission accepts drawings sealed with the aforementioned caveat. To assist professional engineers, a copy of the letter in which Engineers and Geoscientists BC relayed this information to the Commission was attached to the Information Bulletin INDB 2010-14.

Once an As-Built has been submitted, it will either be automatically accepted and an email will be generated from the KERMIT database, or the As-Built will be reviewed by the Facilities Engineering group. The applicant will be contacted if more information is required, and/or once the As-Built has been accepted.

12.3 Facility Pre-Operations Requirements

Permit holders must comply with emergency management, start-up inspections and Notice of Pre-operation testing, Leave to Open (for LNG facilities) and Leave to Operate requirements where applicable and as detailed in this section.

12.3.1 Emergency Management Response Plans

Permit holders must prepare and maintain an emergency management program and a response contingency plan as prescribed in the Emergency Management Regulation (EMR). In addition to the requirements and processes described in the EMR and the Commission's Emergency Management Manual, response plans for facilities should include incident reporting requirements in accordance with the Spill Reporting Regulation and the Commission's Incident Reporting Procedures and Guidelines.

According to the Environmental Management Act, permit holders require a Waste Discharge Permit prior to start-up of facility operation.

12.3.2 Start-up Inspection

OGAA permits and permit amendments may include specific conditions for start-up notifications and inspections taking place prior to the facility being brought into service. The facility types typically requiring start-up inspections are gas processing plants, compressor stations, other large, more complex facilities, and those where there are increased risks to the public and the environment.

12.3.3 Leave to Open

Section 76 (c) and (d) of the Drilling and Production Regulation states:

- A facility permit holder must notify the Commission at least one (1) day before beginning production operations or putting new or modified equipment in service at a facility.

The Leave to Open is the same for both upstream and downstream activity. The Leave to Open may be submitted once the Notice of Pressure Test is accepted and one day or 24 hours before commissioning.

Leave to Open is submitted using KERMIT. Access to KERMIT is found on the Online Services page of the Commission's website. Permit holders should include the following information:

- Proposed date of commissioning, which must be at least 24 hours after the Leave to Open application is submitted in KERMIT.
- Pressure test charts and other construction/testing information is not mandatory for submission, but must be kept by the permit holder for future audit purposes.

12.4 Facility Operational Requirements

Permit holders must comply with the following where applicable and as detailed in this section:

- Notice of Intent
- Emergency and safety reporting
- Notice of Flaring
- Ongoing reporting

12.4.1 Notice of Intent

A Notice of Intent (NOI) is an electronic notice submitted through KERMIT to capture and report on operational changes, modifications and/or repairs to existing facilities requiring no new acquisition of land. The information collected is used by the Commission to track and manage changes. A facility Notice of Intent may include:

- Modifying equipment or facility when:
  - Decreasing H_2S concentration.
  - Decreasing inlet capacity.
  - Leak detection equipment changes.
  - Changing a facilities production reporting designation (Reporting / Non-reporting).
- Canceling facility or activity.
- Reactivating a Facility.
- Suspending a Facility.
- Removing a Facility (All equipment was removed).

Appendix F and G provide a comprehensive list of facility changes requiring a facility permit amendment and changes where no amendment or NOI is needed. Notice of Construction Start, Notice of Pressure Test, Leave to Open and As-Built are not required for Notices of Intent.

A Notice of Intent is submitted using KERMIT. Access to KERMIT is found on the Online Services page of the Commission's website.

Replacement-in-kind

Replacement-in-kind allows a company to repair or replace equipment without the requirement of neither a Notice of Intent nor an application amendment. A replacement-in-kind is considered a maintenance procedure. The following conditions must be met for the equipment to be considered as a replacement-in-kind:

- Equipment replaced and/or repaired has been approved for installation under a previous and valid permit.
- Equipment replaced and/or repaired is essentially the same as the current.
- No change in size, design, capacity or function.
- No significant increase in noise or traffic than would otherwise be required for a maintenance related activity.

All facility piping changes, addition, modifications or deletions meeting all of the above criteria may be completed without a KERMIT Notice of Intent submission or an application amendment.

12.4.2 Facility Design and Operational Controls

In addition to the emergency planning and response programs and incident prevention controls discussed in Sections 12.3.1 and 3.3 of this manual, facilities must adhere to the following programs, controls and guides:

1. Fugitive emissions program
2. Leak detection and control
3. Sand management plan
4. Water management plan
5. Overpressure protection

6. Secondary containment
7. Truck out boxes
8. Storage tank design
9. Measurement at cross border facilities
10. Motor fuel tax and carbon tax requirements
11. Additional considerations for on-site equipment

Fugitive Emissions Program

A Fugitive Emissions Management Program must be in place prior to commencing operations at a facility. The Commission may request this program at any time in the application, construction or operations phase of a facility.

For more information, refer to Section 4.3.3 of the Oil and Gas Activity Application Manual.

Leak Detection and Control

A leak detection system with adequate controls per the Drilling and Production Regulation must be in place. The Commission may require additional levels of detection and control based on the location and specifics of a facility installation.

For more information, refer to Section 4.3.3 of the Oil and Gas Activity Application Manual.

Sand Management Plan

The sand management plan is a comprehensive plan outlining the preventative steps to reduce, monitor, and capture sand returns, and incorporate leak detection and piping integrity. All records relating to sand monitoring and testing programs must be maintained and made available to the Commission upon request.

Sand management plan requirements are detailed in the Oil and Gas Activity Application Manual.

Water Management Plan

The water management plan is intended to be a comprehensive plan outlining the design, operations and inventory management of produced and fresh water storage facilities. All water hub facilities and facilities with excavated ponds and pits or permanent C-rings must include a water management plan (WMP) with the application. All records relating to water monitoring and testing programs must be maintained and made available to the Commission upon request.

For more information, refer to Section 4.3.3 of the Oil and Gas Activity Application Manual.

Overpressure Protection

Overpressure protection must be designed and operated according to CSA Z662 and/or ASME B31.3. The Commission may require additional levels of detection and control based on the location and specifics of a facility installation.

For more information, refer to Section 4.3.3 of the Oil and Gas Activity Application Manual.

Secondary Containment

All produced oil, water and condensate storage (production) tanks as outlined in Section 50 of the DPR must meet the specified secondary containment requirements.

For more information, refer to Section 4.3.3 of the Oil and Gas Activity Application Manual.

Truck Out Boxes

Truck-out boxes are considered spill or leak prevention devices, not secondary containment. As a best practice, the Commission recommends the boxes are installed inside the tank's secondary containment boundary. Any deviation from this design must achieve the same results, and is considered on a case by case basis. The design should be configured to enable the truck operator to remain outside the secondary containment area while loading and unloading the fluid.

For more information, refer to Section 4.3.3 of the Oil and Gas Activity Application Manual.

Truck out boxes should be reflected on the drawings relative to the tank's secondary containment boundary as follows:

- By showing the location of the truck out boxes on the Plot Plan, PFD or P&ID, and/or
- By inserting a note on the drawings stating the location of the truck out boxes

Storage Tank Design

The general standards for atmospheric and low-pressure petroleum storage tanks in B.C. are included in the following American Petroleum Institute (API) documents:

API-650	Welded Steel Tanks for Oil Storage: governs the construction of tanks storing products with internal pressures of up to 2.5 psig.
API-651	Cathodic Protection for Above-Ground Petroleum Storage Tanks.
API-652	Lining of Above-Ground Petroleum Storage Tanks.
API-653	Tank Inspection, Repair, Alteration, and Reconstruction.
API-620	Design and Construction of Large Welded Low-Pressure Storage Tanks: construction of tanks with internal pressures of up to 15 psig.
API-2000	Venting Atmospheric and Low-Pressure Storage Tanks.
API-2350	Overfill Protection for Petroleum Storage Tanks.
API-2015	Cleaning Petroleum Storage Tanks.
API-2550	Measurements and Calibration of Petroleum Storage Tanks.

For general requirements on underground tank inspections and abandonment, refer to CSA Z662, API-1604 and NFPA 30. For more information, refer to Section 4.3.3 of the Oil and Gas Activity Application Manual.

Measurement at Cross Border Facilities

For guidance relating to measurement at cross border facilities, refer to the Measurement Requirements for Upstream Oil and Gas Operations Manual.

Motor Fuel Tax and Carbon Tax Requirements in British Columbia

In addition to the Commission's reporting requirements, permit holders, facility owners and operators may have tax reporting and payment obligations under British Columbia's Motor Fuel Tax Act, and/or Carbon Tax Act. Visit the Ministry's website at http://www2.gov.bc.ca/gov/content/taxes/sales-taxes or contact the Ministry of Finance toll free 1-877-388-4440 or by email at CTBTaxQuestions@gov.bc.ca.

Additional Considerations for On-site Equipment

Permit holders must factor in all on-site hazards and ensure all equipment is situated a safe distance from any roads, buildings, installations, works, or places of public concourse. The following list of equipment is generally not considered production equipment as per Section 48 of the Drilling and Production Regulation:

- Generators.
- Heat medium units.
- Instrument air units.
- Pigging equipment (pig senders/receivers).
- Chemical pumps.
- Risers.
- SCADA equipment.
- Chemical tanks.
- Propane tanks.
- Thermoelectric generators.
- MCC buildings.
- Office buildings.
- Storage buildings.
- Communication towers.

Other equipment deemed appropriate by the Commission may be included in this list.

12.4.3 Notice of Flaring and Venting

Review the Flaring and Venting Reduction Guideline for requirements regarding flaring and venting.

The Oil and Gas Waste Regulation includes parameters for air discharges from facilities and should be reviewed.

