Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick

UPDATED Rules for Industry

Table of Contents

INTRODUCTION

These rules were originally released in February of 2013 in order to support New Brunswick's on-going management of oil and natural gas activities and to ensure that the Province continued to have the tools needed to guide oil and natural gas exploration and extraction in an environmentally responsible manner. They were based on recommendations contained in *Responsible Environmental Management of Oil and Gas Activities in New Brunswick - Recommendations for Public Discussion* (February 15, 2013), which was released for public comment on May 17, 2012. The rules incorporated input received during a subsequent four-month public review period.

The requirements described in this document build upon existing regulations governing the oil and natural gas industry in New Brunswick and for the most part will be implemented as conditions to Approvals and Certificates of Determination issued under existing legislation including the *Oil and Natural Gas Act, Clean Environment Act,* the *Clean Air Act* and the *Clean Water Act.*

THE NEED FOR CONTINUOUS IMPROVEMENT

Developing rules for the responsible environmental management of oil and natural gas activities in New Brunswick is not a one-time activity. Technology relating to unconventional oil and natural gas development is evolving rapidly. In addition, future experience with oil and natural gas activities in New Brunswick and elsewhere may suggest additional responses. To ensure that the Government of New Brunswick continues to have the tools needed to guide New Brunswick's on-going management of oil and natural gas activities in an environmentally responsible manner, these rules were updated in June of 2021.

FIRST NATIONS ENGAGEMENT AND GOVERNMENT'S DUTY TO CONSULT OBLIGATIONS

The Province is legally obligated to consult with First Nations when contemplating an action or decision that may adversely impact Aboriginal and treaty rights as per Section 35 of the *Constitution Act*, *1982*. This legal obligation is known as the Crown's Duty to Consult and the Province recognizes and respects this constitutional responsibility to ensure adequate and appropriate consultation and accommodation.

Proponents are encouraged to reach out and engage with First Nations early on during planning and feasibility phases of a project. This early engagement promotes mutually beneficial relationships and may address concerns that First Nations have, prior to the application process. This may provide opportunities to avoid or minimize adverse impacts to Aboriginal and treaty rights during the planning and development phases.

Proponents may be required to complete an Environmental Impact Assessment prior to advancing their projects. As such, the New Brunswick Department of Aboriginal Affairs' Interim Proponent Guide is a useful tool for providing general advice and guidance on the roles of

Proponents in engagement and consultation activities. Proponents are encouraged to contact government staff for more information on First Nations engagement and the Duty to Consult.

SCOPE

The rules contained in this updated document are intended to apply to oil and natural gas activities and facilities located on either privately owned or provincially owned land. They address all stages of land-based oil and natural gas production from exploration to abandonment; however particular emphasis has been placed on the drilling and completion of oil and natural gas wells, including hydraulic fracturing.

Unless otherwise indicated, these requirements are not intended to apply retroactively to oil and natural gas facilities that have already been approved and constructed.

The information contained in this document is not an exhaustive list of the requirements to be met by proponents of oil and natural gas activities in New Brunswick. Those who undertake oil and natural gas activities in New Brunswick are responsible for meeting all applicable requirements under the relevant legislation.

1.0 ADDRESSING POTENTIAL CONCERNS ASSOCIATED WITH GEOPHYSICAL (SEISMIC) TESTING

Implementing measures to reduce risks to public safety, private property and the environment during seismic testing.

1.1. SETBACKS FOR SEISMIC ENERGY SOURCES

The minimum setback distances between seismic energy sources and structures including water wells are described in Appendix 1.

1.2. PROTECTING SURFACE WATER AND GROUNDWATER

All shot holes must be drilled using methods and materials that are acceptable to the regulator as described in Sections 1.3, 1.4 and 1.5 below.

1.3. ENHANCED MEASURES TO ADDRESS THE RELEASE OF WATER FROM SHOT HOLES

If groundwater is released and comes to the surface as a result of the drilling of a shot hole or detonation of an explosive energy source, the operator must ensure that:
a) all drilling that is in progress is discontinued and the regulator is notified;
b) no explosive charge is loaded into the shot hole;
c) the shot hole is plugged in a manner that is acceptable to the regulator* so that the flow is confined to the aquifer or stratum of origin;
d) step drilling procedures** are implemented for subsequent, adjacent shot hole drilling; and
e) a report on the flowing hole is immediately submitted to the regulator.

*Acceptable methods include those described in the most recent version of Alberta Environment and Parks' Exploration Directive 2006-17, Flowing Holes and Encountering Gas or other methods that have been pre-approved by the regulator.

**Step drilling procedures mean that the depths of subsequent shot holes in the vicinity where the water was encountered must be adjusted as required to avoid further release of water. A detailed description is provided in the above Directive.

1.4. RESPONDING TO GAS ENCOUNTERED IN A SHOT HOLE

If gas (e.g. methane) is encountered during the drilling of a shot hole, the operator must ensure that:
a) the gas is immediately confined to its source or place of origin in a manner that prevents an adverse effect on human health, public safety, property or the environment*; and
b) immediately after the gas has been confined in accordance with clause a), a report is submitted to the regulator.

*Acceptable methods include those described in the most recent version of Alberta Environment and Parks' Development Exploration Directive 2006-17, Flowing Holes and Encountering Gas or other methods that have been pre-approved by the regulator.

1.5 PLUGGING AND ABANDONING SHOT HOLES

The operator of a seismic testing program must ensure that shot holes are abandoned as follows:
a) a plug must be placed in the shot hole at a depth of at least 1 metre below the surface of the ground;
b) at least a 50 cm thickness of a bentonite* sealing product (or an equivalent sealing product that has been approved by the regulator) must be placed on top of the plug, followed by drill cuttings or other material obtained from the shot hole, and thoroughly tamped;
c) all drill cuttings not required to fill the hole must be spread evenly over the ground surrounding the hole; and
d) all wires leading to the charge must be pulled tight and cut level with the surface of the ground after the charge has been detonated.

*Bentonite is a form of clay that expands when exposed to water.

1.6. MISFIRES

An operator must develop and implement a code of practice describing the measures that will be taken, in the event, that an explosive charge fails to detonate. The code of practice must be developed in consultation with Worksafe New Brunswick and the Department of Natural Resources and Energy Development, and must ensure that:
a) all necessary actions are taken so that a charge that failed to detonate does not present a hazard to persons or property; and
b) on completion of a project, the permit holder will report the location of all unexploded charges to the Department of Natural Resources and Energy Development.

2.0 PREVENTING POTENTIAL CONTAMINANTS FROM ESCAPING THE WELL BORE

Maintaining well integrity and reducing the potential for unintentional releases of substances such as fracturing fluids, drilling fluids, flowback water, produced water and natural gas from the horizontal or vertical segments of oil and natural gas wells.

2.1. USE OF PRESCRIBED DRILLING FLUIDS WHEN DRILLING THROUGH SHALLOW (NON-SALINE) GROUNDWATER

The well operator must use air, freshwater, freshwater-based, or another drilling fluid acceptable to the regulator during the drilling of a well until the surface hole has been drilled and all porous strata that contain non-saline groundwater have been isolated from the drilling fluid by the installation and cementing of the surface casing.

2.2. WELL CASING - GENERAL PROVISIONS

The operator must install steel or steel alloy casing that can withstand the forces of tension, collapse and burst to which that casing will be subject during its installation, cementing, subsequent drilling, hydraulic fracturing and oil and natural gas production. The casing must also be designed to withstand other anticipated conditions including corrosion from hydraulic fracturing proppants and subsurface geochemistry. At a minimum the casing must meet the design criteria specified in the most recent version of Directive 010 - Minimum Casing Design Requirements prepared by the Alberta Energy Regulator (AER).

At a minimum, the operator should install casing that is manufactured to the specifications defined in the most recent versions of American Petroleum Institute (API) Specification 5CT, Specification for Casing and Tubing and International Organization for Standardization (ISO) Standard 11960, Steel Pipes for use as Casing or Tubing for Wells. The casing should also meet or exceed the performance standards in the most recent version of API Technical Report TR5C3, Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing.

2.3. WELL CASING - PRESSURE RATING AND AGE

With the exception of the conductor pipe, all casing installed in the well bore that will be subjected to hydraulic fracturing as part of the well completion must have an internal pressure rating that is at least 10% greater than the anticipated maximum pressure to which the casing will be exposed during hydraulic fracturing and the lifetime of the well. If used or reconditioned casing is installed, it must be tested to ensure that it meets API performance requirements for new casing.

If an operator proposes to hydraulically fracture a well five or more years after the casing and cementing was initially installed, then as part of the application for a permit to carry out this activity, the operator must provide evidence to the regulator (such as casing wear logs, cement evaluation logs, an assessment of casing corrosion or mechanical integrity tests) that the well cementing and casing is of sufficient strength and condition to maintain well integrity during the proposed hydraulic fracturing.

2.4. WELL CASING - JOINTS

All joints in casings used in a well bore, including conductor casing but excluding a conductor pipe, must be threaded rather than welded.

Welding at casing bowls must be done in accordance with acceptable welding procedures developed from the most recent versions of:
a) API Specification 6A Specification for Wellhead and Christmas Tree Equipment.
b) Canadian Standards Association (CSA) Standard Z662-15, Oil and Gas Pipeline Systems;

c) National Association of Corrosion Engineers (NACE) Standard MR01-75, Materials for use in H2S-containing Environments in Oil and Gas Production.
d) Section IX of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

Threaded casing and tubing joint connection make-up and torque procedures must meet the specifications defined in the most recent version of API Recommended Practice 5C1, Recommended Practice for Care and Use of Casing and Tubing. For wells that will be completed using hydraulic fracturing, casing torque data must be recorded in the daily tour sheets for any casing or tubing strings that are primary or secondary barriers for hydraulic fracturing operations. This casing torque data must be retained by the operator and made available to the regulator upon request.

All joint connection compounds used by the operator must meet the performance requirement specifications as defined in the most recent versions of API Recommended Practice 5A3, Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements and International Organization for Standardization (ISO) Standard 13678, Evaluation and Testing of Thread Compounds for Use with Casing, Tubing and Line Pipe.

2.5. WELL CASING - SURFACE CASING VENTS

All wells completed to produce oil or natural gas (including wells that are shut in for future production) must be equipped with surface casing vents that leave the annulus between the second casing string and the surface casing open to the atmosphere (except during a pressure test or while conducting maintenance or other work on the well). The intent is to ensure that any build-up of gas pressure in the annulus between the second casing string and the surface casing as a result of a leak can be easily detected and will not result in the flow of gas into the surrounding aquifer or geological formation. In situations where it is desirable to control surface casing vent flow, the operator may choose to install a burst plate or pressure release valve on the casing vent.

Casing vents must have a minimum diameter of 50 mm, extend at least 60 cm above ground, and terminate in the atmosphere in a manner so that any flow is directed either in a downward direction or parallel to the ground. The working pressure rating in kilopascals (kPa) of all parts of the surface casing vent must be at least 25 times the numerical equivalent of the surface casing depth in metres.

The well operator must monitor, report, assess and address surface casing vent flows (SCVFs) in accordance with the requirements described in Appendix 2.

See also "Well Integrity Monitoring at Oil and Natural Gas Wells" under Section 5.0 and "Investigation and Response - Surface Casing Vent Flow, Gas Migration and Stray Gas" elsewhere in this Section.

2.6. WELL CASING - USE OF CONDUCTOR PIPE AND CASING

The operator must install such conductor pipe as is necessary to maintain a stable well bore, prevent groundwater infiltration and keep the unconsolidated surface material in place during drilling operations.

Use of conductor casing to facilitate well control is required when:
a) an operator drills in a location where formation pressures are not known (e.g. when drilling an exploration/delineation well);
b) there is potential to encounter a hydrocarbon-bearing zone during drilling of the surface hole; or
c) the required surface casing depth is greater than 450 metres.

If conductor casing is used to facilitate well control, the conductor casing must be set at a depth of not less than 20m and a Class I diverter system must be installed, in accordance with the most recent version of Alberta Energy Regulator (AER) Directive 036, Drilling Blowout Prevention Requirements and Procedures.

2.7. WELL CASING - SURFACE CASING DEPTH

Surface casing is required for all oil or natural gas wells drilled in New Brunswick and the operator must ensure that the depth of the surface casing extends to the greater of:
a) a depth of at least 25 metres below all porous strata that contain non-saline groundwater as determined by a qualified Professional Engineer or Geoscientist; or
b) a calculated casing depth based on the most recent version of Alberta Energy Regulator (AER) Directive 008, Surface Casing Depth Requirements.

The operator must not use the surface casing string as the production casing string.

Notwithstanding any other provision of this section, the regulator may require the operator to install surface casing to a greater or lesser depth as the regulator considers appropriate to address site specific geology.

Further to the above, the operator must ensure that:
a) the surface casing is set into a competent zone that can withstand the anticipated pore pressure of completing the next drilling section; and
b) the surface casing is run and cemented as soon as possible after the surface hole has been circulated and conditioned.

Surface casing should not extend into zones known to contain shallow gas. In the event that such a zone is encountered before the non-saline groundwater is cased off, the operator must take all necessary action required to get the well under control to prevent formation gas from entering zones of non-saline groundwater. The operator must notify the regulator within 12 hours of such

an event. If a well control incident (kick) occurs while drilling the surface hole, the operator must immediately report the following information to the regulator:
a) the well location;
b) the time and date of occurrence;
c) the depth and duration of occurrence;
d) the kick volume; and
e) the final drilling fluid weight that was required to control occurrence.

2.8. WELL CASING - MINIMUM BARRIER PROTECTION

Casing for all wells subject to hydraulic fracturing must be designed to provide acceptable barrier protection during hydraulic facture stimulation operations. The main purpose of barrier protection is to prevent the loss of well control. Surface casing and casing cement are not considered pressure barriers and must never be exposed to any hydraulic fracture stimulation pressures.

Casing for wells:
a) in a new geological basin, geologic formation or geographic region, as identified by the regulator; or
b) in a known geologic basin, geologic formation or geographic region where there is a major change or shift in hydraulic fracture stimulation design; must be designed to provide both primary and secondary barrier protection during hydraulic fracture stimulation operations through the use of a combination of intermediate casing, production casing, production liner, tubing and/or tie-back string.

The secondary barrier must be designed and installed in a manner that will:
a) provide protection in the event of a mechanical failure of the primary barrier (i.e. the casing/tubing used to transport the fracturing fluids into the formation under pressure) during hydraulic fracture stimulation operations; and
b) provide well control and an ability to repair or replace the primary barrier in the event of a failure of the primary barrier.

2.9. WELL CASING - USE OF PRODUCTION CASING

In wellbores subjected to hydraulic fracturing operations, where intermediate casing is not being installed, production casing must be installed and run to surface.

In wellbores where intermediate casing is installed, the regulator may allow the use of a production liner instead of a production casing to surface. A request for use of a production liner must be made in writing and include supporting documentation showing that the intermediate casing is adequately engineered to ensure that public health and safety and environmental protection would not be compromised.

Where the use of a production liner is approved by the regulator, the operator must install a tie-back string or tubing with downhole mechanical isolation (i.e. packer or polished bore receptacle) in the wellbore for use in all hydraulic fracture stimulation operations.

2.10. WELL CEMENTING - GENERAL PROVISIONS

The casing in an oil or gas well must be sufficiently cemented to:
a) secure the casing in the well bore;
b) effectively control the well, always prevent the upward migration of fluids under all reservoir conditions (i.e. proper cementation of the well casing across vertically impermeable zones and groundwater zones).
c) ensure that all zones containing non-saline groundwater are isolated and sealed off to effectively prevent contamination or depletion of such water; and
d) ensure that all potentially productive zones (zones capable causing annular over-pressurization), or corrosive zones are isolated and sealed off to the extent that such isolation is necessary to prevent vertical migration of fluids or gases behind the casing (e.g. gas flow in the annulus).

At a minimum:
a) all cement must conform to the most recent version of API Specification 10A, Specifications for Cement and Material for Well Cementing or equivalent; and
b) the cement slurry must be prepared in a manner so as to minimize its free water content in accordance with the above API specification.

The density of the cement slurry must be based upon a laboratory free-fluid separation test demonstrating an average fluid loss of no more than 6 millilitres per 250 millilitres of cement tested in accordance with the most recent version of API Recommended Practice 10 B-2, Recommended Practice for Testing Well Cements.

In areas of known shallow gas that could cause poor cement bonding or reduce cement integrity, the operator must investigate the use of gas migration mitigation methods such as cement systems that reduce cement slurry porosity and permeability, improve fluid loss control, and/or build gel strength rapidly.

The regulator may require that a prescribed cement mixture be used in any well or any area, where local conditions suggest that a specific cement mixture is necessary. The regulator may also require any necessary change to the cementing procedure.

Prior to cementing the surface, intermediate and production casings, the well bore must be conditioned to help ensure an adequate cement bond between the casing and the formation.

The cement should be mixed and pumped at a rate and in a flow regime that ensures consistent slurry density and inhibits channelling of the cement in the annulus.

For all casing cementing operations, a well site representative provided by the well operator must remain on site throughout the cementing process and monitor the cementing during the mixing and pumping. During placement of the cement, the well site representative must monitor pump rates to verify they are within design parameters, as to ensure proper displacement efficiency.

Well cementing reports must be retained by the operator for the life of the well and submitted to the regulator on request. The cement reports must include:
a) the volumes of cement pumped;
b) the types of cement used;
c) a description of cement additives that were employed;
d) the dates and times of 7 cementing;
e) cement slurry weights;
f) the volume of cement returns at surface (if any).
g) the estimated or measured cement level in annulus (if no returns); and
h) details of any problems encountered and/or remedial work* that was performed.

**See the "Well Cementing - Locating the Cement Top and Remedial Cementing" subheading elsewhere in this Section.*

2.11. WELL CEMENTING - CENTRALIZERS

All casing must be adequately centralized to position the casing strings within the well bore to assure that a cement sheath surrounds the outside of the casing. The following installation requirements apply:
a) surface casing must be centralized at the top and bottom of the casing and at intervals of 50 metres or closer along the entire casing length; and
b) intermediate and production casing must be centralized at the top and bottom of all productive formations and at intervals of 50 metres or closer through areas that will be cemented and through to the required top of cement.

Additional centralizers must be placed where necessary to ensure that casing strings are centralized in a manner that will provide for proper zonal isolation by the cement.

Centralizers and their placement must also meet the standards set out in the most recent version of API Recommended Practice 10D-2, Recommended Practice for Centralizer Placement and Stop-Collar Testing and the most recent version of API Technical Report 10TR4 Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations.

2.12. WELL CEMENTING - EXTENT OF CONDUCTOR CASING CEMENT

It is required that conductor casing be cemented to its full length and that the drilled diameter of the bore hole be at least 100 millimetres larger than the diameter of the conductor casing. If the cement job fails to retain its integrity, drilling must be suspended, and remedial action must be taken. If a diverter is installed on the conductor casing, it must be cemented along its full length using the circulation method.

2.13. WELL CEMENTING - EXTENT OF SURFACE CASING CEMENT

It is required that surface casing be run and cemented as soon as practicable after the hole has been circulated and conditioned, and that surface casing be cemented along its full length using the circulation method. The use of fillers or additives that reduce the compressive strength of surface casing cement below the minimum required strength (i.e. lignosulfonate, Hydroxyethyl cellulose, or hydroxycarboxylic acids) must be avoided. The required cement volume must be based on calculated hole-size measurements plus a minimum of 50% excess cement, or hole-size measurements, taken from a calliper log plus a minimum of 20% excess cement volume. Flow returns must be visually monitored.

2.14. WELL CEMENTING - EXTENT OF INTERMEDIATE CASING CEMENT

If intermediate casing is installed in an oil or gas well, the intermediate casing must be cemented from the shoe to a point at least 200 metres above the shoe, or if any porous zone is open to the wellbore above the casing shoe, the casing must be cemented from the shoe up to a point at least 200 metres above the top of the shallowest porous zone or to a point at least 50 metres above the shoe of the next shallower casing string. The cementing must be accomplished using the circulation method unless the use of an alternative method is approved by the regulator. The required cement volume must be based on hole-size measurements, taken from a calliper log, plus a minimum of 20% excess cement volume, and the top of cement must be located by a cement top locating log and reported to the regulator.

The use of cement additives or alternatives that enhance the integrity of the cement bond, cement strength or zone containment is permitted.

2.15. WELL CEMENTING - EXTENT OF PRODUCTION CASING CEMENT

It is required that the production casing be cemented from the shoe to a point at least 200 metres above the shoe, or if any porous zone is open to the wellbore above the casing shoe, the casing must be cemented from the shoe up to a point at least 200 metres above the top of the shallowest porous zone or to a point at least 50 metres above the shoe of the next shallower casing string. Cementing must be accomplished using the circulation method unless the use of an alternative method is approved by the regulator. The required cement volume be based on hole-size measurements, taken from a calliper log, plus a minimum of 20% excess cement volume. The top of cement be located by a cement top locating log and reported to the regulator.

When production liners are permitted by the regulator they must be cemented over their entire length. Alternative completion techniques may be acceptable to the regulator if it can be demonstrated that they provide equivalent hydraulic isolation. The required cement volume must be based on hole-size measurements, taken from a calliper log, plus a minimum of 20% excess cement volume.

2.16. WELL CEMENTING - LOCATING THE CEMENT TOP AND REMEDIAL CEMENTING

Surface Casing

If cement returns are not obtained at the surface or if the cement level in the annulus drops below the surface, the results of a cement top log and a proposed remedial cementing plan must be submitted to the regulator for approval.* Remedial cementing in accordance with the approved plan must be achieved prior to drilling the next hole section.

Intermediate Casing

If the required cement top is not achieved, the results of the cement top log and a proposed remedial cementing plan must be submitted to the regulator for approval* prior to its implementation. Remedial cementing in accordance with the approved plan must be achieved prior to drilling the next hole section.

Production Casing

If the required cement top is not achieved, the results of cement top log and a proposed remedial cementing plan must be submitted to the regulator for approval. *The approved plan must be implemented:
a) prior to commencement of hydraulic fracturing operations; or
b) within 60 days of rig release; or
c) prior to the commencement of well completion activities.

**An operator may submit proposed remedial cementing plans to the regulator in advance and the regulator may approve the plans in advancement. Therefore, that the approved plans can be immediately implemented by the operator, as required.*

2.17. WELL CEMENTING - SETTING (WAIT) PERIOD AND REQUIRED STRENGTH

After cement is placed behind any casing installed below the conductor pipe, the operator must not disturb the casing until the cement achieves a minimum compressive strength of 3,500 kPa. The casing must not be disturbed for a minimum of 8 hours. There will be no exceptions to the 8 hour wait time for the surface casing cement.

A pressure test* on casings or liners that will be exposed to hydraulic fracture stimulation pressures must not commence until at least 7 days after the primary cementing operations are completed on those casings or liners.

**See Section 2.21, "Pressure Testing the Well Casing and Surface Equipment," for more information.*

2.18. WELL CEMENTING - TESTING AND EVALUATION

Testing of Cement Characteristics

It is required that tests be made on representative samples of the cement mixtures plus and additives, using the water source that will be used to prepare the slurry. These tests must be conducted using the equipment and procedures adopted by the API, as published in the most recent version of API Recommended Practice 10B Recommended Practice for Testing Well Cements. Test data showing competency of the proposed cement mixture must be kept on file by the operator and furnished to the regulator on request.

Formation Leak-Off Tests (LOT) / Formation Integrity Tests (FIT)

Unless determined otherwise by the regulator, the operator must conduct a formation leak-off or formation integrity test after drilling out below the surface casing shoe and below the intermediate casing shoe in order to:
a) verify the integrity of the cement in the casing annulus at the casing shoe; and
b) determine that formation integrity at the casing shoe is adequate to meet the maximum anticipated well bore pressure throughout the next drilling section and/or at total depth.

Cement Evaluation - General

The regulator may require that the operator evaluate the quality of the cement job, including the cement-to-casing and cement-to-formation bonds. Acceptable cement evaluation logs include radial bond logs or omni-directional bond logs in combination with a cement bond log (CBL). When a cement evaluation log is required as described below, it must be interpreted and signed by a qualified professional. The interpretation must include an opinion as to the ability of the installed cement to serve its intended purpose, including the prevention of migration of fluids within the annulus.

Cement Evaluation - Surface Casing

The operator must run a cement evaluation log or other cement evaluation technique approved by the regulator, to determine the quality of cement outside the surface casing if:
a) there is any reason to doubt the effectiveness of surface casing cementation as evidenced by abnormal monitoring indications during the cementing operation or upon post cement analysis; or
b) a shallow gas zone is encountered prior to the setting of surface casing and the surface casing is set across the gas producing zone. If the cement bond is not adequate to isolate the well bore from non-saline groundwater and prevent the upward migration of fluid within the annulus,

remedial cementing will be required, and a remedial plan must be submitted to the regulator for approval*.

Cement Evaluation - Intermediate Casing

The operator must run a cement evaluation log from the top of the shallowest porous zone to the top of cement in order to determine if hydraulic isolation has been achieved. If the cement bond is not adequate to isolate these zones, remedial cementing will be required, and a remedial plan must be submitted to the regulator for approval* and must be implemented prior to drilling ahead.

Cement Evaluation - Production Casing

Prior to perforating the casing or initiating a hydraulic fracturing program the operator must run a cement evaluation log from the top of the shallowest porous zone to the top of cement in order to determine if hydraulic isolation has been achieved. If the cement bond is not adequate to isolate these zones, remedial cementing will be required. A remedial plan must be submitted to the regulator for approval* and must be implemented prior to commencing hydraulic fracturing.

**An operator may submit proposed remedial cementing plans to the regulator in advance and the regulator may approve the plans in advancement. Therefore, that the approved plans can be immediately implemented by the operator, as required.*

2.19. WELL CEMENTING - WITNESSING AND NOTIFICATION

The operator must notify the regulator at least 24 hours prior to commencement of surface casing cementing. The regulator may also require notification prior to the running and cementing of other casing strings on a case-by-case basis.

A qualified professional (i.e. wellsite supervisor, a representative of a well service company, or other third-party company) must be retained by the well operator to witness the operations and certify in writing that they were conducted in accordance with the approved program.

2.20. CASING AND CEMENTING PLANS

It is required that casing and cementing plans be submitted to the regulator in support of an application to approve a proposed well. These plans must be available at the well site for the duration of casing and cementing operations. Any revisions to the casing and cementing plans made as a result of on-site decisions and must be documented by the operator and immediately submitted to the regulator.

2.21. PRESSURE TESTING THE WELL CASING AND SURFACE EQUIPMENT

Prior to drilling out the surface, intermediate, and production casing, the operator must ensure that the following components are pressure tested: blow-out preventer, casing string, stabbing valve, inside blow-out preventer, lower Kelly valve, choke manifold, bleed-off and kill line and all associated valves in compliance with the most recent version of Alberta Energy Regulator Directive 036, Drilling Blowout Prevention Requirements and Procedures.

Prior to the start of a hydraulic fracturing program, all cemented casing strings and all tubing strings to be utilized in the hydraulic fracturing operations must be tested with fresh water, mud or brine to a pressure not less than 3,500 kPa greater than the anticipated maximum pressure to be experienced during either the hydraulic fracturing or the life of the completion. If at the end of 30 minutes of such testing, the pressure shows a drop of 10% or more from the original test pressure, the regulator must be notified, and hydraulic fracturing must not commence until the relevant condition is corrected. The condition of a casing removed from service in accordance with the preceding sentence will be deemed to be corrected only after the casing demonstrates less than a 10% drop in pressure after being subjected to a subsequent 30-minute pressure test of the type described above.

Prior to commencing a hydraulic fracturing stage and the pumping of hydraulic fracturing fluid, the injection lines manifold, associated valves, fracture head or tree and any other wellhead component or connection not previously tested must be tested with fresh water, mud or brine to a pressure not less than 3,500 kPa greater than the anticipated maximum pressure to be experienced during the hydraulic fracturing with less than a 10 % pressure loss. If, at the end of 30 minutes of such testing, the pressure shows a drop of 10% or more from the original test pressure, the regulator must be notified, and hydraulic fracturing must not commence until the relevant condition is corrected. The condition of a component removed from service in accordance with the preceding sentence will be deemed to be corrected only after the retested component assembly demonstrates less than a 10% drop in pressure after being subjected to a 30-minute pressure test of the type described above.

Records of all pressure tests must be retained by the operator and submitted to the regulator on request.

2.22. HYDRAULIC FRACTURING TREATMENT PLAN AND NOTIFICATION

At least 30 days prior to initiating a hydraulic fracturing program, the operator must submit a fracturing treatment plan to the regulator for review and approval. The plan must include:
a) the date on which the hydraulic fracturing is expected to commence.
b) a profile of the anticipated pressures and fluid volumes for pumping each stage.
c) a description of the planned treatment interval (i.e. location of top and bottom of perforations expressed in both True Vertical Depth and True Measured Depth.

d) the total number of stages and total estimated volume of water* and fracture fluid that will be used for all stages of the hydraulic fracturing operation; and
e) the casing and surface equipment test pressures.

The Plan must also verify that the operator has made contact with any adjacent operators that are drilling, completing or operating an oil or gas well within twice the planned fracture half-length** distance and that arrangements have been made to cooperate through notifications and monitoring of all drilling and completion operations, to reduce the possibility of unintended entry of water, gas, oil, or other formation fluid into a well bore.

The submission must be updated after the hydraulic fracturing program has been completed (to compare the planned characteristics of the hydraulic fracturing program with the actual characteristics) and must be included in the well completion report and submitted to the regulator within 30 days of the conclusion of hydraulic fracturing program.

**See also "Water Management Plan - Water Use Monitoring and Reporting" under Section 6.0 and "Disclosure and Risk Assessment of Fracture Fluid Additives" under Section 11.0.*

***"Fracture Half-length" means the radial distance initiated from the subject well bore to the outer tip of a fracture propagated by fracturing.*

2.23. PRE-FRACTURING CHECK LIST AND CERTIFICATION

An operator of an oil or gas well that will be stimulated using hydraulic fracturing must complete, sign and submit a Pre-Fracturing Checklist and Certification at least 30 days prior to commencement of a hydraulic fracturing program. The checklist must be signed and dated by an authorized representative of the operator. Among other things, the checklist requires the operator to attest that the operator has met or will meet all relevant casing, cementing and pressure testing requirements, and requires the operator to acknowledge its obligations to monitor pressures and notify the regulator and cease the hydraulic fracturing operation as described in Section 2.24, below.

A Pre-Fracturing Checklist and Certification form is included in Appendix 3.

2.24. PRESSURE MONITORING, MAXIMUM ALLOWABLE PRESSURE AND TERMINATION OF FRACTURING IN RESPONSE TO UNEXPECTED EVENTS

The operator must continuously monitor and record the following parameters during each stage of a hydraulic fracturing program:
a) surface injection pressure;
b) slurry rate;
c) proppant concentration;

d) fluid rate; and
e) all annuli pressures (for stimulation operations where there is an intermediate casing, this includes the pressure between the intermediate casing and production casing).

The hydraulic fracturing treatment pressure must not exceed the test pressure of any given component at any time during hydraulic fracturing operations. Differential pressures across the walls of any casing string must not exceed 80% of the casing's API rated minimum internal yield pressure, throughout the hydraulic fracturing treatment.

The operator's records of the pressure monitoring must be submitted to the regulator within 30 days after stimulation operations are complete, unless a more immediate notification is required as described below.