Planned Flaring Events

Planned flaring events are those occurring during operations where, in planning and carrying out the operations, the permit holder has a reasonable expectation flaring is needed. For these operations, provide notice to the Commission and the public of flaring 24 hours in advance of flaring events as per the requirements stated in the Flaring & Venting Reduction Guideline. Examples of these operations include, but are not limited to:

- Underbalanced drilling.
- Planned de-pressuring of process equipment and gas pipelines for maintenance.
- Commissioning and start-up of a new facility.

Unplanned Flaring Events

Unplanned flaring events are those occurring during operations where, in planning and carrying out the operations, the permit holder does not have a reasonable expectation flaring is needed. For these operations, provide notice of flaring within 24 hours of flaring events. Examples of these operations include:

- Drill stem testing.
- Managed pressure drilling.
- Drilling kicks.
- Unplanned de-pressuring of process equipment and gas pipelines due to process upsets or emergency.

Flared and Vented Gas Reporting

Report flared gas volumes to the Commission with 60 days of a flaring event. The process through which permit holders must report volumes of flared and vented gas is dependent on the oil and gas activity and operations associated with the flaring or venting event. The Flaring and Venting Reduction Guideline provides detailed reporting requirements.

In addition to providing notice to the Commission, permit holders must provide notice to all residents and administrators of incorporated centres within a specified radius of planned and unplanned flaring or venting events. The Flaring and Venting Reduction Guideline provides detailed reporting requirements.

Flared and vented gas volumes must be reported via Petrinex.

12.5 Historical Facility Entry

The historical facility entry enables permit holders to update any inaccuracies or absent data currently detailed in an ongoing facility permit. This includes equipment and compressor details. Specific details for historical facility entries can be found in the Oil and Gas Activity Application Manual.

12.6 Suspending a Facility for More Than Twelve Consecutive Months

Section 79(2) of the Drilling & Production Regulation states that all suspensions are carried out safely and that permit holders must immediately notify the Commission if a suspension continues for more than twelve (12) consecutive months.

If a compressor station, battery, tank terminal, gas dehydrator, disposal / injection station, or gas plant will be suspended for more than twelve (12) consecutive months, a suspend facility Notice of Intent is required.

The suspend facility Notice of Intent must be submitted to the Commission before or within twelve (12) months of suspending the facility.

A partial facility suspension, such as shutting down a compressor or dehydrator at a facility with multiple compressors or dehydrator packages, does not require a permit amendment or notification to the Commission.

Long-term facility piping deactivation must follow the requirements found in CSA Z662, common industry practices, and / or good engineering practices. A short-term suspension will include similar requirements to a long-term suspension with the exception of less stringent isolation requirements. For example, compressor unit or well facility isolation can include closed and locked valves vs. installing blinds or blanking plates.

Suspending a gas plant or facility requires both a project description and updated schematics uploaded as attachments in KERMIT along with the Notice of Intent.

Submit a project description for the safety and security of the facility. The Project description must show provisions have been made to:

- Empty all fluid from vessels, storage tanks, underground tanks, chemical tanks, etc.
- De-pressure the facility.
- Dispose of corrosive, combustible or explosive fluids.
- Minimize or prevent degradation of the plant or facility equipment, vessels and piping.
- Maintain cathodic protection, if applicable.
- Secure the plant or facility against unauthorized entry and vandalism, and monitor as appropriate.
- Periodically have the plant or facility and site inspected by qualified persons.
- Address any other concerns the Commission has identified.

The project description must include a list of wells from the schematic, rationale for shut-in, plan and duration of shut-in, and if / how the associated wells, pipelines and facilitates will also be suspended or deactivated in conjunction with the suspension.

Updated Schematics

Updated gathering system schematic showing where the wells (if any are effective) and facilities will be redirected to, as well as pipelines coming in or out of the facility.

12.7 Facility Removal and Remediation

Notice of Intent to Cancel a Facility: No Equipment Installed

All previously approved equipment listed on the permit and intended to be cancelled must never have been installed. A Cancel Facility or Activity Notice of Intent must be submitted when a project will no longer be constructed.

Notice of Intent to Remove a Facility: All Equipment Removed

When a permit holder has removed all the equipment and pilings (or cut 1 meter below grade and buried) from a facility site, they must submit a Notice of Intent (NOI). A project description and documentation of proof must be submitted to the Commission which should clearly identify all facility equipment and piping that was removed. The documentation of proof could include pictures of the location showing the equipment has been removed or a signed confirmation from the contractor that completed the removal.

A Notice of Intent (NOI) is an electronic notice submitted through KERMIT to capture and report on operational changes, modifications and/or repairs to existing facilities requiring no new acquisition of land.

12.8 Reactivating a Facility

Section 79(3) of the Drilling & Production Regulation and Section 23(2) of the Oil & Gas Processing Facility Regulation requires that permit holders notify the Commission at least 5 days before reactivating a suspended facility. This notice requires a Reactivate Facility NOI submission in KERMIT.

Reactivating a facility requires both a project description and up to date plot plan and PFD's uploaded as attachments in KERMIT along with the Notice of Intent. The Project description must include:

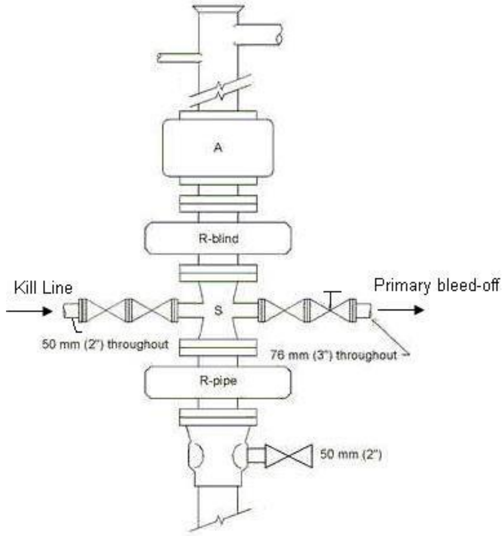
- Evaluations completed to confirm that the piping, equipment, pressure vessels, storage tanks, secondary containment, instrumentation, etc. are suitable for service.
- Confirmation that safety critical devices have been function tested.
- Confirmation that all meters have been calibrated and are in good working order.

Appendices

List of Appendices

Appendix A: Drilling Blowout Prevention Systems

Blow-Out Prevention Stack

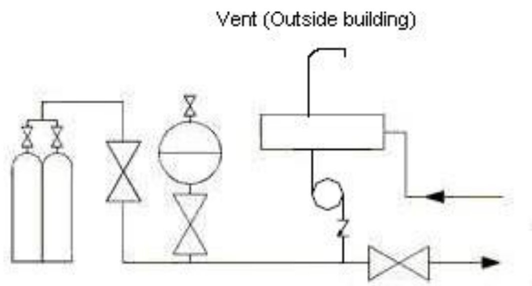


CLASS A

Surface Casing Depth - 1,800 metres (14,000-21,000 kPa).

Drilling Blowout Prevention System for Wells not exceeding a True Vertical Depth of 1,800 metres.

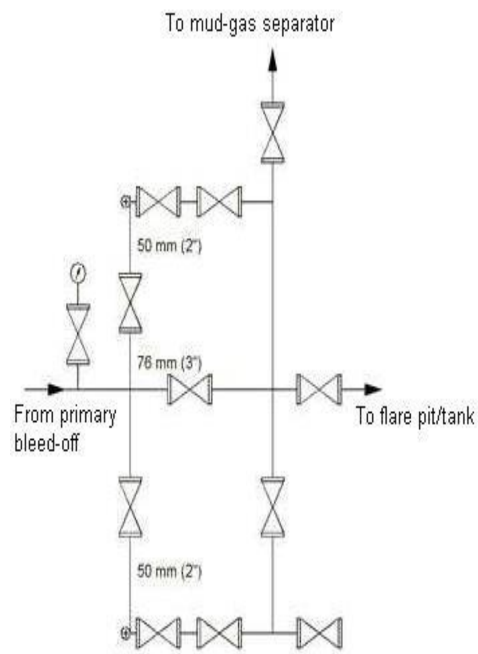
Minimum pressure rating: 14,000 kPa (2,000 psi).



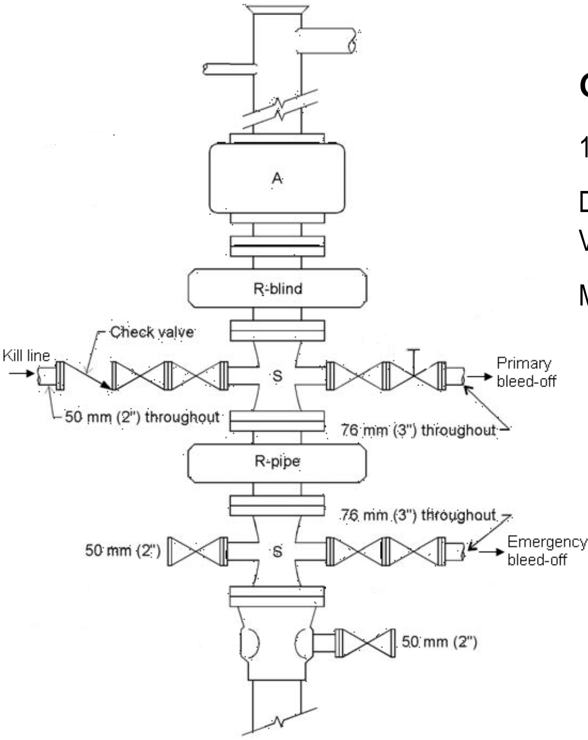
Accumulator System

Notes:

- Bleed-off line, centreline through choke manifold, and flare line must be a minimum nominal diameter of 76.2mm throughout.
- Lines through chokes must be a minimum nominal diameter of 50.8mm throughout.
- Kill line must be a minimum nominal diameter of 50.8mm throughout.
- Flanged pipe connections must be used from the drilling spool down to and including the connection to the choke manifold. The remainder of the choke manifold may contain threaded fittings.
- Minimum pressure rating for flares and degasser inlet lines is 14MPa.
- Hydraulic and manual valve positions in the bleed-off line may be interchangeable
- Ram type BOPs manufactured with integral outlets may be used in place of drilling spool, but must be inspected and re-certified if significant flow occurs through the body.