Hydraulic fracturing must be immediately terminated, and the operator must report the occurrence to the regulator within 24 hours if:
a) the pressure limit described above is exceeded; or
b) a volume of 13 fluid circulates to the surface that is in excess of a volume that could reasonably be expected due to temperature and pressure expansion; or
c) the annulus pressure increases by more than 3,500 kPa during stimulation; or
d) any anomalous pressure and/or flow condition is indicated or occurring including a significant deviation from the treatment plan; or
e) an operator has any reason to suspect a failure of a casing, or casing cement, or the lack of isolation of any sources of non-saline groundwater.

If hydraulic fracturing is terminated for any of the reasons described in this Section, the operator must:
a) report to the regulator all details relating to the incident within 15 days of the occurrence; and
b) perform diagnostic testing and if the testing reveals that a failure has occurred, the operator must shut-in the well and isolate the perforated portion of the well casing as soon as is reasonably practical. Hydraulic fracturing must not recommence unless the situation has been resolved to the satisfaction of the regulator.

2.25. CEASING ACTIVITIES WHEN NECESSARY TO PROTECT PUBLIC HEALTH, SAFETY AND THE ENVIRONMENT

If an operator is not able to effectively repair a deficiency in the design, construction, completion or operation of an oil or gas well so as to protect public health, safety and the environment (including but not limited to all sources of non-saline groundwater and all surface waters potentially affected by the well) the operator must cease operations and plug and abandon the well in such a manner that it does not represent a hazard to public health, safety and the environment.

2.26. USE OF CERTIFIED WELL CONTROL PERSONNEL

It is required that the drilling contractor retained by the operator possess a valid first line supervisor's blow-out prevention certificate or well service blow-out prevention certificate issued by a recognized petroleum industry training service (e.g. Energy Safety Canada*) that addresses blow-out prevention and kick control procedures.

The operator must arrange for or provide:
a) a well site representative (other than the rig manager) who is responsible for the supervision of the drilling/servicing operations; and
b) an on-site rig manager who is responsible for the supervision of the drilling/servicing rig.

The well site representative and the rig manager must each possess a valid second line supervisor's certificate in well control procedures, issued by a recognized petroleum industry training service (e.g. Energy Safety Canada).

The well site representative and the rig manager must not supervise drilling or well servicing operations at more than one location simultaneously. The well site representative and the rig manager may travel off-site; however, they must be at all times; capable of returning to the site within a maximum of two hours.

When potential hydrocarbon-bearing zones have been penetrated, either the well-site representative or the rig manager must be on site while tripping in or out of the well. If it becomes necessary to make an unscheduled tripping when neither of these individuals is present, the tripping may commence immediately after contacting the well-site representative or rig manager. The notified individual(s) must return to the well site immediately. During well control situations, both of these individuals must be on site.

If either of the above personnel are found to not possess a valid certificate as described above the regulator may require the operator to suspend drilling operations as soon as it is safe to do so and to require that operations not resume until such persons are replaced with personnel having the required certification are provided.

**Energy Safety Canada is a safety association serving Canada's oil and natural gas industry.*

2.27. REMOTE BLOW OUT PREVENTION ACTUATOR

Blow out prevention equipment installed at wells that will be subject to hydraulic fracturing must include a remote blow-out prevention (BOP) actuator that is:
a) powered by a source other than rig hydraulics; and
b) located at least 25 metres from the wellhead. All lines, valves and fittings between the BOP and the remote actuator and any other actuator must be flame resistant and have a working pressure rating higher than the maximum anticipated wellhead surface pressure.

2.28. ENHANCED BLOW-OUT PREVENTION MEASURES

The Province will enhance its existing blow-out prevention and control measures by adopting and imposing procedures for drilling and well servicing such as those set out in the latest versions of Alberta Energy Regulator (AER) Directive 036, Drilling Blowout Prevention Requirements and Procedures and Directive 037, Service Rig Inspection Manual.

When drilling in areas where shallow methane may be present, adequate safety measures must be taken, including the use of proper well control measures and flare lines or stacks.

2.29. INVESTIGATION AND RESPONSE - SURFACE CASING VENT FLOW, GAS MIGRATION AND STRAY GAS

The Province has developed a set of requirements addressing the investigation of and response to surface casing vent flow, gas migration and stray gas. Additional detail is provided in Appendix 4.

2.30. WELL PLUGGING AND ABANDONMENT

The Province will enhance its well plugging and abandonment requirements by adopting and imposing the procedures set out in the latest version of Alberta Energy Regulator (AER) Directive 020, Well Abandonment.

3.0. ASSESSING GEOLOGICAL CONTAINMENT OUTSIDE THE WELL BORE

Reducing the potential for substances such as fracturing fluids, drilling fluids, and hydrocarbons to reach water wells or the surface via underground fractures, faults, abandoned oil or gas wells, or a confining layer that is otherwise inadequate.

3.1. ASSESSMENT OF INTER-WELLBORE COMMUNICATION PRIOR TO HYDRAULIC FRACTURING

Prior to initiating a hydraulic fracturing program in any oil or gas well, the operator must prepare a fracture assessment (model) of the potential for inter-wellbore communication between the stimulated well and any adjacent producing, shut-in, or abandoned oil or gas wells.

The above assessment must:
a) consider all relevant geological and geophysical information available to the operator; and
b) include a review distance that extends to twice the planned fracture half-length* over the entire wellbore.

The operator must provide to the regulator the results of the fracture model assessment. The fracture model assessment must be:
a) signed by a qualified professional; and
b) provided to the regulator prior to the commencement of the hydraulic fracturing program.

If the above assessment suggests that there is a possibility that the induced fractures will extend to adjacent oil or gas well bore, then hydraulic fracturing will not be permitted to occur unless the proposed hydraulic fracturing program is modified to eliminate this possibility.

**"Fracture half -length" means the radial distance initiated from the subject well bore to the outer tip of a fracture propagated by fracturing.*

3.2. ASSESSMENT OF GEOLOGICAL CONTAINMENT PRIOR TO HYDRAULIC FRACTURING

Prior to initiating a hydraulic fracturing program for the first time in a geologic basin, geologic formation or geographic region as identified by the regulator, the operator must prepare an assessment of the ability of the intervening zone (between the oil or gas-bearing strata and the base of a non-saline groundwater aquifer) to act as a conning layer and contain the hydraulic fracturing treatment and prevent the vertical migration of fracturing fluid, formation water, hydrocarbons or other potential contaminants, to strata that contain non-saline groundwater.

The above assessment must consider all relevant information including but not limited to:
a) Hydraulic gradient, seepage velocity, required travel time, pore storage volume, and geochemistry (solubility, adsorption, etc.).
b) Include an analysis of the mobility of fracturing fluid in the strata between the perforated well casing and strata containing non-saline groundwater.
c) Include an analysis of the location and extent of geological faults (horizontal and vertical) and natural fracture zones, and;
d) Include a review distance that extends to twice the planned fracture half–length* over the entire wellbore.

The operator must consider the results of the above assessment in designing the hydraulic fracturing program so as to ensure that the fracturing fluids, formation water or hydrocarbons will not migrate vertically within a geological formation and thereby come into contact with any strata that contain non-saline groundwater.

The operator must provide to the regulator the results of the geological containment. The assessment must be:
a) signed by a qualified professional; and
b) provided to the regulator prior to the commencement of the hydraulic fracturing program.

**"Fracture half-length" means the radial distance initiated from the subject well bore to the outer tip of a fracture propagated by fracturing.*

3.3. ANALYSIS OF THE RESPONSE OF GEOLOGICAL FORMATIONS TO HYDRAULIC FRACTURING

As part of any well completion activity that involves hydraulic fracturing, the operator must conduct sufficient monitoring and analysis and/or other appropriate surveillance techniques to fully understand the inherent stress regimes in the geological formation and how the formation responded to hydraulic fracturing. Examples of monitoring and analysis include pressure curve analysis including monitoring the casing pressure of offset wellbores, adding chemical tracers to the hydraulic fracturing fluid and monitoring treating pressures while fracturing.
Within 30 days of the completion of a hydraulic fracturing program, the operator must provide evidence that the results of the hydraulic fracturing were as planned.

3.4. RESTRICTIONS AND SPECIAL REQUIREMENTS IN RELATION TO SHALLOW HYDRAULIC FRACTURING

Shallow hydraulic fracturing* is prohibited.

Hydraulic fracturing for oil or gas exploration or production within geologic formations containing non-saline groundwater is prohibited.

**"shallow hydraulic fracturing" means hydraulic fracturing taking place where the target zone is less than 600 metres below the surface (true vertical depth) or at any other depth that may be defined by the regulator based on site-specific geology.*

4.0 MANAGING WASTES AND PREVENTING POTENTIAL CONTAMINANTS FROM ESCAPING THE WELL PAD

Reducing the potential for escape of substances at the surface due to spills, leaks, improper storage and handling of chemicals, and inadequate treatment or disposal of wastes such as flowback water and produced water.

4.1. WELL PAD CONSTRUCTION

Oil and natural gas operators must submit the design of a proposed well pad (proposed gradients, dimensions, types of fill materials to be used, etc.) to the regulator for review and approval prior to well pad construction.

The design and construction of a well pad must incorporate measures to prevent the downward migration of potential contaminants from the surface into underlying soil and groundwater during drilling and hydraulic fracturing. Such measures include but are not limited to secondary containment as described elsewhere in this section.

See also "Storage Tanks, Vessels and Containers", "Run-off Management", and "Access Control" located elsewhere in this section. Well pad location is addressed in Section 9.0

4.2. USE OF CLOSED LOOP DRILL FLUID SYSTEMS

Operators must employ closed loop, pitless systems for the management of drilling fluid when drilling below the surface hole*.

**"surface hole" means the hole that is drilled to allow the installation of the surface casing. As described in Section 2.0, the surface hole must be drilled using air, freshwater based, or another prescribed drilling fluid.*

4.3. EMERGENCY CONTAINMENT OF HYDRAULIC FRACTURING FLUID

An adequately sized, function-tested relief valve and an adequately sized diversion line must be installed and used to divert flow from the casing being used for hydraulic fracturing to a covered, watertight tank, in case of hydraulic fracturing string failure. The relief valve must be set to limit the pressure inside the casing to no more than 95% of the lowest internal yield pressure rating of the casing.

The operator must have a vacuum truck on stand-by with a maximum response time to the well site of one hour during the pumping of hydraulic fracturing fluid into the well bore and during the first 72 hours of the flowback phase.

In the event that: The operator employs a hydraulic fracturing technology that does not involve the use of a fluid that is a liquid at aboveground temperatures and pressures, alternative emergency containment features and procedures may be required by the regulator.

4.4. WASTE MANAGEMENT PLAN

Proponents of oil or gas wells must submit a waste management plan to the regulator for review and approval, prior to commencing operations. The plan must:
a) demonstrate that due consideration* has been given to minimizing and managing waste through recycling and re-use;
b) describe the wastes that will be generated;
c) describe how those wastes will be handled and stored;
d) describe the proposed method(s) and location(s) of waste treatment, re-use, or disposal; and
e) demonstrate compliance with the waste management requirements established by the regulator (Section 4.5 below) and with requirements contained in any conditions attached to permits, approvals or licences issued by the regulator that address waste management.

**"Due consideration" means an evaluation of the technologies that could be used to recycle or reuse the waste(s), in light of the availability of those technologies in the province (whether at the well pad or elsewhere),and the scale of the operation necessary to employ the technologies effectively.*

Planning for waste management in relation to spill response and site restoration is addressed in Appendix 6 and Appendix 17 respectively.

4.5. WASTE MANAGEMENT - GENERAL

The province has developed waste management requirements that must be followed by proponents of oil and natural gas facilities and addressed in preparing the above waste management plan. Topics addressed in the requirements include:
a) sampling and testing (characterization) of waste;
b) protocols for the storage, conveyance, treatment and disposal of specific waste materials;
c) discharge criteria for treated waste; and
d) waste disposal reporting and notification requirements. These requirements are described in Sections 4.6 to 4.10 below and in Appendix 5.

While the approved waste management plans may vary from area to area within the Province as a result of the variability of the wastes and availability of management options, the principles contained in the waste management requirements will be consistently applied for all oil and natural gas producing areas.

4.6. WASTE MANAGEMENT - WASTE CHARACTERIZATION

Liquid and solid wastes generated at a well pad or recovered from a well bore must be identified and characterised and reported to the regulator by the oil or gas well operator.

Once the wastes recovered from or produced by an oil or gas well:
a) that is the first well drilled in a geologic formation or basin; or
b) that is the first well on a well pad, have been fully characterized (samples sent to a laboratory and analyzed), the regulator will determine the frequency of any additional sampling and analysis that may be required to periodically verify the characteristics of the wastes during the time period that they are being produced. The regulator may waive or vary the analytical testing of waste fluids or solids in cases where a consistent and representative baseline of data has previously been established for a standard set of drilling and completion methods and additives in known geology, where the waste is sent to approved facilities.

4.7. WASTE MANAGEMENT - ON SITE DISPOSAL RESTRICTIONS

No on-site disposal of waste is allowed except as explicitly permitted by both the regulator and the landowner. Proposals for on-site disposal will only be considered for materials that are verified to be uncontaminated in accordance with criteria established by the Department of Environment and Local Government. Drill cuttings, for example, if properly segregated, characterised, dewatered and verified to be uncontaminated may be approved for on-site disposal or land spreading. Note that as part of their review of a project under the *Environmental*

Impact Assessment Regulation, the New Brunswick Department of Agriculture, Aquaculture and Fisheries may identify additional requirements if land application of drilling waste is proposed.

Disposal of wastes including drill cuttings, drill fluids or sludge within the annulus of a well is not permitted.

4.8. WASTE MANAGEMENT - FLOWBACK WATER AND PRODUCED WATER

The use of pits for the storage of flowback water or produced water is not permitted. All flowback and produced water recovered from an oil or gas well must be conveyed by piping to covered, water-tight tanks equipped with secondary containment. Tanks and piping used to store and convey flowback and produced water must be constructed of heat and corrosion-resistant materials compatible with operational pressures and with the known or anticipated chemical and physical properties of the water, in accordance with an approved waste management plan.

Recycling is the preferred method of managing flowback water and produced water. This includes the use of strategies and technologies such as blending, filtration, thermal distillation, reverse osmosis or electro-coagulation. If recycling is not proposed the proponent must demonstrate to the satisfaction of the regulator that recycling of flowback and produced water is not feasible.*

Subject to the above, flowback and produced water must be:
a) treated in accordance with an approved waste management plan and placed in appropriate tankage for short term storage prior to re-use either on-site or at another location (e.g. in hydraulic fracture or drilling operations); or
b) transported to an appropriate waste water treatment facility in the province for treatment and disposal or alternative uses (if the use of the receiving facility has been specifically approved by the regulator and subject to the terms and conditions of that approval); or
c) transported to an appropriate, licensed waste treatment and disposal facility outside the province.

Recycled flowback or produced water may not be used for drilling until all strata that contain non-saline groundwater have been isolated from the drilling fluid by the installation and cementing of surface casing.

The duration of on-site storage of flowback water is limited to no more than 90 days from the last day of well completion or servicing operations unless otherwise permitted by the regulator (e.g. if the operator intends to recycle/reuse the water on-site).

**Based on an evaluation of the technologies that could be used to recycle the water, in light of the availability of those technologies in the province (whether at the well pad or elsewhere), and the scale of the operation necessary to employ the technologies effectively.*

4.9. WASTE MANAGEMENT - NATURALLY OCCURRING RADIOACTIVE MATERIALS (NORMs)

Wastes recovered from or produced by an oil or gas well that is the first well drilled in a geologic formation or basin must be tested for NORMs according to the procedures described in Appendix 5 prior to their removal from the well site. The subject wastes include: flowback recovered from an oil or gas well after hydraulic fracturing, fluids recovered during the production phase of an oil or gas well (i.e. produced water), drill cuttings and used drill fluids. Used piping and other equipment that was in contact with the above materials must also be assessed for NORMs prior to its disposal or recycling.