Choke Manifold

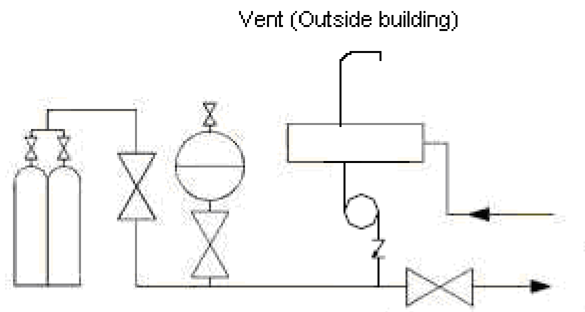


CLASS B

1,800-3,000 metres.

Drilling Blowout Prevention System for Wells not exceeding a True Vertical Depth of 3,000 metres.

Minimum pressure rating 21,000 kPa (3,000 psi).

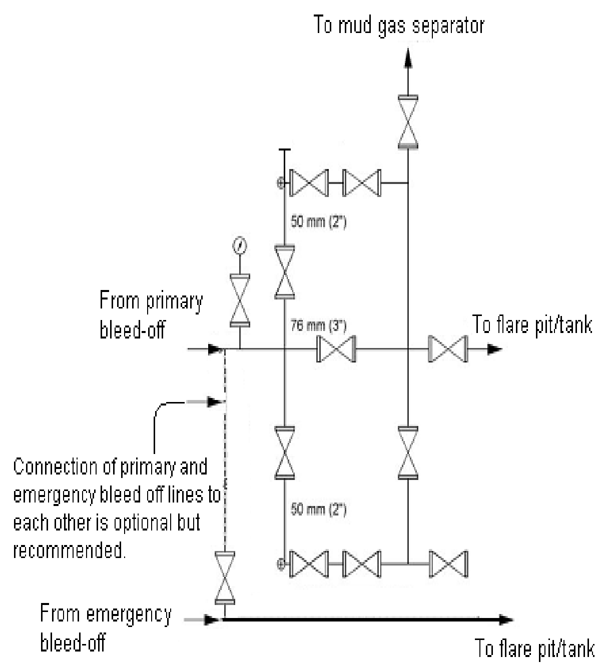


Accumulator System

Blow-out Prevention Stack

Notes:

- Bleed-off line, centreline through choke manifold, and flare line must be a minimum nominal diameter of 76.2mm throughout.
- Lines through chokes must be minimum nominal diameter of 50.8mm throughout.
- Kill line must be a minimum nominal diameter of 50.8mm throughout.
- Flanged pipe connections must be used from the drilling spool to the last valve on the choke manifold, inclusive
- Welded flanges required to connect primary and emergency bleed-off lines.
- Minimum pressure rating for flare and degasser lines is 14MPa.
- Hydraulic and manual valve positions in the bleed-off line may be interchangeable
- Ram type BOPs manufactured with integral outlets may be used in place of the drilling spools, but must be re-certified if significant flow has occurred through the body.



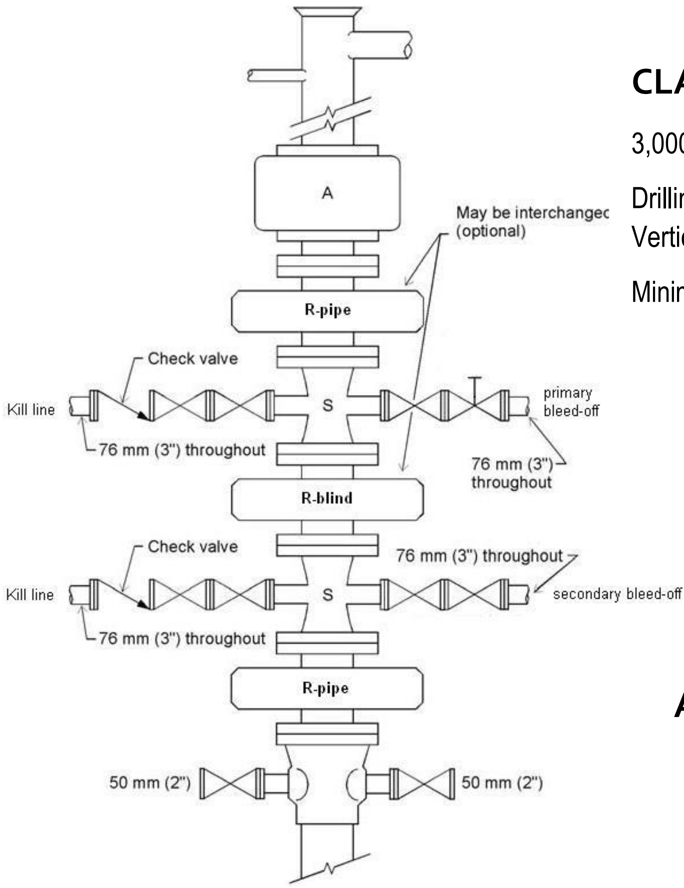
Manifold System

CLASS C

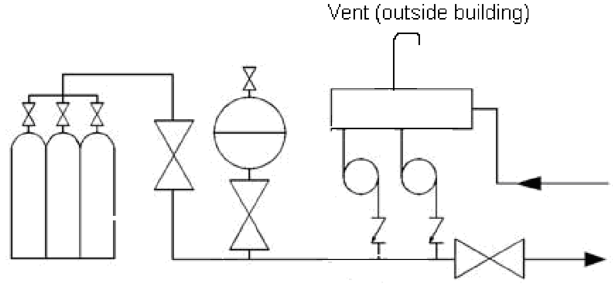
3,000-5,500 metres.

Drilling Blowout Prevention System for Wells not exceeding a True Vertical Depth of 5,500 metres.

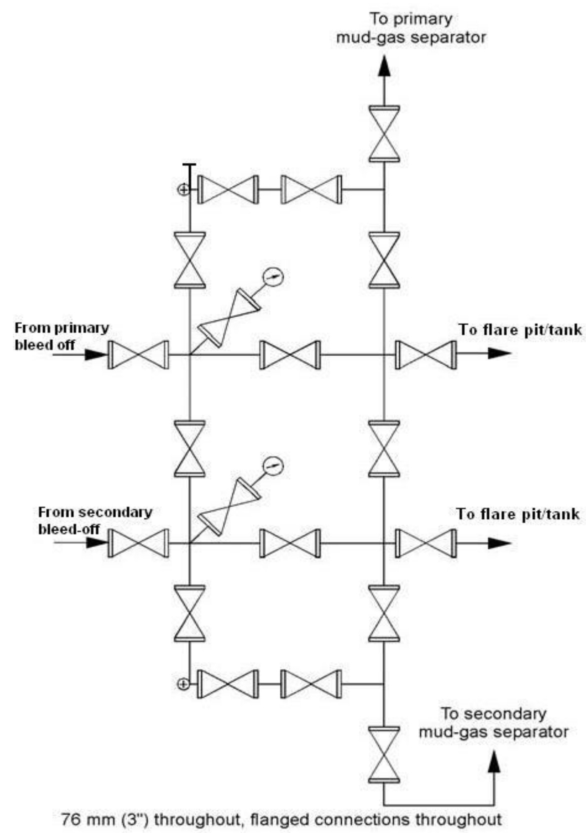
Minimum pressure rating 34,000 kPa (5,000 psi).



Blow-out Prevention Stack



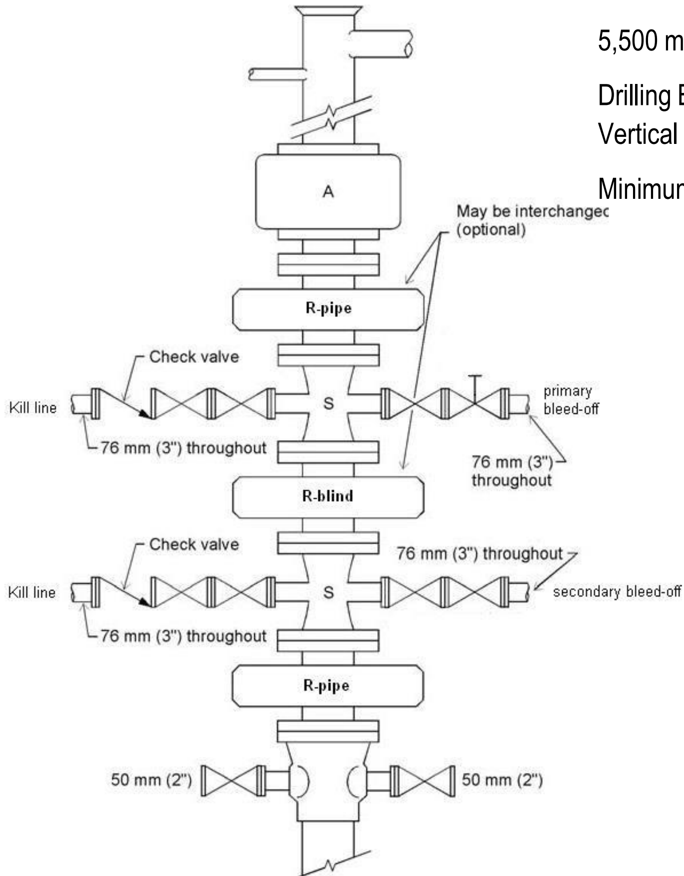
Accumulator System



Notes:

- Kill lines, bleed-off lines, choke manifold, and flare lines must be a minimum nominal diameter of 76.2mm throughout.
- Flanged pipe connections must be used from the drilling spool to the last valve on the choke manifold, inclusive.
- Minimum pressure rating for flare and degasser lines is 14MPa.
- Hydraulic and manual valve positions in the bleed-off line may be interchangeable.
- Ram type BOPs manufactured with integral outlets may be used in place of the drilling spools, but must be re-certified if significant flow has occurred through the body.

Blow-out Prevention Stack

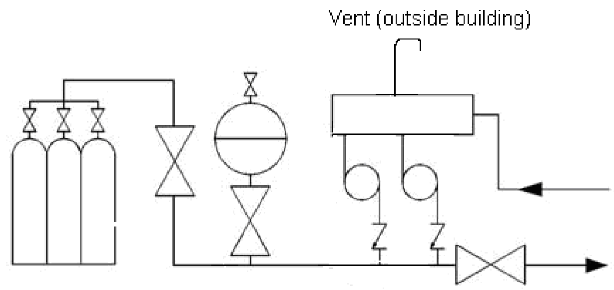


CLASS D

5,500 metres and deeper.

Drilling Blowout Prevention System for Wells exceeding a True Vertical Depth of 5,500 metres.

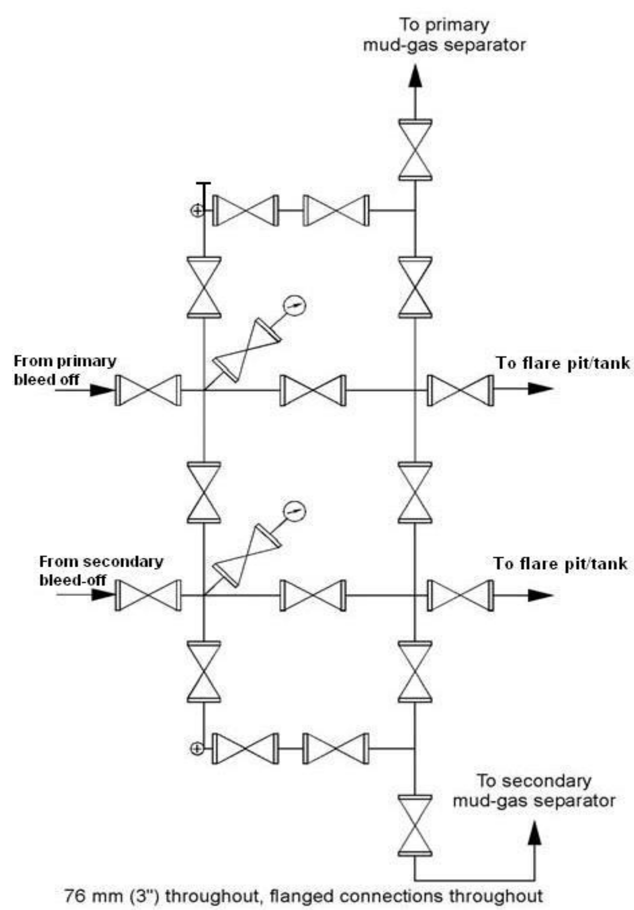
Minimum pressure rating 70,000 kPa (10,000 psi).



Accumulator System

Notes:

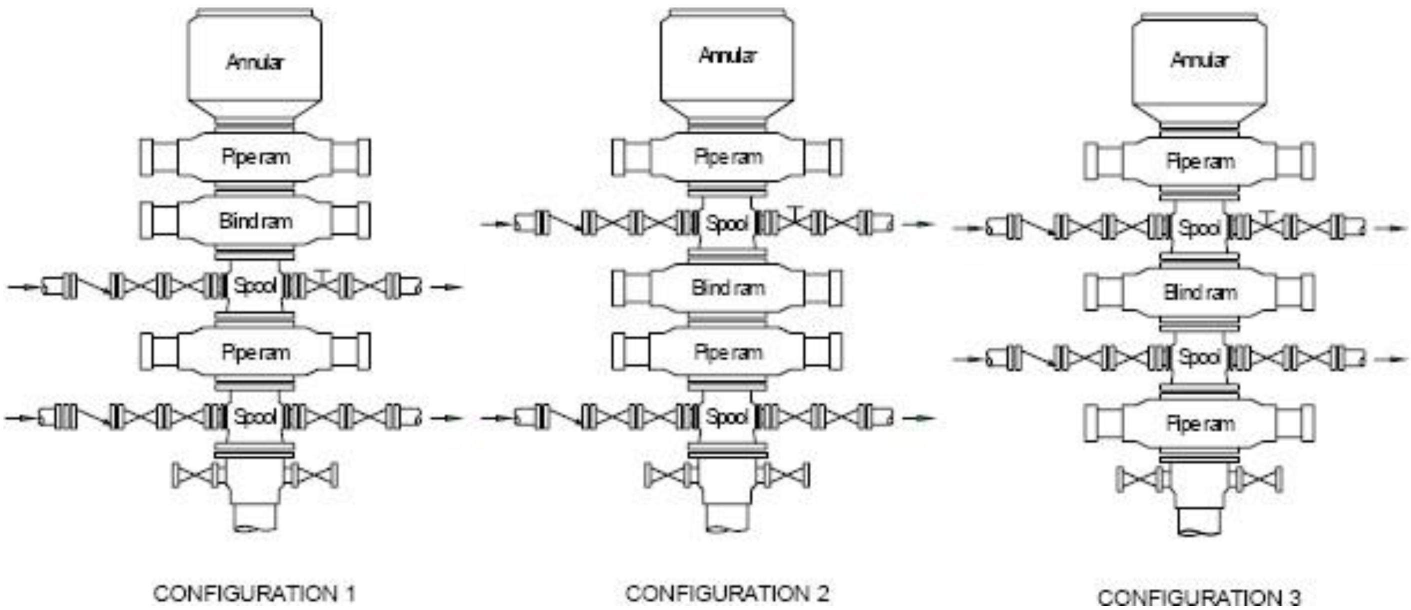
- Kill lines, bleed-off lines, choke manifold, and flare lines must be a minimum nominal diameter of 76.2mm throughout.
- Flanged pipe connections must be used from the drilling spool to the last valve on the choke manifold, inclusive.
- Minimum pressure rating for flare and degasser lines is 14MPa.
- Hydraulic and manual valve positions in the bleed-off line may be interchangeable
- Ram type BOPs manufactured with integral outlets may be used in place of the drilling spools, but must be re-certified if significant flow has occurred through the body.
- Other BOP stack configurations are acceptable, including the use of double gate rams. Stack must contain a minimum of 2 pipe rams and one blind ram.



Special Sour: All Depths

Drilling Prevention Systems for Special Sour Wells.

Minimum pressure rating 14,000 kPa (2,000 psi).

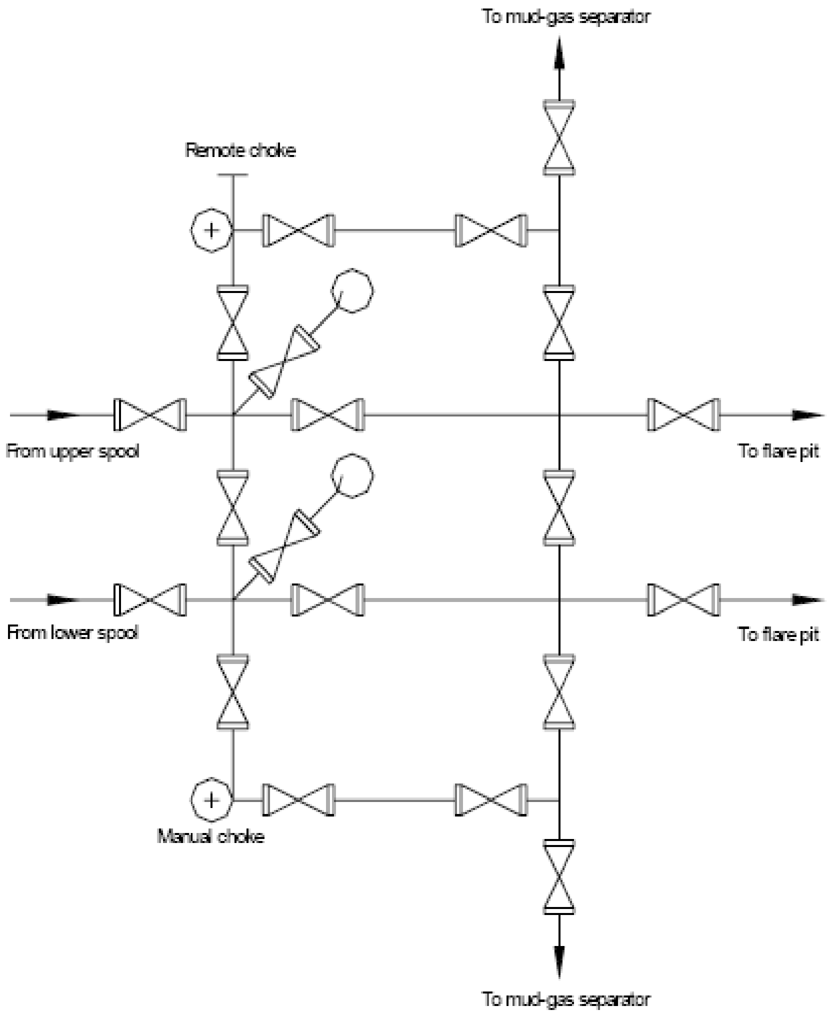


Note:

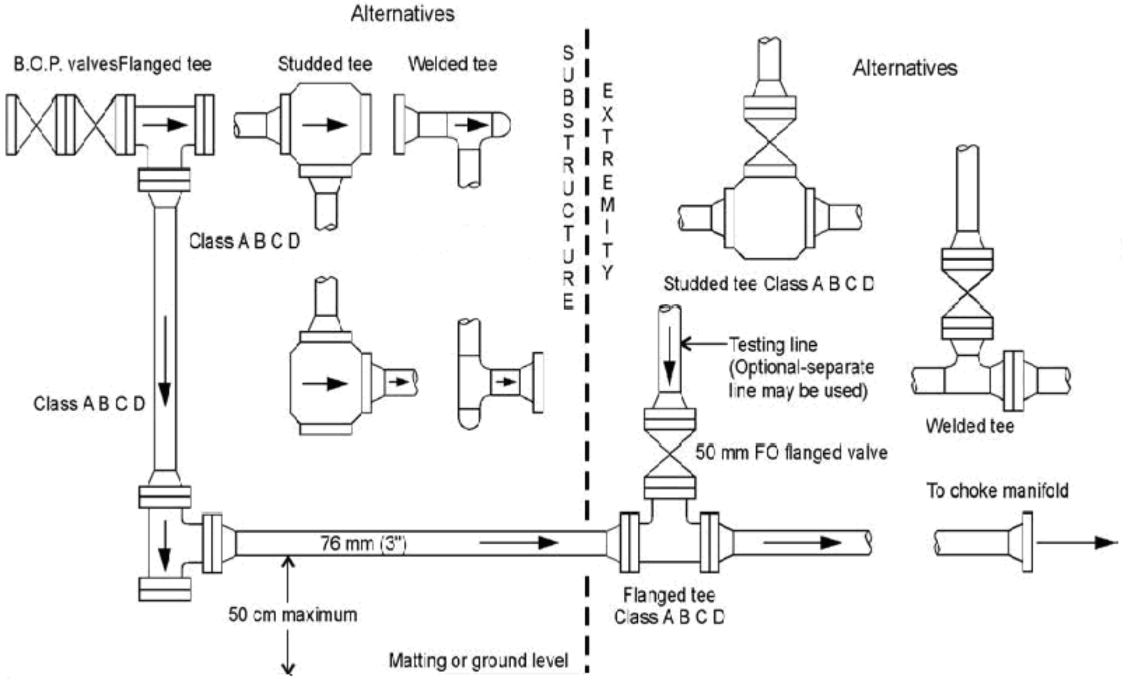
- Hydraulic and manual valve positions in bleed-off line are interchangeable
- If BOP Configuration 2 or BOP Configuration 3 is used, an appropriately sized ram blanking tool fitting into the top pipe ram must be on location and readily available.
- If BOP Configuration 3 is used, there must be sufficient surface or intermediate casing to contain the maximum anticipated reservoir pressure.
- Shear blind rams may be required in place of the blind rams.
- Rams type BOPs manufactured with integral outlet may be used in place of the drilling spools, but must be re-certified if significant flow has occurred through the bodies.

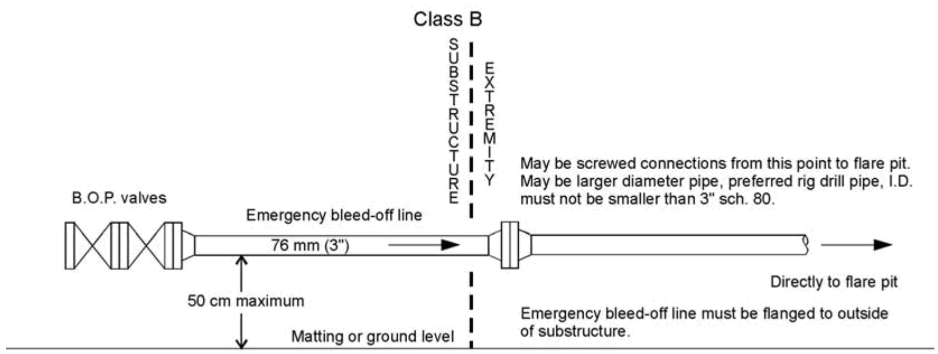
Special Sour Manifold

Minimum pressure rating 14,000 kPa (2,000 psi).

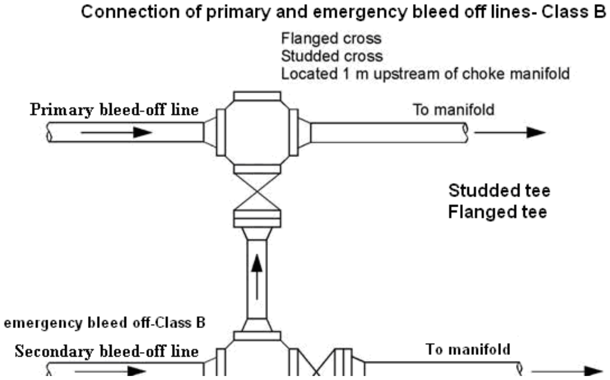


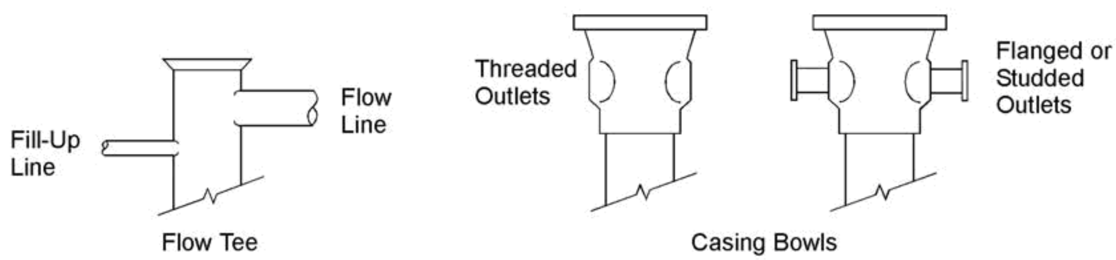
Bleed off lines – All Classes





Bleed Off Lines- Class C & D
Connection of primary and emergency bleed off lines- Class B

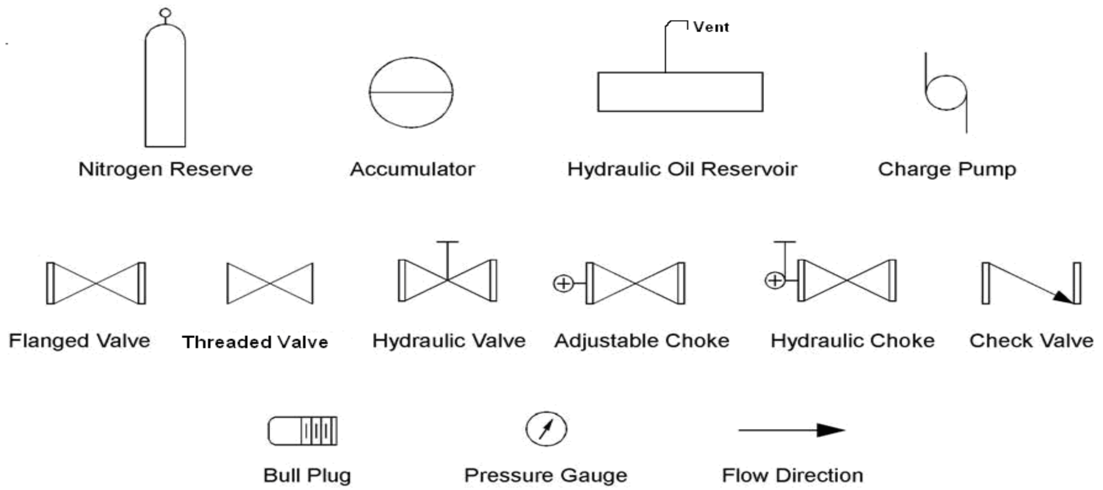




For all classes:

Class A, B, C and D diagrams indicate single ram preventer. The single blind ram preventer may be replaced with a double gate preventer.

Equipment Symbols

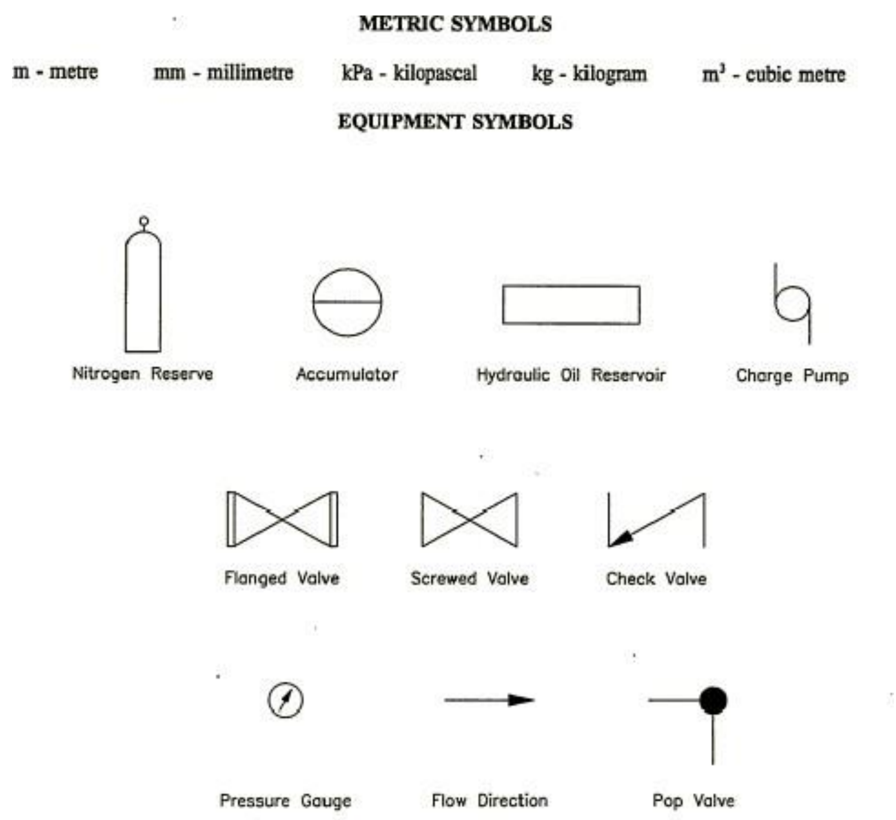


Note:

- R – Single ram type preventer with one set of blind or pipe ram.
- A – annular-type blowout preventer.
- S – drilling spool with flanged side outlet connections for bleed-off and kill lines.
- Flanged means weld necked flanges.
- A double gate blowout preventer may replace a single gate preventer but the lowest ram in any stack shall be a pipe ram.