NORMs testing for subsequent locations in the same formation are not necessary unless determined otherwise. The regulator may waive or vary the analytical testing for NORMs at locations where consistent and representative data has previously been established.

Additional details are provided in Appendix 5.

4.10. WASTE MANAGEMENT - USE OF EXISTING WASTE WATER TREATMENT FACILITIES

Disposal of a waste (e.g. flowback or produced water) at an existing (e.g. industrial) waste water treatment facility in New Brunswick will not be permitted unless it has been established that the facility is capable of providing effective treatment. Toward this end, the waste water facility operator, in consultation with the proponent and the regulator must:

a) fully characterize the concentrations of contaminants in the waste fluid; and

b) design and install* any necessary treatment processes to ensure that the waste water treatment system will have sufficient capacity and will be capable of addressing the contaminants found in the waste fluid, without impacting the long-term viability or life span of the waste water treatment system and without causing other negative impacts including but not limited to adverse impacts on the quality of the receiving water.

Downstream water quality monitoring by the owner of the waste water treatment facility will be required by the regulator as a condition of the above-mentioned approval for any wastewater treatment facility that discharges to surface water whether it is an existing or a new purpose-built facility.

**Modification of an existing industrial wastewater treatment facility (i.e. a change in treatment process or increase in treatment capacity) or construction of a new wastewater treatment facility would typically trigger a requirement for registration under the Environmental Impact Assessment Regulation, Clean Environment Act.*

4.11. SPILL PREVENTION, REPORTING AND RESPONSE

Operators of oil and natural gas facilities must develop submit and implement spill prevention, reporting and response plans and must report to the regulator, any non-routine event or occurrence that represents a risk to public safety, public health or the environment. Additional details of spill and leak prevention, reporting and response requirements are provided in Appendix 6.

See also "Investigation and Response to Surface Casing Vent Flow, Gas Migration and Stray Gas" under Section 2.0, "Emergency Containment of Hydraulic Fracturing Fluid" under Section 4.0 and the "Security and Emergency Planning for Oil and Natural Gas Activities" under Section 8.0.

4.12. RUN-OFF MANAGEMENT

Operators of oil or gas wells must implement and maintain best management practices to control the quality and quantity of runoff generated by rainfall and snow melt, in a manner that prevents erosion, and prevents the transport of sediment and other pollutants off-site. Towards this end, the Province has developed requirements for preparing run-off management plans for well pads. The proponents of an oil or gas well must prepare and submit a run-off management plan that is consistent with these requirements.

Additional information is provided in Appendix 7.

4.13. CHEMICAL MANAGEMENT - GENERAL PROVISIONS

Chemical handling and storage requirements and standards are specified in the *General Regulation* under the *Occupational Health and Safety Act** and in conditions attached to Approvals to construct and operate issued under the *Air Quality Regulation, Clean Air Act** and the *Water Quality Regulation, Clean Environment Act**.

**Part VIII of the* General Regulation, Occupational Health and Safety Act *addresses a variety of issues pertaining to the storage and handling of chemicals. In addition, the Department of Environment and Local Government has the ability to establish chemical storage and handling requirements using conditions attached to approvals to construct and operate facilities, issued under the* Air Quality Regulation, Clean Air Act *and the* Water Quality Regulation, Clean Environment Act. *The conditions typically state that the approval holder must ensure that all chemicals stored at the facility are located in a dedicated chemical storage system. The system must be designed to ensure that all chemicals are:*
a) secured and sealed in chemically resistant containers;
b) away from high traffic areas and protected from vehicle impacts;
c) away from electrical panels;
d) in a containment area that has secondary containment adequate to contain 110% of the volume of the largest container, designed to prevent the release or discharge of chemicals to the environment as a result of a spill; and
e) in an area designed to prevent contact between incompatible chemicals.

4.14. CHEMICAL MANAGEMENT – TRANSPORTATION

The transportation of substances and chemicals must be in compliance with the applicable regulations for the transportation of dangerous goods*.

**The General Regulation made under the New Brunswick Transportation of Dangerous Goods Act, adopts the requirements of the federal Transportation of Dangerous Goods Regulations including requirements pertaining to classifications, shipping documents, safety marks, means of containment, training, and emergency response plans.*

See also "Security and Emergency Planning for Oil and Natural Gas Activities" under Section 8.0 and "Vehicular Traffic-Haul Route Planning" under Section 9.0.

4.15. CHEMICAL MANAGEMENT - CHEMICAL INVENTORY

Operators must maintain an inventory of chemicals used or stored at each oil and natural gas facility, including but not limited to fuel and other products used during drilling, completion, and workover operations, including hydraulic fracturing.

Operators maintaining chemical inventories under this section must update these inventories as required throughout the life of an oil and natural gas facility. These records must be maintained in a readily retrievable format at the operator's local field office.

4.16. ACCESS CONTROL

If a well pad will be left unattended, all chemicals including chemical additives used for well stimulation and hydraulic fracturing must be removed from the site or secured from public access.

Plugs, valves or other release mechanisms associated with storage tanks and containers, (excluding fresh water, fire prevention materials and spill response materials) must be locked when not in use, unless the well operator maintains a 24-hour presence at the well pad.

Within 30 days of battery construction, the battery must be equipped with fencing at least two metres high, constructed of small mesh, industrial-weight fencing, and equipped with a gate that is locked when the well site is unattended.

Within 30 days of rig release, the operator must enclose the well head and all associated equipment with a fence suitable for the prevention of tampering with wellhead equipment. The fence must be constructed of small mesh, industrial-weight fencing not less than two metres high and equipped with a gate that is locked when the well is unattended.

4.17. STORAGE TANKS, VESSELS AND CONTAINERS

It is required that storage tanks, vessels or containers associated with an oil and natural gas facility including liquid mixing, storage and staging areas be equipped with secondary containment as described in Appendix 8. All storage tanks must be suitable for the intended use and designed in accordance with standards established by Underwriters Laboratories (UL), the API, or other applicable standards.
Additional requirements pertaining to storage tanks, vessels and containers are provided in Appendix 8.

4.18. ENHANCED PRECAUTIONS FOR SOUR GAS

The Province will review and enhance its existing provisions for assessing the sulphur content of natural gas and managing sour gas, with reference to regulations in other jurisdictions such as British Columbia where sour gas is common*.

**To date no sour gas has been encountered in New Brunswick.*

5.0 MONITORING TO PROTECT WATER QUALITY

Monitoring groundwater and surface water to:
a) verify that the water-related safeguards included in this document are effective; and
b) provide early warning of any problems. Monitoring at oil and natural gas wells to detect problems that may affect water quality.

5.1. WATER WELL TESTING

Water samples from all water wells located within 200 metres of seismic testing (i.e. within 200 metres of a seismic source point) must be collected and analyzed prior to initiating seismic testing.

Water samples must be collected and analyzed from all water wells located within 500 metres of the well pad of an oil or gas well before drilling begins. *When an oil or gas well is proposed on a new or existing well pad, this sampling must take place prior to the commencement of land clearing and well pad construction, or prior to drilling for existing wells pads.*

In addition to the above baseline water quality sampling for private wells, one groundwater monitoring well must be constructed adjacent to the ONG well pad in order to monitor the groundwater quality and quantity. These dedicated monitoring wells are required in order to detect any potential impacts in the shallow/potable aquifer.

The well water samples must be collected by a qualified third-party Engineering or Geoscience firm licensed to practice in New Brunswick (hired by the operator) and must be analyzed by a laboratory accredited by the Canadian Association for Laboratory Accreditation Inc. at the operator’s expense. The purpose of the sampling is to document the water quality of the well before seismic testing or drilling takes place.

Follow-up sampling and testing are also required, so that any potential impacts to water supplies as a result of the seismic testing, well pad construction, drilling, and hydraulic fracturing can be identified and addressed*.

The Province has developed requirements for water well testing in proximity to oil and natural gas activities, identifying the required timing and the parameters that must be analyzed. Details are included in Appendix 9.

**See “Water Supply Replacement or Restoration” in Section 10.2.*

5.2. SURFACE WATER MONITORING

Surface water monitoring by operators is required for well pads located within 150 metres of a watercourse. This monitoring must include:
a) the collection and testing of water samples prior to the commencement of land clearing and well pad construction, at locations upstream and downstream of the well pad;
b) additional sampling and testing at the same locations and for the same parameters during and after well construction and hydraulic fracturing; and
c) such sampling and testing as may be required by the regulator based on subsequent activities taking place at the well pad (e.g. subsequent hydraulic fracturing programs, etc.).

Sample collection must be conducted by a qualified third-party Engineering or Geoscience firm licensed to practice in New Brunswick, hired by the operator and must be analyzed by a laboratory accredited by the Canadian Association for Laboratory Accreditation Inc. at the operator’s expense.

The Province has developed surface water monitoring requirements, including the required timing and the parameters that must be analyzed. Details are provided in Appendix 10.

5.3. WELL INTEGRITY MONITORING AT OIL AND NATURAL GAS WELLS

The operator of an oil or gas well that has been completed to produce oil or natural gas must submit to the regulator for approval, an integrity management and monitoring plan for the well, well pad and related equipment (e.g. the battery) and implement the approved plan. The items that the plan must address include the following as applicable:
a) annulus pressures;
b) changes in well characteristics that could potentially indicate a deficiency in the production casing, intermediate casing, surface casing, casing cement, packers or any other aspect of well integrity necessary to ensure isolation from potable groundwater;
c) a corrosion monitoring program for well casing;
d) testing for surface casing vent flow and gas migration; and

e) checking for damage due to vandalism, off road vehicles, etc.

If the operator has any reason to suspect a leak or deficiency in an oil or gas well or related equipment, then the operator must perform any necessary diagnostic testing to determine whether a leak or deficiency has actually occurred. The diagnostic testing must be done as soon as is reasonably practical after the operator has cause to suspect a leak or deficiency.

See also “Well Casing - Surface Casing Vents” and “Investigation and Response - Surface Casing Vent Flow, Gas Migration and Stray Gas” under Section 2.0 and “Spill Prevention, Reporting and Response” under Section 4.0.

6.0 PROVIDING FOR THE SUSTAINABLE USE OF WATER

Implementing measures in relation to oil and natural gas activities that will reduce freshwater consumption, conserve New Brunswick’s potable water, and require the sustainable use of water by those who undertake oil and natural gas activities.

6.1. WATER MANAGEMENT PLAN

A well operator intending to employ hydraulic fracturing and intending to withdraw or use water from any water source must have a regulator-approved water management plan in place prior to commencing hydraulic fracturing. For long-term drilling and well stimulation programs taking place over a period of more than one year, the water management plan must be submitted on an annual basis.

The plan must describe:
a) the locations of the proposed water sources;
b) the estimated quantities and types of water (surface/ground, fresh/salt, treated or recycled, etc.) that will be required;
c) the potential timing of this use during the year;
d) the planned methods of reusing or treating wastewater*; and
e) the reason why a waterless hydraulic fracturing technology is not being proposed.

The water management plan must also include contingencies for water sourcing should the intended water supply source(s) become unavailable or are denied.

Additional details regarding the issues to be addressed in a Water Management Plan are described in Sections 6.2 to 6.5, below.

**See also the “Waste Management Plan” subheading under Section 4.0*

6.2. WATER MANAGEMENT PLAN - WATER CONSERVATION AND RECYCLING

Recycling and re-use are the preferred methods of managing flowback water. If recycling/re-use is not proposed, the water management plan must demonstrate to the satisfaction of the regulator that recycling and re-use are not feasible*.

**Based on an evaluation of the technologies that could be used to recycle the water, in light of the availability of those technologies in the Province (whether at the well pad or elsewhere), and the scale of the operation necessary to employ the technologies effectively.*

6.3. WATER MANAGEMENT PLAN - HIERARCHY OF PREFERRED WATER SOURCES

In preparing a water management plan, proponents must investigate all potential sources of water and provide a rationale for the proposed choice of water source. All other factors being equal, the proposed water source must be selected according to the following hierarchy in descending order of preference (from most preferred to least preferred):

1. treated/recycled wastewater from municipal or industrial sources, including flowback and produced water from oil or gas wells;
2. ocean water;
3. non-potable groundwater water (e.g. from deep, saline aquifers);
4. dugouts or catchments or other man-made features that capture run-off or rainwater;
5. lakes or watercourses (including municipal water supplies drawn from lakes, watercourses or impoundments); and
6. potable groundwater (including municipal water supplies drawn from groundwater).

In evaluating proposals to utilize a given water source, the regulator will consider information provided by the proponent. The required information includes, but is not limited to, an evaluation of factors such as:
a) the scale, stage and duration of the proposed work;
b) potential for road damage (due to trucking); and
c) implications of the use of salt water and wastewater for the management of flow back water.

If the proponent proposes to use Options 5 or 6, they must justify this decision by stating why the use of other water sources was not proposed. If proposed water use exceeds 50 cubic metres per day, the proponent must also verify the sustainability* of the proposed water supply.

**See "Water Management Plan - Assessment of Proposed Water Sources" below.*

6.4. WATER MANAGEMENT PLAN - ASSESSMENT OF PROPOSED WATER SOURCES

The water management plan must demonstrate that the rate of water withdrawals will not exceed sustainable limits. In particular, the plan must demonstrate that the planned rates and volumes of water use will not cause:
a) non-saline groundwater to become depleted;

b) a progressive lowering of groundwater levels;
c) water quality degradation; or
d) reduction in the quantity of surface water to an extent that would adversely affect wetlands, aquatic habitat, aquatic ecosystems, or other water users.

For proposed water works having a capacity to withdraw groundwater at a rate exceeding 50 cubic metres per day, the regulator will require the completion of a water supply source assessment by the proponent in accordance with its established Water Supply Source Assessment Guidelines. These include:
a) an aquifer testing protocol to evaluate whether or not any proposed water well(s) can provide and sustain the desired yield;
b) a long-term yield and drawdown projection; and
c) an assessment of impacts on other water users.

For proposed withdrawals of surface water* from rivers, lakes and streams, exceeding 50 cubic metres per day the water management plan must include a source assessment providing information that demonstrates that a “pass-by flow” (in-stream flow) will be maintained, calculated on seasonal, site-specific basis to avoid significant adverse environmental impacts including: reduced stream flow, impacts on wetlands, aquatic habitat and ecosystems, and impacts on other water users.

In cases where the same water source (i.e. the same watercourse or aquifer) will be used by more than one operator or by a single operator using more than one water supply system, then the above assessments must be based on cumulative water use.
If the proponent intends to obtain water from a municipal water supply, the water management plan must include an assessment of the impact of the proposed use on the sustainability and reliability of the municipal water supply for its primary use (i.e. the provision of potable drinking water).

**The construction of a surface water intake will require a Watercourse and Wetland Alteration Permit in accordance with the* Watercourse and Wetland Alteration Regulation of the Clean Water Act *and the permit holder will be required to abide by any attached conditions. Surface water intakes located within watersheds that have been designated under the* Watershed Protected Area Designation Order – Clean Water Act *will be required to abide by the requirements contained in Section 6 (o) and (p) of the Order. These sections establish design and location criteria for pumps and related infrastructure.*

6.5. WATER MANAGEMENT PLAN - WATER USE MONITORING AND REPORTING

The Water Management Plan must include a plan to conduct monitoring and recording of water withdrawals (e.g. via a continuous-recording device or a flow meter or other records) and monitoring of in-stream flows at surface water withdrawal locations. Developers and operators of oil or gas wells must report the amount and source of water they use for hydraulic fracturing to the regulator on a monthly basis in a format determined by the regulator. The reports must include daily withdrawal volumes, instream flow measurements and/or water purchases. The report must also include the results of water quality and water level monitoring (water level monitoring only required if groundwater wells are used as source), interpretation of the data and an assessment of any negative impacts that have resulted from groundwater or surface water usage.