Appendix B: Diagrams of Blowout Prevention Systems for Well Servicing

Figure B-1 Equipment Symbols



RATING OF PRODUCTION CASING FLANGE IS LESS THAN OR EQUAL TO 21000 kPa
H_2S CONTENT OF THE GAS IS LESS THAN 10 MOLES/KILOMOLE

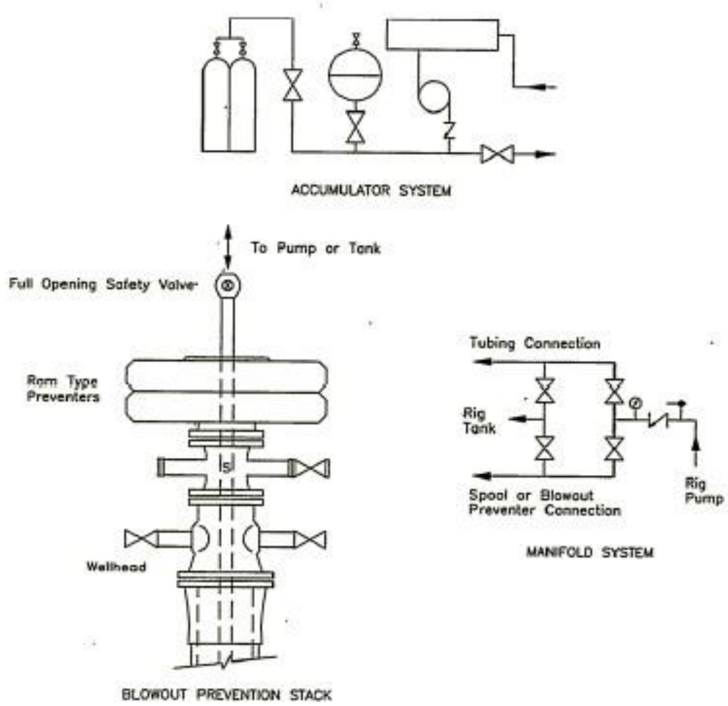


Figure B-2: BOP Class A Pressure Rating and Component Placement

- Pressure rating of preventers is equal to or greater than the production casing flange rating or the formation pressure, whichever is the lesser.
- 50 mm lines throughout.
- The positioning of the tubing and blind rams may be interchanged.
- Spool may have threaded side outlet (and valve) if wellhead has threaded fittings.
- A flanged BOP port (and valve) below the lowest set of rams may replace spool (valve may be threaded if wellhead has threaded fittings).

Rating of production casing flange is greater than 21 000 kPa or rating of production casing flange is less than or equal to 21 000 kPa and the H_2S content of the gas is equal to or greater than 10 MOLES per KILOMOLE.

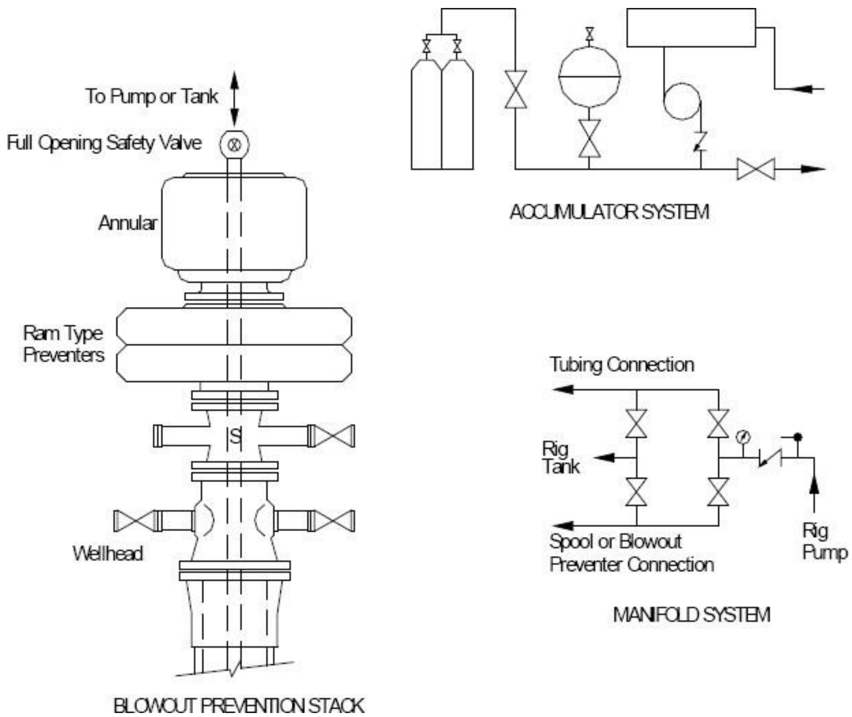


Figure B-3: BOP Class B Pressure Rating and Component Placement

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

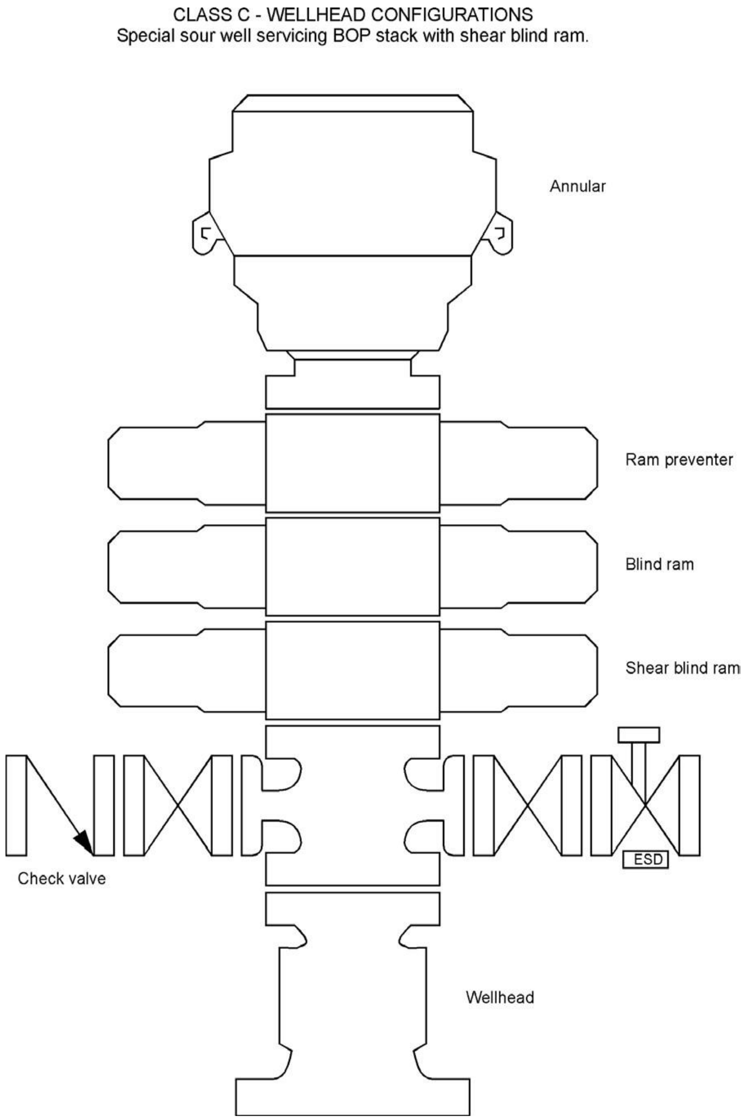


Figure B-4: BOP Class C Wellhead Configuration

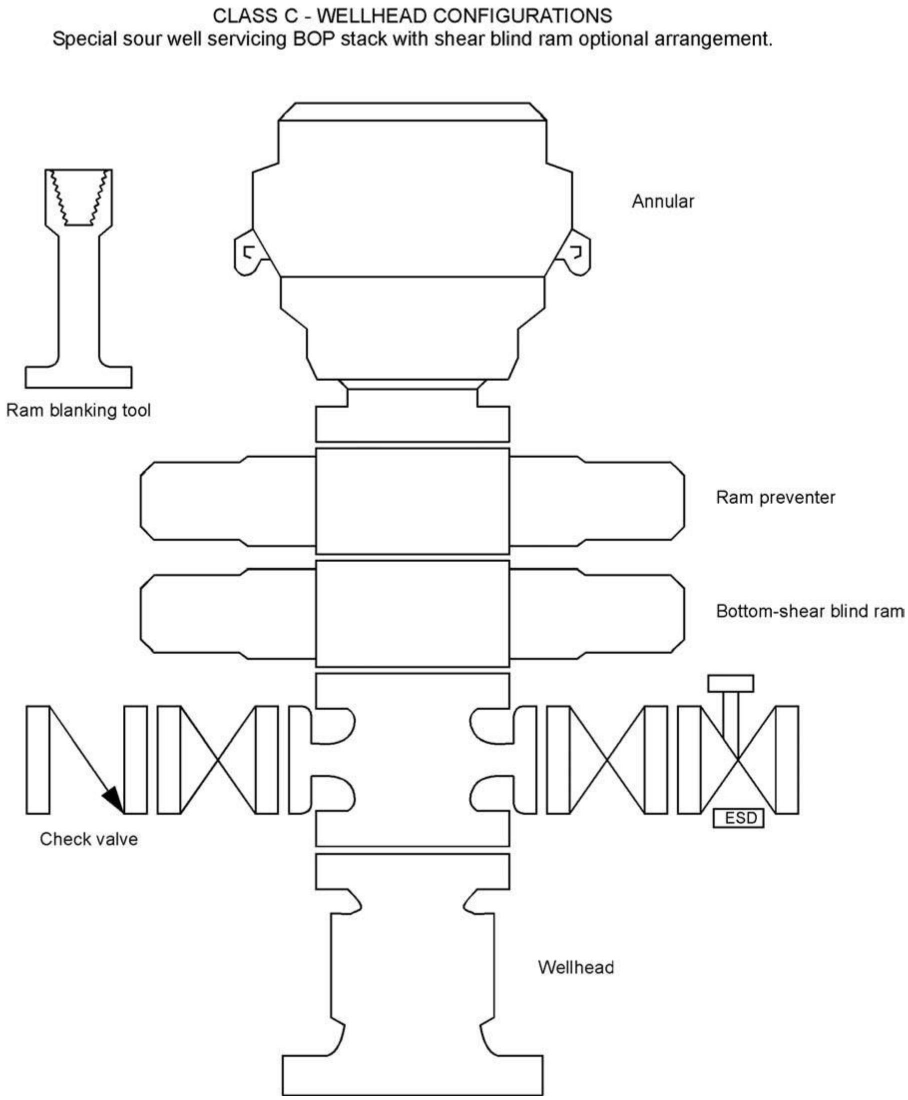


Figure B-5: BOP Class C Optional Wellhead Configuration

Appendix C: Alert for Operators Drilling in Quaternary Gravels

Originally published as an Information Letter to alert operators drilling in Quaternary Gravels, particularly in Midwinter-Helmet North Field areas, but also in the rest of British Columbia.

Background

On January 28, 2005 the Nabors 29 rig on the CNRL HZ Midwinter b-93-L/94-P-10 well encountered a low differential gas kick while drilling at approximately 140 m KB. The well blew out, ignited, and burned for approximately 12 hours causing one fatality and destroying the rig.

It seems the rig encountered a gas pocket in Quaternary gravels. These gravels are known to be pressured but water bearing in the northern portion of 94-P-15. The gravels have been encountered sporadically in the southern portion of 94-P-15 and the northern portion of 94-P-10. This is the first report of gas bearing Quaternary gravels within a 60 kilometer radius. No water was produced with this blowout.

Requirements

Quaternary gravels are present throughout northeast British Columbia. Equivalent gravels at Sousa field in T112-R1W6 and Rainbow T110-R3W6 in Alberta have produced gas. ISH Energy has produced gas from the Dunvegan zone at two wells in the Desan field at c-82-K & d-81-K/94-P-2. These wells are approximately 60 kilometres south of the blowout location. A new interpretation of this zone suggests it may be Quaternary gravels.

Deposition of Quaternary gravels is generally interpreted to be glacio-fluvial sediments in bedrock erosional lows. At Sousa field, there are occurrences of four stacked gravels found in one well bore. However, researchers have found significant gravel deposits on the flanks of bedrock highs. Minor gravel deposits on the tops of bedrock highs cannot be ruled out.

The gas in these gravels has been interpreted to be biogenic gas. The blowout zone pressure was reported to be of normal gradient. In light of the foregoing, operators are advised to:

4. Review new northeast British Columbia well locations thoroughly for the presence of bedrock lows and any indication of Quaternary gravels.
5. Design drilling programs with the expectation of encountering shallow Quaternary gravel gas in 94-P and 94-I. Serious consideration should be given to the use of diverters on subject area surface holes.
6. Take and monitor sample cuttings from the surface where gas bearing Quaternary gravels are anticipated and to have gas detection equipment operational.

7. Utilize “main” hole drilling practices on surface holes in this area (i.e. blowout prevention drills, trip sheets, avoid the pumping out of singles and possible resulting charge up of zones, etc).

Operators are also reminded of the standing requirement to run a gamma-ray log from total depth to surface (open-hole, cased-hole or Measurement While Drilling), data which may prove useful in the identification of shallow gas zones for the programming of future wells. The log data will assist industry and operators in mapping the gas-bearing gravel formations.

It is also noteworthy some recent well control problems have been experienced in shallower zones in other areas of British Columbia. The offending zones are thought to be Quaternary gravels or possibly the Dunvegan zone, but the source of the gas therein is uncertain at this time.

Appendix D: Classification of Low and Medium Risk Gas Wells

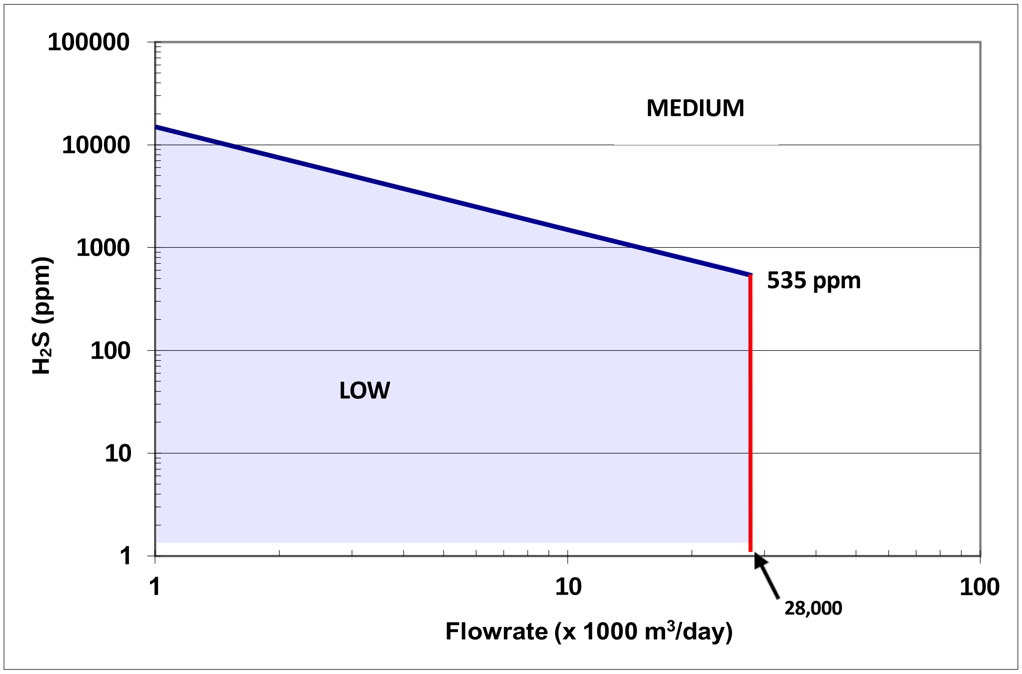
High Risk gas wells are gas wells classified as special sour or are acid gas disposal wells.

Medium Risk gas wells are gas wells where the maximum stabilized wellhead AOF exceeds the Maximum Allowable Flowrate of 28,000 m^3/day (as per Figure D-1), are not classified as High Risk gas wells, and any Low Risk well that became inactive on or before 2009-05-30.

Maximum Allowable Flowrate ($10^3 m^3$/day) = 15 x 10^3 / H_2S Concentration (ppm).

Low Risk gas wells are gas wells that are not classified as Medium or High Risk.

Figure D-1: Classification of Low and Medium Risk Gas Wells (Adopted from AER Directive 13).



Appendix E: Technical Guidance for Determining the "Base of Usable Groundwater"

The "base of usable groundwater" can be determined by the qualified professional, supported by review and analysis of local or site specific information, such as geology and stratigraphy, mapped aquifers, groundwater chemistry, or other data may be available through DataBC, iMapBC, or Commission well information. For this interpretation of the "base of usable groundwater", "usable" is defined by the Commission as groundwater with up to 4000 mg/L total dissolved solids.

Alternatively, the "base of usable groundwater" can be determined by the qualified professional, using the definition of "deep groundwater" in Section 51 of the Water Sustainability Regulation. Using this approach, the "base of usable groundwater" is defined as: between 300 m and 600 m below the ground surface, and below the "base of fish scales marker" or an identified older geological marker. The definition for "base of fish scales marker" can be found in the Water Sustainability Regulation.