7.0 ADDRESSING AIR EMISSIONS INCLUDING GREENHOUSE GASES

Setting emission limits, creating inventories of emission sources, predicting, modelling and monitoring emissions and planning for emission reductions.

7.1. EMISSION LIMITS

The Department of Environment and Local Government currently uses the *Air Quality Regulation, Clean Air Act* to set emission limits for sources of air emissions by attaching conditions to approvals to construct and operate these sources. The regulator intends to continue to rely primarily on objective-based (i.e. outcome-based) emission limits instead of mandating the use of particular emission control practices or technologies. In other words, the operator of an oil or gas facility will be given an emission limit and must decide how best to achieve it. The objective-based emission limits will be set to ensure that:
a) Canadian Ambient Air Quality Standards and other air quality standards established by the Province of New Brunswick will be achieved and;
b) maximum ground level concentrations set out in the *Air Quality Regulation under the Clean Air Act* will not be exceeded.

As is the case with other industrial sources of air emissions, emissions from oil and natural gas activities will be assessed using a range of tools including:
a) inventories of emission sources (locations and estimated emission rates);
b) air quality monitoring at emission sources to verify emission rates;
c) emission dispersion modelling to predict off-site concentrations of emissions; and
d) ambient air quality monitoring to verify predicted off-site concentrations including concentrations from multiple sources.

Additional details are provided in Sections 7.2 to 7.5 (below).

Greenhouse Gasses

The Government of Canada has recently developed and implemented national regulations to reduce methane from the oil and gas sector. These regulations introduce operating and maintenance standards for the upstream oil and natural gas industry. They ensure that fugitive or venting emissions of methane are reduced when there is a higher potential to emit methane. The Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (SOR/2018-66) are enabled under the *Canadian Environmental Protection Act* (CEPA), 1999.

Currently, New Brunswick is regulated under the federal *Greenhouse Gas Pollution Pricing Act.* Under the *Greenhouse Gas Pollution Pricing Act,* industrial emitters are regulated by the federal Output-Based Pricing System (OBPS) which prescribes sectorial GHG emissions intensity limits. For further details on the OBPS, please see section 7.7.

7.2. EMISSION INVENTORY

Proponents of oil and natural gas wells, batteries, gas conditioning plants and compressor stations must submit an emissions inventory that describes predicted emission rates and predicted annual tonnage releases for all emission sources including: boilers and process heaters, flares and incinerators, storage tanks, compressors, pumps, pneumatic controllers, gathering lines, pressurized vessels/flash tanks, dehydrators, and transportation (trucking, etc.). Emission factors such as those prepared by the US Environmental Protection Agency (US EPA) may be used for this purpose. The emissions of interest are:
a) criteria air contaminants*;
b) toxic air pollutants**; and
c) H2S. The inventory should also describe the general locations of stationary emission sources (e.g. stack locations and heights).

Greenhouse Gasses

Project proponents must submit a GHG emissions inventory that describes all predicted annual direct and indirect GHG emissions from the project construction, operational and maintenance, and decommissioning phases.

The submitted GHG emissions inventory shall be consistent with Environment and Climate Change Canada's Technical Guidance on Reporting Greenhouse Gas Emissions, or the National Standard of Canada CAN/CSA-ISO 14064-2:06, or the GHG Protocol for Project Accounting, and/or future New Brunswick standards for quantifying and reporting GHG emissions.

**Criteria air contaminants refer to a group of pollutants defined by Environment Canada that include: sulphur oxides (SOx); nitrogen oxides (NOx); particulate matter (TPM, PM10 and PM 2.5); volatile organic compounds (VOC); carbon monoxide (CO); and ammonia (NH3).*
***Toxic air pollutants are defined in Schedule 1 of the* Canadian Environmental Protection Act *(1999).*

7.3. EMISSION DISPERSION MODELLING

Using information contained in the emission inventory, proponents of oil and natural gas wells, batteries, gas conditioning plants and compressor stations must conduct screening level emission dispersion modelling using basic computer-based models such as those available from the US EPA Support Center for Regulatory Atmospheric Modeling website. Results must be submitted to the regulator.

If warranted by the results of the emission monitoring and screening level dispersion modelling, proponents of more complex and extensive emission sources such as multiple wells and associated infrastructure will be required to apply more sophisticated air quality dispersion modelling capable of addressing the full complexity and extent of the emission sources.

7.4. AIR QUALITY MONITORING AT SOURCE

Operators of oil and natural gas wells, batteries, gas conditioning plants and compressor stations may be required to conduct periodic, site-specific air quality monitoring at their facilities as determined by the regulator. The decision to implement this requirement will be based on the regulator's review of the air emissions inventory, and emission dispersion modelling as described above. Complaints related to air quality may also lead to a requirement for site-specific monitoring.

7.5. AMBIENT AIR QUALITY MONITORING

If predicted emission concentrations at sensitive locations such as residential areas exceed Canadian Ambient Air Quality Standards, or maximum ground level concentrations set out in the *Air Quality Regulation* under the *Clean Air Act,* ambient monitoring may be required in order to determine actual emission concentrations and to aid in the preparation of an emission reduction plan (see Section 7.6, below).

Ambient air quality monitoring may also be required when necessary to determine the cumulative effects of air emissions. The focus of such monitoring would be on the construction and operation of oil and natural gas wells, gas conditioning plants and compressor stations. Ambient air quality monitoring stations will typically not be required at each individual facility location. Instead they would be located at areas where clusters of oil and natural gas activities occur (e.g. several wells and related facilities as described above). The regulator will assess the need for ambient air quality monitoring and will advise facility proponents as to the requirements.

The scope of a given ambient air quality monitoring program will depend on the potential for cumulative air quality impacts including the intensities and types of existing and proposed activities in a given area (e.g. trucking, types of pumps or generators, the presence of other oil or natural gas operators, the presence of other industrial activities, etc.). The program may be required to include any or all of the following components:

a) compilation of calculated emissions showing total pollutant outputs in a given area;
b) ground level impact modelling showing the potential impact on ambient air quality including potential levels of smog-forming chemicals such as ozone;
c) installation of real-time multi-parameter ambient monitoring stations;
d) collection of grab samples;
e) odour monitoring; and
f) upset or occurrence monitoring when odours or other unusual events occur.

7.6. FUGITIVE EMISSIONS MANAGEMENT AND GREENHOUSE GAS (GHG) REDUCTION PLAN

Operators of oil and natural gas wells, batteries, gas conditioning plants and compressor stations must prepare, adopt and follow a fugitive emissions management plan for the construction and operation and abandonment of these facilities including well drilling, well completion and the production gathering and initial processing of oil and natural gas. The plan must describe the emission mitigation measures that will be employed in the design and operation of these facilities. The plan must be prepared and submitted for approval in a manner determined by the regulator.

As part of the above plan, facility operators must:
a) consider alternatives to diesel fuel for drilling rig compressors (e.g. electricity, natural gas) at locations where these alternatives are available (e.g. where an existing electrical distribution system is located adjacent to the well site) when drilling and completing oil and natural gas wells;
b) ensure that venting of gas from the well bore to the atmosphere does not take place as a part of routine operations at oil and natural gas wells (e.g. during well completion). If the gas cannot be captured it must be flared or incinerated;
c) ensure that venting or flaring of gas from production/development wells located in an oil or gas field served by a gas collection system (gathering line) does not take place as part of routine operations (e.g. during well completion). When constructing production/development wells, operators must plan the work in such a manner that gathering lines are in place so that the first well on a pad can initially be flowed into a sales line;
d) employ measures and technologies such as vapour recovery units, 3-way catalysts and/or catalytic oxidizers, low or no bleed pneumatic devices etc., on infrastructure serving production/development wells, to control the release of methane and toxic air pollutants (e.g. benzene, acrolein and formaldehyde) to the atmosphere.

A summary of additional measures that can be employed to reduce air emissions is provided in Appendix 11.

Greenhouse Gas Reduction

Project proponents must incorporate economically achievable GHG mitigation opportunities and best practices to reduce GHG emissions during project phases (construction, operational and maintenance, and decommissioning). Project proponents must incorporate economically achievable best available technologies to reduce the project’s total direct and indirect GHG emissions in all project phases.

Operators of oil and natural gas wells, gas conditioning plants and compressor stations that emit or will emit a combined amount of 25,000 tonnes or greater of GHGs in carbon dioxide equivalent (CO2e) units per year shall prepare and submit a Greenhouse Gas Management Plan to the Department of Environment and Local Government (ELG) in accordance with the Guidelines for Greenhouse Gas Management for Industrial Emitters in New Brunswick, July 2015, or as may be updated from time to time. The Greenhouse Gas Management Plan shall be renewed every 5 years, as a minimum.

Operators of oil and natural gas wells, gas conditioning plants and compressor stations that emit or will emit a combined amount of 25,000 tonnes or greater of GHGs in carbon dioxide equivalent (CO2e) units per year shall prepare and submit an Annual Greenhouse Gas Progress Report to ELG by July 1st of each year, for the previous calendar year, in accordance with the Guidelines for Greenhouse Gas Management for Industrial Emitters in New Brunswick.

7.7. GREENHOUSE GASES - REPORTING EMISSIONS - CARBON PRICING

Reporting Emissions

Operators of oil and natural gas wells, gas conditioning plants and compressor stations that emit a combined amount of 10,000 tonnes or greater of GHGs in carbon dioxide equivalent (CO2e) units per year shall submit a GHG emissions report by June 1st of each year, for the previous calendar year, to the Department of Environment and Local Government (ELG) by means of Environment and Climate Change Canada (ECCC)'s Single Window Information Manager (SWIM). Reporting shall be consistent with ECCC's Greenhouse Gas Emissions Reporting Program (GHGRP). Reporting requirements are published annually in the Canada Gazette, Part 1 under the authority of subsection 46(1) of the *Canadian Environmental Protection Act, 1999* (CEPA 1999).

Carbon Pricing

Carbon pricing in New Brunswick has two parts: (i) a carbon tax on fuels under the *Gasoline and Motive Fuel Tax Act*; and (ii) a provincial Output-Based Pricing System for large industrial emitters under the *Climate Change Act* (Provincial OBPS).

The Provincial OBPS is designed to ensure there is a price incentive for industrial emitters to reduce their GHG emissions while maintaining competitiveness and protecting against carbon leakage. It establishes GHG emission intensity performance standards that New Brunswick facilities emitting greater than 50,000 tonnes of GHGs annually will be required to achieve. A carbon price is applied to emissions which exceed these performance standards. As such, in order to avoid double pricing, facilities subject to the Provincial OBPS receive an exemption from paying the provincial carbon tax under the *Gasoline and Motive Fuel Tax Act*. Industrial facilities emitting 10,000 tonnes a year or more have the option to opt-in to the Provincial OBPS.

Proponents should contact New Brunswick's Climate Change Secretariat for the latest information on Carbon Pricing.

8.0 ADDRESSING PUBLIC SAFETY AND EMERGENCY PLANNING

Planning for public safety and emergency response.

8.1. SECURITY AND EMERGENCY PLANNING FOR OIL AND NATURAL GAS ACTIVITIES

Operators of oil and natural gas activities are required to submit to the regulator an emergency management program compliant with Canadian Standards Association (CSA) Standard Z1600, Emergency Management and Business Continuity Programs* and a security management program compliant with CSA Standard Z246.1:21, Security Management for Petroleum and Natural Gas Industry Systems**. These programs are required in advance of each phase including:

a) exploration;
b) design, construction, start-up and operation of facilities; and
c) abandonment and de-commissioning.

The programs must be scaled to the level of activity taking place and be based on the associated threats, risks, and vulnerabilities.

As part of the above, operators must address security and emergency management risks outside of the physical footprint of their site operations (e.g. transportation systems, material storage locations, etc.) including all off-site activities that take place in support of their operations.

Security and emergency response management planning will sometimes be a combined effort between the operators of oil and natural gas activities and their service contractors. In such cases, operators may attach or include the plans of contractors as an annex to the overall plan, to ensure that the overall scope of the plan is comprehensive.

As part of the security and emergency response planning, each worksite must be clearly identified with a physical description and a 911 address.

Additional details regarding the above requirements are provided in Appendix 12.

**This standard outlines the requirements for a comprehensive emergency management program. Its goal is to establish the elements of a continuous improvement process to develop, implement, maintain, and evaluate emergency management and business continuity programs that address the functions of prevention and mitigation, preparedness, response, and recovery.*

***This standard is designed to address the prevention and management of security risks that could result in a negative impact on people, the environment, assets, and economic stability. See also "Spill Prevention, Reporting and Response" under Section 4.0 and "Investigation and Response - Surface Casing Vent Flow, Gas Migration and Stray Gas" under Section 2.0.*

9.0 PROTECTING COMMUNITIES AND THE ENVIRONMENT

Addressing the challenges that oil and natural gas activities may represent for social and physical environments that are valued by New Brunswickers.

9.1. VEHICULAR TRAFFIC - OVERSIZE/OVERMASS LOADS AND WEIGHT RESTRICTIONS

Oversize/overmass loads and weight restrictions will continue to be managed using special permits issued under the *Motor Vehicle Act.* This means that transporters must ensure that the vehicle configurations they wish to operate in New Brunswick meet the criteria established by the Department of Transportation and Infrastructure, or that they are eligible for special permits that will allow them to operate under specific conditions.

Additional information is provided in Appendix 13.

9.2. VEHICULAR TRAFFIC - HAUL ROUTE PLANNING

The proponent of an oil or gas well or a stratigraphic test well or a hydraulic fracturing program must provide to the regulator an estimate of the volume and duration of the vehicular traffic that would be generated, including the volume, duration and distances of heavy truck movements and maps showing the routes the heavy trucks will travel.

When requested by the regulator, the proponent must also submit for approval a haul route (road use) plan in advance of commencement of movement of equipment or vehicles. The plan must address issues that are identified by the regulator such as the potential impacts of trucking on public safety, existing traffic patterns, the physical condition of roads and related infrastructure, and the environment. The plan must identify any measures necessary to mitigate the impacts of trucking on the foregoing items*. When preparing the plan, the proponent must consult with the Department of Transportation and Infrastructure and/or local road authority and also with the local school district to address the transportation and safety needs of children going to and from school (by car, bus bicycle or on foot). Consultation with communities located along the proposed haul route(s) will also be required.

Where applicable, the above plan must address the cumulative impacts of trucking planned by two or more oil and natural gas companies using the same haul route(s).

**Examples of mitigation that can be employed as part of the above plan are included in Appendix 14.*

Other conditions may apply in the event of oversize or overmass loads. Refer to Appendix 13.

9.3. VEHICULAR TRAFFIC - ROAD USE AGREEMENTS AND ROAD SYSTEM INTEGRITY STUDIES

The proponent of a hydraulic fracturing program must consult with the Department of Transportation and Infrastructure and /or the local road authority to determine whether or not a road use agreement is required*. If required, the agreement must include a mechanism that will be used to:
a) identify areas where upgrades and repairs are required prior to commencement of heavy trucking related to the hydraulic fracturing program (e.g. culverts and bridges that may require reinforcing or upgrading);
b) identify damage to roads and related infrastructure (culverts, bridges, etc.) caused by increased traffic generated by the hydraulic fracturing program; and
c) assign costs for repairs and upgrades to the responsible operator as appropriate.

The above road use agreement must be developed on the basis of a road system integrity study, completed in advance of the commencement of the subject vehicle movements. The road system integrity study must be designed and implemented at the expense of the operator, in consultation with the Department of Transportation and Infrastructure and/or the local road authority. It must include a record of the haul route (video, still photography, field measurements written descriptions, etc.) sufficient to:
a) fully document road conditions prior to the commencement of the hydraulic fracturing program including existing heavy truck traffic;
b) assess the ability of roadways comprising the haul route(s) to accommodate anticipated heavy truck traffic; and
c) identify areas where upgrades and repairs are required prior to commencement of heavy trucking (e.g. culverts or bridges that may require reinforcing or upgrading).