For clarity, when using the geological marker based approach:

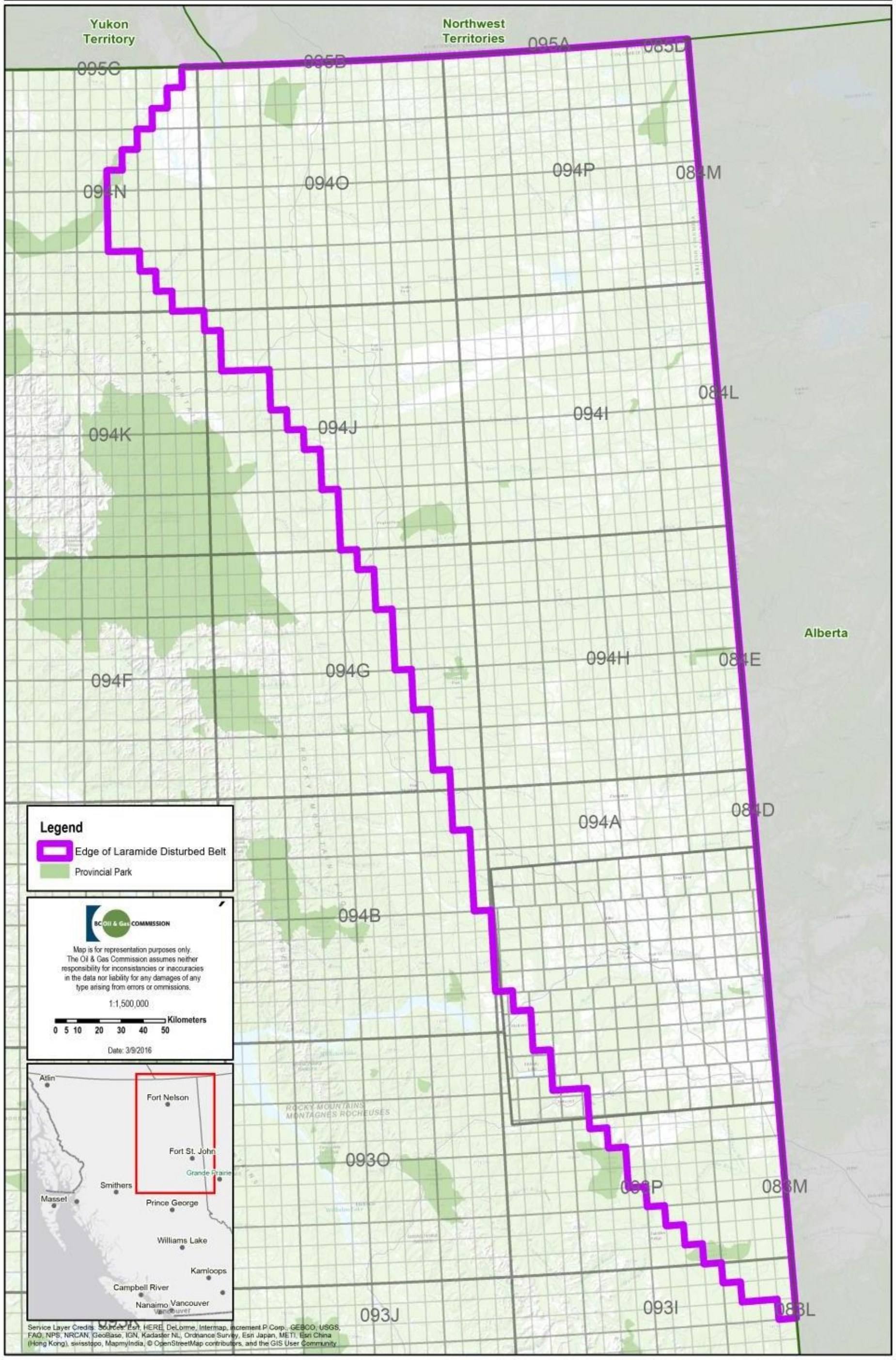
- The minimum depth of the "base of usable groundwater" is 300 m below the ground surface.
- The maximum depth of the "base of usable groundwater" is 600 m below the ground surface.
- Between 300 m and 600 m below the ground surface, the "base of usable groundwater" is identified to be the depth of the above-referenced geological markers. The geological marker may be interpreted using well site data, or data from nearby oil and gas wells, available as Commission well information or information sourced from commercial data vendors such as Acumap or Geosout.

The above geological marker-based framework applies only to the "subject area". For reference, "subject area" is defined in Section 51 or the Water Sustainability Regulation, and consists of the area east of the Laramide Disturbed Belt boundary (see map). Outside of the "subject area", the "base of usable groundwater" is considered to be 600 m below the ground surface.

Note the technical guidance for determining the "base of usable groundwater" outlined in this section may not be suitable for locations of shallow gas potential or known areas of artesian groundwater pressures. The Commission should be contacted in such cases regarding proposed well drilling and completion.

The Commission may request permit holders to submit documentation of the qualified professional's determination of the "base of usable groundwater".

Laramide Belt Boundary and "Subject Area" for Defining "Base of Usable Groundwater" Using the Geological Marker Based Approach



Appendix F: Facility Changes Requiring an Amendment

The following lists equipment and examples of facility changes requiring the submission of a facility permit amendment for the addition or removal of temporary or permanent equipment on Crown or private land.

- Amine sweetening package - process gas
- Amine sweetening package - fuel gas
- Bullet - condensate storage
- Bullet - LPG storage
- Capacity - gas/liquids throughput permit increase
- Compressor
- Condensate stabilization unit
- Cooler/heat exchanger
- Debutanizer unit
- Deethanizer unit
- Depropanizer unit
- Dehydrator - glycol (process & fuel gas)
- Dehydrator - molecular sieve
- Flare stack
- Generator - (gas/diesel)
- Permitted H2S increase
- Incinerator
- Meter equipment related to production accounting
- Pump (used to transport hydrocarbon liquid (oil, LPV or HPV) in a pipeline, or pump fresh water)
- Pump jack (gas and electric)
- Process refrigeration unit
- Facility storage (pit or tank)
- Treater - Oil

Appendix G: Facility Changes Where No Amendment or NOI is Needed

The following list includes examples of facility changes that do not require a Notice of Intent or amendment. These changes can be made under the authority of the existing facility permit (if not requiring new land).

- Analyzer
- Blow Case (without compressor)
- Coalescer
- Dehydrator - instrument air
- Field header
- Filter
- Generator - solar/fuel cell
- Generator - thermo electric
- Heater
- Instrument air compressor unit
- Line heater
- Meter - non accounting
- Odourization pot
- Other/miscellaneous - minor
- Piping changes at the facility not impacting measurement or air emissions
- Pump (except those referenced in Appendix F)

Appendix H: Piping and Instrumentation Diagram (P&ID)

Piping and Instrumentation Diagram (P&ID) P&ID must be legible and identify each segment of pipe, including new pipe being built in existing right-of-ways in the project description and piping and instrumentation diagram. The minimum requirements for P&IDs are:

- All pipelines which are part of the permit are shown, including their connections (input and output).
- All segment breaks indicated and segments labelled (by project/segment if known, otherwise by OGC number if known, future input or other regulator if currently no OGC number or project number).
- Facility and pipeline breaks, if applicable, clearly indicated.
- Spec breaks and class location changes indicated.
- Valves, fittings, flanges, etc. shown.
- Risers indicated with locations.
- Flow direction indications/arrows.
- Any equipment or pressure control directly on the pipeline, including setpoints. (Note pressure control can be on the facility drawings, in which case a separate pressure control attachment can be provided).
- Pipeline fluid or fluids, maximum permitted H_2S and MOP.
- Pipeline OD (outside diameter) and WT (wall thickness).
- Drawing cross-references. Indicate on the drawing the line continued on so it is traceable.
- Drawing number, revision number and date.

Riser locations or installations directly supporting the pipeline are considered part of the pipeline and should be included in the pipeline and instrumentation design. Installation types included on a pipeline application include:

- Pump
- Storage vessel/tank
- Regulator
- Riser
- Pressure control/pressure protection valves/devices
- Isolation valves showing the physical location.
  (If applicable, the distance between valves and relation to major water crossings is to be determined)
- Farm taps
- Line heater

- Flaring
- Generator

Anything directly supporting the pipeline is considered part of the pipeline. Installations not included in the list should be shown on the P&ID and may be included as part of the facility application.

Appendix I: Sour Well Information Form

To apply for the de-classification of a special sour well, the permit holder must submit a request via email to OGCDrilling.Production@bcogc.ca, and include the Sour Well Information Form listed below.

Sour Formations

Formation Name	Max H2S Concentration (%)

Critical features

Critical Feature Type	# within Completion EPZ

Max Completion H2S Release Rate (m3/sec)	
Calculated Completion EPZ (km)	
Nearest Occupied Dwelling (km)	
Nearest Urban Centre (km)	
Nearest School (km)	
Nearest Populated Area (km)	
Nearest Populated Area Name	

Appendix J: Benzene Emissions from Glycol Dehydrators

This information sets out the rationale and requirements for controlling the emissions of benzene from glycol dehydrators.

Benzene is classified as a toxic substance under the Canadian Environmental Protection Act and as a group one carcinogen by the International Agency for Research on Cancer. As a non-threshold carcinogen, there is considered to be some health risk at any level of exposure. As a result, benzene emissions must be managed to achieve the lowest levels practicable to minimize human exposure. The health risk posed by benzene is to be managed by reducing human exposure to the extent possible and practicable.

As part of the Benzene Technical Advisory Team (BTAT), the Commission is committed to reducing benzene emissions from glycol dehydrators.

In order to reduce and manage benzene emissions from glycol dehydrators in British Columbia, permit holders must comply with the following requirements:

- Permit holders must ensure all dehydrators meet the following benzene emissions limits:

Date of Installation or Relocation	Benzene Emissions Limit
Prior to January 1, 1999	5 tonnes/yr
a) Greater than 750 m to the nearest permanent resident or public facility	3 tonnes/yr
b) Less than 750 m to the nearest a permanent resident or public facility	
January 1, 1999 to June 30, 2007	3 tonnes/yr
After June 30, 2007	1 tonne/yr

- If more than one dehydrator is located at a facility or lease site, the cumulative benzene emissions for all dehydrators must not exceed the limit of the oldest dehydrator on site. Modifications may be required to existing units to meet the site limit.
- Any new or relocated dehydrators added to an existing site with dehydrators must operate at a maximum benzene emission limit of 1 tonne/yr or less. The cumulative benzene emissions must not exceed the limit of the oldest dehydrator on site.

- For dehydrators that are only in operation for a portion of the year, the benzene emission rate must be prorated.

Permit holders must complete a DEOS (Dehydrator Engineering and Operations Sheet to determine the benzene emissions from each dehydrator. The sheet must be posted at the dehydrator for use by operations staff and inspection by the Commission. The DEOS must be revised once each calendar year or upon a change in operation status of a dehydrator.

Permit holders must complete and submit an annual Dehydrator Benzene Inventory List by email to OGCbenzene.inventory@bcogc.ca by July 1st of each calendar year for the operations of the previous calendar year.

For further clarification and/or information, contact the Commission's Environmental Management Group.