**At its sole discretion, the Department of Transportation and Infrastructure and /or the local road authority may waive the requirement to complete a road use agreement and/or require alternatives to the road use agreement and the road system integrity study, such as the posting of financial securities or the completion of other arrangements that will ensure that the costs of damage or required upgrades to roads and related infrastructure as a result of movements of heavy trucks related to a hydraulic fracturing program will be borne by the operator of the program.*

9.4. NOISE LEVEL LIMITS

The maximum permissible levels of noise resulting from the on-site operations of oil and natural gas facilities (drill rigs, oil and natural gas wells, compressor stations, batteries, gas conditioning plants, etc.) are 50 dBA Leq for the daytime period (7 a.m. to 7 p.m.) and 40 dBA Leq for the night-time (7 p.m. to 7 a.m.). These noise levels apply at the external wall of the nearest noise receptor (e.g. a dwelling or other noise sensitive building). If there is no noise receptor within 1,500 metres, the noise levels apply at a distance of 1,500 metres measured from the centre of the noise source (e.g. the centre of a well pad or compressor station).

The regulator may allow or require adjustments* to the above basic sound levels on the basis of site-specific conditions such as:
a) the duration and nature of the noise-generating activity;
b) the proximity of the noise receptor to other noise-generating activities (e.g. a highway, airport, etc.);
c) the actual ambient** noise levels; and
d) the presence of noise-sensitive natural features such as wildlife habitat.

If a new noise receptor is subsequently constructed near an existing oil and natural gas facility, the permissible sound level is the existing noise level at the location of the new noise receptor, provided that the oil or gas facility is in compliance with the noise level limits described in the preceding paragraphs.

**Examples of such adjustments and the conditions under which they may be used are available in the most recent versions of British Columbia Oil and Gas Commission's Noise Control Best Practices Guideline and Alberta Energy Regulator (AER) Directive 038, Noise Control.*

***The average sound environment in a given area in absence of oil and natural gas facilities.*

9.5. NOISE MITIGATION AND MONITORING

During the construction and operation of oil and natural gas facilities every effort must be taken to reduce noise levels using measures such as those described in Appendix 15. Operators are reminded to consider noise when locating and designing oil and natural gas facilities and when negotiating leases. Operators are encouraged to communicate with near-by landowners to identify existing and potential future noise-sensitive land uses, and to work proactively to minimize potential noise impacts.

If it is proposed to operate a drill rig, an oil or gas well, or a compressor station or a gas conditioning plant within 1,500 metres of any dwelling, daycare, elementary school, middle school, high school, hospital, nursing home or other structure designed for human occupancy*, any necessary noise mitigation measures must be employed to ensure that noise levels do not exceed those described in Section 9.4 during the operation of these facilities.

The above noise impact mitigation measures must be documented in a noise impact assessment and mitigation plan that includes a plan to monitor noise levels during the operation of the oil and natural gas facilities. The noise mitigation plan must be submitted to the regulator for review and approval prior to commencement of operation of the oil and natural gas facilities. All noise complaints received by an operator must be reported to the regulator.

If a noise complaint is received in relation to a compressor station (e.g. at a well pad, gas conditioning plant or a gathering line) that is operating in compliance with the A-weighted (dBA) sound levels described in Section 9.4, the operator must determine if low frequency noise exists in accordance with the methodology described in the most recent version of Alberta Energy

Regulator (AER) Directive 038, Noise Control. If low frequency noise is confirmed to exist and the A-weighted sound level adjusted according the Directive 038 methodology exceeds the limits described in Section 9.4, then the operator must install measures to control low frequency noise. Such measures may include features such as:
a) sound absorptive material and structures;
b) isolation structures and enclosures;
c) broadband frequency silencers; and d) active noise control technology.

Since it is typically more cost effective to design and install such measures at the time of initial construction, the operator is encouraged to assess the potential for low frequency noise as part of the compressor station design process.

**The above provision is intended to establish requirements for buildings that were already in place at the time that an application to allow the oil or gas facility was received by the regulator.*

9.6. VISUAL IMPACT - SCREENING REPORT AND MITIGATION PLAN

The proponent of the following facilities must submit to the regulator a screening report that assesses the potential visual impact:
a) permanent above ground structures (e.g. compressor stations, batteries and gas conditioning plants);
b) flares and exterior lighting at oil or gas wells during their construction, completion and operation; and
c) exterior lighting at stratigraphic test wells.

The screening report must take into consideration the nature of the facility and its location with respect to:
a) dwellings;
b) First Nations communities, lands and culturally significant sites;
c) public roads;
d) parks, campgrounds and other facilities used for tourism and recreation; and
e) other aesthetic resources including: navigable rivers, and cultural resources including but not limited to locations listed in the New Brunswick Register of Historic Places.

The above report should employ a systematic methodology such as:
a) graphic viewshed and line of site profile analysis; or
b) visual simulations and digital viewshed analysis.

In the event that a potential visual impact is identified, the proponent must describe the measures that will be used to mitigate the visual impact. A list of potential visual impact mitigation measures is included in Appendix 16.

9.7. FACILITY SITING RESTRICTIONS AND SETBACKS - GENERAL PROVISIONS

It is required that well pads be located on the most level location obtainable that will accommodate the intended use. Full consideration must be given to locating oil and natural gas facilities in areas that have been previously disturbed whenever possible. Unless otherwise required by an agreement with a landowner, oil and natural gas facilities must be located as far away as possible from property not included in the surface lease. Oil and natural gas facilities must, to the extent practicable, be located to avoid the fragmentation or bisection of forested land and agricultural fields.

The setbacks listed in the following sections do not preclude the possibility that site-specific setbacks from other cultural or natural features and First Nations communities and lands may be required in order to address potential impacts identified during the review of a project under the *Environmental Impact Assessment Regulation*.

Setbacks from critical/sensitive habitats must be taken into consideration during facility siting.

The Department of Natural Resources and Energy Development screens out some lands when issuing calls for tender in relation to licences to search for oil and natural gas. These include national parks, existing and proposed protected natural areas, wellfields and watersheds used for municipal water supplies, First Nation lands and military lands.

The regulator will establish minimum allowable distances between well pads, once additional information on the characteristics of the geology of the oil and natural gas resources in New Brunswick becomes available. The intent will be to ensure that the number of well pads is minimized and the spacing between them is maximized, while allowing for efficient extraction of oil and natural gas.

9.8. PROTECTING FLOOD PRONE AREAS, WETLANDS AND WATERCOURSES

Flood Prone Areas

Gas conditioning plants and compressor stations (including related fill) are not permitted within flood prone areas.

Well pads are not permitted in flood prone areas unless:
a) it is demonstrated to the regulator that the construction can take place without significant changes to existing flood levels and flow velocities;
b) the surface of the well pad is set at an elevation that is above the flood elevation; and
c) access to the well pad is designed to be passable during a flood event.

Pipes and access roads are not be permitted within flood prone areas except as part of a crossing that has received a permit under the *Watercourse and Wetland Alteration Regulation, Clean Water Act**.

Watercourses and Wetlands

Oil or gas well heads are not permitted within 100 metres of a watercourse or a regulated wetland.

Well pads, batteries, gas conditioning plants and compressor stations are not permitted within 30 metres of a watercourse or a regulated wetland or within 100 metres of a provincially significant wetland.

Pipes and access roads are not permitted within 30 metres of a watercourse or a regulated wetland, except as part of a crossing that has received a permit under the *Watercourse and Wetland Alteration Regulation*, *Clean Water Act**.

Proponents of oil and natural gas facilities will be required to identify all potentially affected wetlands at the facility location, regardless of whether they are regulated wetlands or not. Proponents will be expected to make every effort to mitigate impacts to wetlands when siting and designing their facilities.

**A Watercourse and Wetland Alteration Permit is required for alterations including activities involving ground disturbance and/or cutting of trees in or within 30 metres of watercourses and wetlands. For additional information see Watercourse and Wetland Alteration Technical Guidelines, New Brunswick Department of Environment and Local Government, 2012.*

9.9. PROTECTING WATER SUPPLIES

Designated Public Water Supplies

Oil and natural gas facilities are not permitted within or beneath wellfields or watersheds that have been designated under the provisions of the Watershed Protected Area Designation Order or the Wellfield Protected Area Designation Order under the *Clean Water Act.*

The following minimum setbacks also apply. Well pads are not permitted within:
a) 500 metres of the wellhead of any designated public or First Nations water supply well;
b) 250 metres of the shoreline of a reservoir, natural lake or impoundment serving as a designated public water supply; and
c) 250 metres of a surface water intake feeding into a designated public water supply.

The regulator may increase the required setback based on the capacity of the water supply and local hydrogeological characteristics.

Non-Designated Public Water Supplies

The restrictions and setbacks described under “Designated Public Water Supplies” (above) also apply to non-designated water supplies including wells serving public water supplies and wellfields that have been delineated but not yet designated under the above noted Designation Order.

The regulator may establish site-specific well pad siting restrictions and setbacks in relation to an aquifer identified by the Province as capable of providing a significant source of potable groundwater that could be developed into a public water supply in the future.

Other Water Supplies

The following requirements apply to wells or surface water supplying:
a) private water supplies which may be considered private communal (e.g. campgrounds, mobile home parks, residential subdivisions, etc.) or private industrial, commercial, or agricultural, and
b) public and Crown-owned water supplies not included in the sections above (e.g. nursing homes, hospitals, schools, etc.)

Well pads are not permitted within:
a) 500 metres of the wellhead;
b) 250 metres of the shoreline of a reservoir, natural lake or impoundment serving as a water supply; and
c) 250 metres of a surface water intake feeding into a private water supply.

The regulator may increase the required setback based on the capacity of the water supply and local hydrogeological characteristics.

Individual Water Supplies

Well pads are not permitted within 250 metres of a water well or a spring or a reservoir serving as an individual water supply, or within 250 metres of a surface water intake feeding into an individual water supply.

The regulator may increase the required setback based on the capacity of the water supply and local hydrogeological characteristics.

The regulator may allow a reduction in the setback from a water well or a spring or a reservoir or a water intake serving an individual water supply if:
a) the operator is also the owner of the water supply and receives the permission of the regulator; or
b) the operator obtains the written permission of both the owner of the water supply and the regulator.

Identifying Water Supplies

In implementing the requirements of Section 9.9, the proponent of an oil or gas well must make diligent efforts to identify all water supplies in the vicinity of proposed well pads; where "diligent efforts” means field investigations and contact with landowners, First Nations and municipal officials, as well as record searches.

In implementing the requirements of this provision, the proponent of a well pad must make diligent efforts to identify all individual water supplies in the vicinity of proposed well pads; where “diligent efforts” means field investigations and contact with landowners and municipal officials, as well as record searches.

The above provision is intended to establish setbacks from water supplies that were already in place at the time that an application to allow construction of the well pad was received by the regulator.

9.10. REQUIRED DISTANCES FROM BUILDINGS AND OTHER CULTURAL FEATURES

The operator must not locate an oil or gas well head or a battery or a flare end, or a compressor station or a gas conditioning plant within:
a) 500 metres of a daycare, elementary school, middle school, high school, hospital, or nursing home;
b) 250 metres of a dwelling;
c) 250 metres of a place of outdoor public concourse such as a playground, fairground, outdoor theatre or campground; and
d) 100 metres of any other permanent building, railway, pipeline, or public road. Setbacks should also be observed around First Nations communities and lands, as well as recognized culturally significant areas (e.g. ambush site).

The above provision is intended to establish setbacks from structures and cultural features that were already in place at the time that an application to allow the oil or gas facility was received by the regulator.

9.11. SITE RESTORATION

The Province has developed site restoration requirements that must be followed on sites of oil and natural gas facilities that are no longer required. These requirements include:
a) the preparation of a preconstruction site assessment of soil, vegetation, drainage and topography;
b) the restoration of the site in accordance with the pre-construction site assessment, so that the capability of the land to support land uses is similar to that which existed prior to the construction of the oil and natural gas facility; and
c) the preparation of an environmental site assessment including environmental sampling and remediation of soil or groundwater contaminants in accordance with the most recent version of New Brunswick’s Guideline for the Management of Contaminated Sites.

Other than the requirement to conduct an environmental site assessment and remediate environmental contaminants or restore a wetland or watercourse in accordance with the requirements of the regulator, the regulator may waive or amend the above restoration requirements, in accordance with an agreement between a landowner and an oil or gas lease holder. This is provided that the agreement does not conflict with other obligations (e.g. as set out in legislation, or in conditions attached to Approvals, Permits, Licences, Certificates of Determination, etc.).

Additional details regarding site restoration requirements are provided in Appendix 17.

9.12. SITE REMEDIATION STANDARDS FOR CONTAMINANTS

Cleanup of contaminated sites will be governed by the most recent version of New Brunswick's Guideline for the Management of Contaminated Sites.

Under the Province's Property-Based Environmental Information Program, records, including records of the remediation of impacted properties are maintained by the Department of Environment and Local Government.

9.13. ADDRESSING INDUCED SEISMICITY

The proponent of a high volume* hydraulic fracturing program must assess the potential for hydraulic fracturing to induce seismic activity at the earth's surface in excess of 1.0 ML (The Richter Scale). In making this assessment the operator must make use of information sources such as engineering, geologic and geophysical data to assess the geological setting (including pre-existing faults and lineaments) and data on historical seismicity in the area.

Where potential for induced seismicity as defined above is found to exist, the operator of a high-volume hydraulic fracturing program must:
a) evaluate wellbore placement and design to account for local surface and geological conditions (including pre-existing faults and lineaments);
b) prepare onsite personnel to recognize and respond to the induced seismicity; and
c) conduct qualitative or quantitative site-specific monitoring of seismic activity during hydraulic fracturing as required by the regulator.

**"high volume hydraulic fracturing" means a well completion operation in which the volume of injected base fluid exceeds 1000 cubic metres in any single stage of a hydraulic fracturing program.*

10.0 REDUCING FINANCIAL RISKS AND PROTECTING LANDOWNER RIGHTS

Addressing financial risks that may result from oil and gas activities in New Brunswick and recognizing that government has a role to play in protecting the rights of private landowners.

10.1. FINANCIAL SECURITY FOR DAMAGE

Oil and natural gas operators must provide a financial security to protect property owners from the financial impacts of industrial accidents. The financial security must be provided at the time a well licence is granted* and must remain in place during drilling, well development and oil and natural gas production. The portion of the security not drawn upon by the province will be returned to the operator at the time of well abandonment.

The financial security is intended to ensure that funds are available in the event that:
a) certain damage or impairment to property takes place within a specified time and at a specified distance from seismic testing or drilling of oil or gas wells**; and
b) the operator of the forgoing activities does not initiate the required remedial action. The security does not preclude the possible imposition of any applicable fines or penalties in accordance with provincial legislation.

The amount of the security has been set at $20,000 per well. The maximum amount of security will be capped at $500,000 per operator.

The security must be in one of the following forms:
a) a deposit of money;
b) a negotiable bond signed over to the Province of New Brunswick;
c) an irrevocable documentary credit or letter of credit from an institution acceptable to the regulator, which is negotiable only by the regulator; or
d) a bond from a surety company licensed to do business in the Province.

In order for the Province to access the financial security, it will be necessary to establish that damage or impairment to property has in fact occurred, and that the impairment was caused by the oil or gas operator that posted the security. For this reason, a landowner will have had to agree to allow the recording of pre-project information including:
a) water well sampling (see the “Water Well Testing” subheading under Section 5.0); and
b) any other pre-project monitoring or sampling that may be required.

If the regulator draws on the financial security, the operator must “top up” the security so that the full amount of the initial security remains available to the regulator.

The financial security for damage is intended to ensure that funds are available to reimburse the Province for expenses incurred in carrying out remedial action in relation to damage caused by oil and natural gas activities. It does not preclude the possible imposition of any applicable fines or penalties in accordance with provincial legislation.

**A separate financial security covering seismic testing is currently required under the Geophysical Exploration Regulation, Oil and Natural Gas Act.*

***See the “Water Supply Replacement or Restoration” subheading, below.*

10.2. WATER SUPPLY REPLACEMENT OR RESTORATION

If the owner of:

a) a water supply located within 200 metres of a seismic energy source employed by the operator which has been diminished in quality* and/or quantity within 6 months of the use of the seismic energy source; or

b) a water supply located within 500 metres of the well pad of the operator's oil or gas well which has been diminished in quality* and/or quantity after well pad construction and prior to abandonment of the oil or gas well files a complaint regarding diminished water quality or quantity,

Then the operator must:

a) provide a temporary water supply to the impacted well owners for short-term impacts, or repair, remediate, or replace any permanently impacted well(s), which might include, but is not limited to, deepening a well or drilling a new well; or

b) hire a third-party Engineer/Geoscientist (registered to practice in NB by the Association of Professional Engineers and Geoscientists of New Brunswick) to investigate the complaint and submit the results of the investigation to the regulator. If, on the balance of probabilities, it is determined that the operator is responsible for any negative impacts, they will be required to provide a temporary water supply for short-term impacts, or to repair, remediate, or replace any permanently impacted well(s), which might include, but is not limited to, deepening a well or drilling a new well.

If the oil and natural gas operator disputes the need for further investigation or the conclusions of the third-party Engineer/Geoscientist then the Province may draw on the Security to cover the costs of any third-party or any short- or long-term water supply requirements (e.g. temporary water supply, and/or repair, remediation, or replacement of a water supply well).

The Province will not pay to re-establish a water supply and will not draw on the operator's financial security in cases where the owner of the water supply refused to allow water sampling.**

Nothing in this Section is intended to prevent the Regulator from requiring an operator to investigate a complaint using a third-party Engineer/Geoscientist of a water supply located beyond the above noted distances. If the third-party determines that the activities of the operator is the most likely cause of the water supply impacts, then the operator will be required to provide a temporary water supply for short-term impacts, or repair, remediate, or replace any permanently impacted well(s), which might include, but is not limited to, deepening a well or drilling a new well.

Activities of contractors or subcontractors are also subject to the above requirements.

The water supply replacement or restoration requirements will not apply to impacts to a water supply caused by an activity or event that is unrelated to the activities of oil and natural gas operators or their contractors or subcontractors.

**See "diminished in quality" in the Definitions section of this document.*

***The regulator will investigate complaints it receives regarding water supplies regardless of their location with respect to oil and natural gas activities and including situations where sampling in accordance to the "Water Well Testing" subheading of Section 5.0 was not completed.*

10.3. ENHANCED FINANCIAL SECURITY FOR WELL ABANDONMENT

The Province currently requires oil and natural gas well operators to post a financial security that the Province can draw on in the event that an oil or gas well is not properly plugged and abandoned. The amount of the required well abandonment security for individual oil or gas wells is $50,000 per well.

The security must be in one of the following forms:
a) a deposit of money;
b) a negotiable bond signed over to the Province of New Brunswick;
c) an irrevocable documentary credit or letter of credit from an institution acceptable to the regulator, which is negotiable only by the regulator; or
d) a bond from a surety company licensed to do business in the Province.

The security will be returned to the operator if:
a) an application for a well licence is refused by the regulator;
b) the operator transfers a well licence to another operator and the required security is received from the new operator, or
c) the operator abandons the well in accordance with the requirements of the regulator.

10.4. MANDATORY LIABILITY INSURANCE FOR OPERATORS OF OIL AND NATURAL GAS ACTIVITIES

The operators of oil and natural gas activities and facilities must have in place liability insurance in the amount of $10 million per occurrence, to cover incidents caused by them or by their contractors, which results in personal injury or damage to property or the environment. Evidence of such coverage must be provided to the regulator prior to initiating any oil and natural gas activity. The operator must provide notice to the regulator of any changes to their insurance coverage, including cancellation.

10.5. LAND AGENT LICENSING AND STANDARDS OF CONDUCT

Land agents employed by oil and natural gas companies to undertake negotiations with landowners for leases or access agreements must:
a) be members in good standing with the International Right-of-Way Association (IRWA)*; and

b) have completed the IRWA sponsored "Ethics and the Right-of-Way Profession" course 103 which is available online.

The regulator will consider accepting equivalent certifications obtained from other organizations.

**The IRWA has an established code of ethics that must be adopted by all members.*

11.0 SHARING INFORMATION

Ensuring that regulators, industry and all New Brunswickers have access to a common set of accurate information about oil and natural gas activities in New Brunswick.

11.1. PRESCRIBED MINIMUM NOTIFICATION RADIUS FOR EIA DETERMINATION REVIEWS

As part of required public consultation activities for projects that are registered under the *Environmental Impact Assessment Regulation, Clean Environment Act,* prescribed, standardized landowner notification distances have been established for the oil and natural gas facilities as follows:
a) Gas processing plant or compressor station: 3,000 metres;
b) Well pad: 1,800 metres;
c) Gathering line: 200 metres; and
d) New access road: 200 metres.

These minimum notification distances refer to direct, written notification of those who are located in proximity to a proposed oil or gas project and may be adjusted by the regulator according to site specific conditions. Additional details are provided in Appendix 18.

Other public notification activities such as open houses, newspaper notices, notification of elected officials, etc. are typically required in accordance with project-specific criteria established in consultation with the regulator. Additional information is contained in the most recent version of *A Guide to Environmental Impact Assessment in New Brunswick.*

11.2. PRESCRIBED MINIMUM NOTIFICATION RADIUS FOR SEISMIC TESTING

The operator of a seismic testing program must directly notify occupants of all parcels of land located within 400 metres of all seismic source points prior to the initiation of seismic testing. The notification must be provided in writing and must include:
a) the name of the company doing the testing;
b) the 40 company's contact information including a telephone number;
c) a description of the energy source to be used (explosive charge in a shot hole, vibroseis, etc.); and
d) the anticipated date(s) that the seismic testing will take place. The notice must be delivered in such a manner that it will be received no later than 24 hours before the earliest anticipated date of the commencement of seismic testing within a 400-metre radius of the subject property.

11.3. DISCLOSURE AND RISK ASSESSMENT OF FRACTURE FLUID ADDITIVES

On June 23, 2011, Government announced a requirement for oil and natural gas companies to disclose all proposed and actual contents of all fluids and chemicals used in the hydraulic fracturing process. Disclosure requirements are described in Appendix 19. These requirements apply to hydraulic fracturing taking place on or after June 23, 2011 regardless of the date that the well was originally constructed.

The well operator must also submit a risk assessment of fracture fluid additives conducted in accordance with the requirements described in Appendix 19.

11.4. LIAISON COMMITTEES

When proposing to construct one or more new oil and natural gas well pads, a gas conditioning plant or a compressor station the proponent must make a public offer to initiate and participate in a liaison committee with appropriate membership from interested parties (representatives of local governments, watershed groups, landowners, etc.). The purposes of the committee would include:

a) the dissemination of information about the proponent’s or operator’s planned schedule of activities; and

b) discussion of specific local issues, questions or concerns that may arise from time to time. Where appropriate, a committee could include representatives of more than one operator active in the same general location. Once established, a liaison committee must remain in place throughout the operational life of a project, or until the committee members mutually agree that it is no longer required.

APPENDICES

APPENDIX 1: Minimum Setbacks for Seismic Energy Sources

Structure	Non-explosive energy source (metres)	Explosive energy source	
Building or structure with a concrete base, residence, barn, concrete irrigation structure, concrete lined irrigation canal and concrete water pipeline	50	All	180
Water well or artificial water hole, developed spring	100	All	180
Driveway, gateway or buried water pipeline (other than a concrete-lined pipeline)	5	All	15
Buried telephone or telecommunication line	5	All	15
Survey monument	5	All	15
Cemetery	50	All	100
Petroleum or natural gas pipeline (measured from the centre line of the pipeline) and a petroleum or natural gas well	15	> 0 ≤ 2 > 2 ≤ 4 >4 ≤6 >6 ≤8 >8 ≤10 >10 ≤20	35 45 55 64 72 101

APPENDIX 2: Surface Casing Vent Flow (SCVF)/Gas Migration (GM) Testing, Reporting, and Repair

This Appendix should be read in conjunction with Appendix 4: Investigation and Response to Public Safety and Environmental Hazards Resulting from Surface Casing Vent Flow, Gas Migration and Stray Gas.

Surface Casing Vent Flow

Surface Casing Vent Flow (SCVF) is the flow of gas and/or liquid or any combination of gas or liquid out of the annulus between the surface casing and the next inner casing.

A SCVF is serious if there is:
a) vent flow with a stabilized gas flow equal to or greater than 40 cubic metres per day (m3/d) and/or equal to a surface casing vent stabilized shut-in pressure greater than: i) one-half the formation leak-off pressure at the surface casing shoe, or ii) 11 kPa/m* times the surface casing setting depth; or
b) vent flow with hydrogen sulphide (H2S) present; or
c) hydrocarbon liquid (oil) vent flow; or
d) saline water vent flow; or
e) non-saline water vent flow where the surface shut-in pressure is as in (a), (i) or (ii); or
f) vent flow due to wellhead seal failure or casing failure; or
g) vent flow that constitutes a fire, public safety, or environmental hazard.

An SCVF is non-serious if it has not been classified as a serious vent flow.

**The criterion of 11 kPa/m, or half the known formation leak-off pressure, was chosen to avoid exceeding the fracture gradient. The surface shut-in pressure may vary with formation leak-off pressure, density of the fluid in the annulus, depth to fluid, lost circulation zones, or other well conditions that would limit the allowable shut-in pressure.*

Gas Migration

Gas Migration (GM) is a flow of gas that is detectable at surface, outside of the outermost casing string. A GM is serious if there is a fire or public safety hazard or off-lease environmental damage, such as groundwater contamination. A GM is non-serious if it has not been classified as serious migration.

Testing and Reporting Requirements

SCVF

The operator must ensure that each well is checked for evidence of surface casing vent flow:
a) within 90 days of drilling rig release or during initial completion of the well, whichever occurs first;
b) annually throughout the life of the well, and
c) during abandonment of the well.

The regulator must be notified immediately upon detection of serious or non-serious SCVF.

GM

Within 90 days of drilling rig release, operators must test new wells for GM.

If SCVF is detected, a well must also be tested for GM.

The regulator must be notified immediately upon detection of GM.

Casing Failure

If as a result of testing for vent flow or gas migration, a casing failure is discovered, the casing failure must also be reported.

Repair Requirements

The operator of a well determined to have a serious SCVF and/or GM problem as defined above must take immediate action to repair the problem.

Non-serious SCVF/GM problems must be addressed at the time of well abandonment. Should a non-serious SCVF/GM problem escalate to the serious category, the operator must conduct repairs as soon as possible after determining the change in category. An operator may submit to the regulator a request for an extension to the repair deadline, if exceptional circumstances exist. Once an SCVF or GM repair has been attempted, regardless of the repair result, the operator must notify the regulator.

Option 1-Routine Repair Program (Regulator approval not required)

The regulator does not require industry to submit proposed repair programs for routine SCVF/GM repairs, provided that all of the following steps are followed:
a) the source depth or formation of origin is clearly identified;
b) a method acceptable to the regulator is used to determine the source (e.g. gas analysis, noise/temperature surveys, logs, etc.);
c) the SCVF/GM problem is stopped or eliminated by perforating and cementing the casing(s) at or below the source. (Note that pumping of any type of fluid down the surface casing annulus is

NOT an approved repair option);
d) the cement and additives used in the repair program meet the regulator's cement requirements; and
e) the casing is pressure tested to the maximum operating pressure for 10 minutes with no pressure drop recorded.

Option 2-Non-routine Repair Program (Regulator approval required)

If the operator designs a repair program that deviates from the criteria outlined in Option 1 or if the initial attempt was unsuccessful in eliminating the flow, a repair program must be submitted to the regulator for approval prior to implementation.

The program must include all of the following:
a) the method used to identify source of the SCV/GM flow;
b) all relevant logs;
c) casing and cementing details;
d) depth of the base of non-saline groundwater;
e) complete details of the proposed repair program;
f) proposed perforating depth if greater than 10 metres above the identified source; and
g) a summary of any initial (unsuccessful) operations to repair the flow.

Option 3-Deferral of Repair (Regulator approval required)

Approval to defer repairs on serious vent flows must be received before work begins. There are two ways to defer repair of a serious vent flow: a) produce the vent flow; i.e. collect and market the flow as part of the well production (SCVF production); and/or; b) cap the well (capping with pressure).

Additional details are provided below:

SCVF Production - The operator must submit an application to the regulator to produce any serious vent flow. An application is not required to produce a non-serious vent flow.

The application must include detailed information showing that:
a) The source depth or formation of origin has been clearly identified;
b) The operator owns the mineral rights to produce the source formation;
c) The cemented portion of the surface casing or the next casing string covers the deepest known groundwater;
d) The flow has been analyzed and determined to be sweet (0% H2S);
e) A pressure relief device will be installed to ensure that excessive pressure is not exerted below the casing shoe when the system is shut in;
f) A check valve will be installed downstream of the pressure relief device to prevent backflow;
g) The vent flow will be continuously measured and reported on the monthly production reports;

h) The vent flow will be tied in and placed on production within 60 days of receiving approval; and
i) The operator confirms in writing to the regulator the date the vent flow is tied in.

The regulator will rescind the approval to produce if the operator fails to comply with any of the above conditions and will require that the SCVF be repaired immediately.

Capping with Pressure - The objective of any abandonment is to cap the well without pressure remaining on the casing annulus. The regulator will consider an application to cap a well with pressure only after the operator has made serious attempts to completely eliminate any vent flow. The regulator will review all applications to ensure that the operator has considered every other available option to eliminate the problem.

Records Retention

The operator must keep all SCVF/GM testing and repair information on file for the life of the well plus two years.

APPENDIX 3: Pre-Fracturing Checklist and Certification

Instructions for Completing the Pre-Fracture Checklist and Certification

The completed and signed form must be received by the regulator at least 3 business days prior to the commencement of hydraulic fracturing operations.

The operator may conduct hydraulic fracturing operations provided that: 1) all items on the checklist are affirmed by a response of “Yes,” and 2) all other pre-fracture notification requirements are met.

The well owner is prohibited from conducting hydraulic fracturing operations on the well without additional regulator review and approval if a response of “No” is provided to any of the items in the pre-fracture checklist.

Checklist

Well Name and Number (as shown on the well permit):
Well Owner:
Planned commencement date of hydraulic fracturing:

Yes/No	The Pre-stimulation fracturing fluid disclosure and risk assessment requirements have been met (See Appendix 19).
	The Fracturing Treatment Plan and the Casing and Cementing Plan have been submitted.
	The well has been drilled, cased and cemented in accordance with the well permit, the Casing and Cementing Plan, and all other applicable requirements of the regulator.
	The hydraulic fracturing will proceed in accordance with the submitted Fracturing Treatment Plan.
	All depths where fresh water, brine, oil and/or gas were encountered or circulation was lost during drilling operations are recorded on the attached sheet. Additional sheets are attached which describe how any lost circulation zones were addressed.
	The enclosed radial cement bond evaluation log or other regulator-approved evaluation and narrative analysis of such, verifies top of cement location and effective cement bond.
	A representative blend of the cement used for the production casing (or production liner if its use was permitted by the regulator) was tested and found to be of sufficient strength to withstand the maximum anticipated treatment pressure during hydraulic fracturing operations.
	The required pre-fracturing pressure tests of the well bore and surface equipment will be conducted in accordance with the regulator’s requirements and fracturing operations will only commence if the tests are successful. Any unsuccessful test

	will be reported to the regulator and hydraulic fracturing will not commence until the relevant condition is addressed.
	Hydraulic fracturing will be terminated and the regulator will be notified in accordance with the regulator’s requirements.

I hereby affirm that the information provided on this form is true to the best of my knowledge and belief.
Printed or Typed Name and Title of Authorized Representative
Signature, Date

APPENDIX 4: Investigation and Response to Public Safety and Environmental Hazards Resulting from Surface Casing Vent Flow, Gas Migration and Stray Gas

This Appendix should be read in conjunction with Appendix 2: Surface Casing Vent Flow (SCVF)/Gas Migration (GM) Testing, Reporting and Repair, Appendix 6: Spill Prevention, Reporting & Response, and Appendix 12: Security and Emergency Planning for Oil and Natural Gas Activities.

Initial Notification

In the event of an immediate risk to human life or property, emergency services (911) must be notified as a first priority.

When the operator of an oil or gas facility is notified of, discovers or otherwise becomes aware of:
a) a serious gas migration from an oil or gas well; or
b) surface casing vent flow that constitutes a fire, public safety or environmental hazard; or
c) stray gas from any other source at an oil or gas facility, the operator must immediately notify the regulator* and conduct an investigation of the incident. The purpose of the investigation is to determine the nature of the incident, assess the potential for hazards to public health and safety, and mitigate any hazard posed by the concentrations of gas.

Investigation and Additional Notifications

The investigation undertaken by the operator must include the following:
a) if a complaint has been received, a site visit and interview with the complainant to obtain information about the complaint and to assess the reported gas migration incident;
b) a field survey to assess the presence and concentrations of gas and aerial extent of the gas; and
c) if necessary, the establishment of monitoring locations at: i) potential sources, ii) potentially impacted structures, and iii) the subsurface.

If combustible gas is detected inside a building or structure at concentrations equal to or greater than 10% of the Lower Explosive Limit (L.E.L.), the operator must:
a) immediately notify the owner of the building/structure and any occupants, local emergency responders, gas and electric utility companies, police and fire departments and the regulator* and, in conjunction with the regulator and local emergency responders, take measures necessary to ensure public health and safety;
b) initiate mitigation measures necessary to control and prevent further migration; and
c) implement the additional investigation and mitigation measures as provided below.

1. The operator must immediately notify the affected property owner and the regulator* and, in consultation with the regulator, take measures necessary to ensure public health and safety if sustained detectable concentrations of combustible gas are:
   - greater than 1% and less than 10% of the L.E.L., in a building or structure;

- equal to or greater than 25% of the L.E.L. in a water well head space;
- detectable in the soils; or are
- equal to or greater than 7 mg/l dissolved methane in water.

Additional Actions

The regulator may require the operator to take additional actions including but not limited to the following:
a) conduct a field survey to assess the presence and concentrations of combustible gas and the areal extent of the combustible gas in the soils, surface water bodies, water wells, and other potential migration pathways;
b) collect gas and/or water samples at a minimum for molecular and stable carbon and hydrogen isotope analyses from the impacted locations such as water wells, and from potential sources of the migration such as gas wells;
c) conduct an immediate evaluation of the operator's adjacent oil or gas wells to determine well cement and casing integrity and to evaluate the potential mechanism of migration. This evaluation may include assessing pressures for all casing intervals, reviewing records for indications of defective casing or cement, application of cement bond logs, ultrasonic imaging tools, geophysical logs, and other mechanical integrity tests as required. The initial area of assessment must include wells within a radius of 750 metres and may be expanded if required by the regulator;
d) take immediate action to correct any defect in the oil and natural gas wells to mitigate the incident and;
e) establish monitoring locations and monitoring frequency in consultation with the regulator at potential sources, in potentially impacted structures, and the subsurface.

If concentrations of combustible gas as defined under Investigation and Additional Notifications earlier in this Appendix are not detected, the operator must notify the regulator, and conduct additional monitoring if requested by the regulator.

Written Reports

If concentrations of combustible gas are detected inside a building or structure at concentrations equal to or greater than 10% of the L.E.L., the operator and owner must file a report with the regulator by phone and email within 24 hours after the interview with the complainant (if a complaint was made) and field survey of the extent of the gas. Additional daily or weekly reports must be submitted as requested by the regulator.

For all investigated incidents, a final written report documenting the results of the investigation must be submitted to the regulator within 30 days of the close of the incident. The final report must include the following:
a) documentation of all results of the investigation, including analytical data and monitoring results;

b) a description of any operational changes established at the operator's oil and natural gas wells in New Brunswick; and
c) a description of the measures taken by the operator to repair any defects at any of the investigated oil and natural gas wells.

Reports submitted in accordance with this section that contain an analysis of geological or engineering data must be prepared and stamped by a geologist or engineer licensed to operate in New Brunswick.

*The operator or designate must telephone the Department of Environment and Local Government’s Regional Office having jurisdiction until personal contact is made. (Voice mail does not constitute personal contact), and provide all information known about the incident. Outside of office hours, the operator or designate must telephone the Canadian Coast Guard until personal contact is made at 1-800-565-1633.

APPENDIX 5: Waste Management

Those who undertake oil or gas activities must ensure that waste from oil and natural gas exploration, development, operation and decommissioning is properly stored, handled, transported, treated, recycled, or disposed of, to protect public health and prevent adverse environmental impacts to air, water, soil or biological resources. In carrying out oil and natural gas activities, an operator must make every effort to minimize waste generation. An operator must ensure that, in the performance of related oil and natural gas activities, all contractors and subcontractors conducting work on behalf of the operator will, in the conduct of that work, comply with the following requirements and with any approval or permit issued for their operation.

Waste Management Plan

Before a well operator drills, completes, produces from, or plugs a well, the operator must ensure that adequate provision is made for the management of any produced or generated waste, including but not limited to flow back water, produced water, hydrocarbon waste, drilling fluid, completion fluid, sludge, or other chemical waste, by preparing and submitting to the regulator for approval, a waste management plan.

Waste Management Plan Contents

Such plans must include:

a) the type(s) of waste that will be produced;
b) planned storage and handling methods;
c) a proposal for the testing/sampling protocols to be employed to characterize the wastes including an assessment of the receiving environment if direct discharge by the oil and natural gas operator is proposed (e.g. land application in accordance with the terms of this Appendix);
d) planned disposition of the wastes (treated, re-used, recycled or disposed of) and the methods or facilities to be used including the location of any proposed* or existing waste storage, handling, transfer, treatment or disposal facilities;
e) planned transportation methods and facilities (trucking, piping, etc.);
f) identification and permit/approval numbers for any existing storage, handling, transfer, treatment or disposal facilities to be employed;
d) a copy of any certification, product quality assurance or authorization that may be required by other legislation; and
e) other information the regulator may require including but not limited to MSDS sheets.

*Include details of construction and operation of any proposed on-site or off-site facilities if not previously submitted.

Waste Management Plan - Hierarchy of Preferred Waste Management Options

The waste management plan must be based on the following hierarchy in descending order of preference (from most preferred to least preferred):

1. Source reduction: Reduce the quantity and/or toxicity of the waste generated (by improving process efficiencies, etc.);
2. Re-use/Recycling: Employ techniques to reuse the material one or more times or use the waste material for another beneficial use;
3. Treatment: Employ techniques to reduce the volume and/or the toxicity of residual waste that has been unavoidably generated;
4. Proper disposal: Dispose of remaining wastes in ways that minimize adverse impacts to the environment and that protect human health.

Waste Management Plan – Revisions

The operator must revise and resubmit the waste management plan to the regulator for approval annually (for oil and natural gas activities taking place over a period of two or more years) and prior to implementing changes to any practices identified in the approved waste management plan.

Waste Management and Disposal Requirements

<u>Identification and Characterization of Waste</u>

In order to establish appropriate waste management options, wastes must be properly identified and characterised. While re-use and other beneficial uses for wastes are encouraged, wastes proven to meet criteria established by the Department of Environment and Local Government* may be discharged to the environment in accordance with applicable approvals and permits as well as provincial and federal regulations.

For waste fluids, the characterization must take into consideration: a) potential sources of natural contaminants including the geochemical properties of the subsurface geological formations; and b) any additives that will be used in the drilling or completion of the well.

Once the wastes recovered from or produced by an oil or gas well: that is the first well drilled in a geologic formation or basin have been fully characterized (samples sent to a laboratory and analyzed), the regulator will determine the frequency of any additional sampling and analysis that may be required to periodically verify the characteristics of the wastes during the time period that they are being produced. The regulator may waive or vary the analytical testing of waste fluids or solids in cases where a consistent and representative baseline of data has previously been established for a standard set of drilling and completion methods and additives in known geology, where the waste is sent to approved facilities.

**These are a set of criteria based on information assembled from a variety of sources including: a) Health Canada's Guidelines for Canadian Drinking Water Quality; b) CCME's Soil Quality Guidelines for the Protection of Environmental and Human Health; c) CCME's Canada Wide Standards for Petroleum Hydrocarbons in Soil; and d) Health Canada's Canadian Guidelines for the Management of Naturally Occurring Radioactive Materials.*

<u>Waste Storage</u>

To the extent possible, compatible wastes must be stored and managed together. Co-mingled wastes must be managed to accommodate the most restrictive characteristic(s) of those wastes.

Waste should be stored in designated areas and within appropriate tankage or vessels. Storage facilities for waste liquids must incorporate secondary containment.

<u>Onsite Disposal</u>

There must be no on-site disposal of waste except as explicitly approved by both the regulator and the landowner. Proposals for on-site disposal will only be considered for materials that are verified to be uncontaminated in accordance with criteria established by the Department of Environment and Local Government. Drill cuttings, for example, if properly segregated, dewatered, characterised, and found to meet the above criteria may be given consideration by the regulator for on-site disposal or land spreading. Note that the New Brunswick Department of Agriculture, Aquaculture and Fisheries may identify additional requirements if land application of drilling waste is proposed.

Annular disposal of wastes including drill cuttings, drill fluids or sludge is not permitted.

<u>Off-Site Disposal</u>

Any off-site facility accepting waste from the operator must possess, and be operated in accordance with, the applicable permits and approvals for that activity.

<u>Disposal at Regional Landfills</u>

Dewatered solid wastes that are not defined as a hazardous waste* may be taken to a Regional Landfill for disposal. Suitable wastes may include municipal solid waste (kitchen and office wastes etc.), drilling sludges, cuttings and other approved solids. Some of the landfills may accept industrial wastes subject to a waste screening process in which the specific wastes would be characterised and verified to be compatible with their systems. Further details may be obtained from the individual Regional Service Commissions.

*"hazardous waste" means waste material intended for disposal or recycling, that is identified as a hazardous waste by the federal *Export and Import of Hazardous Waste and Hazardous Recyclable Material Regulations*, and/or is included in Class 1 and/or Class 7 of the federal

Transportation of Dangerous Goods Regulations. Oil and natural gas drilling and production wastes that are determined to be hazardous wastes must be characterised and appropriately manifested as such. The wastes must be transported by a licensed hauler to a facility approved by the regulator to accept the material.

Transporting Wastes Off site

For any waste material that is moved off site, the operator must maintain a record of the chemical and physical characteristics of the material, the date and time the fluid or other material left the site, the quantity of fluid or other material, and its intended destination, the date and time the material was accepted at the receiving facility, the name and approval number of the receiving facility and use or intended fate at that destination or receiving facility.

For trucked waste, a suitable waste tracking system must be employed. The system must include record keeping (i.e. weigh slips and a waste manifest system).

Transportation of all waste fluids must be undertaken by a waste transporter with all required licences and approvals and transported in watertight containers or systems.

Disposal Reporting and Notification

A well operator must submit to the regulator a waste disposal report in an electronic format that includes an inventory of wastes produced, the hauler(s) of wastes removed from the facility and the time and date the shipments left the site and the time and date of receipt at the receiving facility, the type(s) of waste, the quantity of waste removed from or stored at the facility, the results of any characterisation, the disposal location(s) by address and/or GPS coordinates and the disposal method(s).

Flowback and Produced Water

An operator must ensure that flowback and/or produced water that is separated from hydrocarbons at an oil or gas well or central facility is metered to determine its quantity and flow rates.

Representative samples of the flowback and produced water from an oil or gas well must be analysed in accordance with parameters established by the Department of Environment and Local Government. If the total thorium or total uranium is found to be in excess of 0.02 mg/l the water must also be tested for the Naturally Occurring Radioactive Materials (NORMs) prior to its removal from the well pad.

The analytical results must be recorded and reported in electronic format to the regulator by the 25th day of the month following the month of production.

Drilling Fluids

Oil based drilling fluids recovered from the drilling operation and separated from the drill cuttings may be: a) treated as required and recycled to appropriate tankage for short term storage; b)re-used for drilling at depths below non-saline aquifers and surface casing; c) transported to an appropriate commercial processing facility in the Province for treatment and disposal or alternative uses, if the receiving facility has been specifically approved by the regulator to accept the drilling fluids and subject to the terms and conditions of that approval; or d)transported to an appropriate licensed commercial processing facility outside of the Province.

Water-based drilling fluids that pass the Microtox ®EC50(15) test at 75% concentration and meet the discharge criteria established by the Department of Environment and Local Government may be discharged to the environment in accordance with an approval. Water-based drilling fluids may also be: a) treated as required and recycled to appropriate tankage for short term storage; b) re-used for drilling at depths below the surface casing; c)transported to an appropriate commercial processing facility in the Province for treatment and disposal or alternative uses if the receiving facility has been specifically approved by the regulator to accept the drilling fluids and subject to the terms and conditions of that approval; or d)transported to an appropriate licensed commercial processing outside of the Province.

Alternative disposal methods for water-based drilling fluids that pass the above noted toxicity test and that meet the discharge criteria established by the Department of Environment and Local Government, may be permitted for some water-based drill fluids subject to any conditions the regulator may identify for the chosen disposal method. These methods include but are not limited to spray irrigation or dust suppression.

Non-toxic Drill Cuttings and Sludge

Dewatered and uncontaminated drill cuttings or sludge that:
a) have been separated from a water-based Bentonitic (Clay) or water-based GelChem (polymeric) drill fluid; and
b) were obtained using or were derived from materials that were determined prior to use to be non-toxic using the Microtox® EC50(15) test at 75% concentration and
c) were not modified in composition during drilling operations, and d)meet the criteria established by the Department of Environment and Local Government without dilution, will be considered for use as a “clean fill” and may be disposed of, subject to the operator’s submission of a waste management plan to the regulator, and the regulator’s approval of the plan. If such disposal is being proposed, the waste management plan should include an analytical and toxicological assessment of the waste, a proposal on the methods to be used in the disposal of the waste, the permission of the receiving facility or landowner(s).

Where approved, drill cuttings or sludge that meet the above “clean fill” criteria may be incorporated as a beneficial amendment into the native soils (e.g. to prevent ponding or erosion) The average thickness of the drill cuttings applied must be no more than 50 mm prior to incorporation and the cuttings must be incorporated to a depth of at least 3 times the application rate within ten (10) days of application. Both the applied drill cuttings and the resulting amended soil must meet the analytical requirements of the CCME soil quality guidelines for the applicable occupancy and the soil must be stabilised against erosion by vegetation or other means.

Where approved, drill cuttings or sludge that meet the above “clean fill” criteria may be used for the construction and maintenance of site access roads, a drill pad or related infrastructure, reclamation of related borrow pits, all subject to any conditions identified by the land owner and the regulator.

The well operator may propose alternative uses for the above “clean fill” materials. For example, some sludges having a low permeability may be appropriate for use in liner applications (e.g. for secondary containment). Proposals will be reviewed on a case-by-case basis.

Other Drill cuttings, Sludge and Drilling Solids

Drilling solids that fail the toxicity testing, or solids from oil-based drill mud are to be transported to a facility approved to accept such waste by the Department of Environment and Local Government, or by a regulator in another jurisdiction.

Petroleum contaminated materials such as drill cuttings, soils, hydraulic fracturing proppants and sludge that:
a) is dewatered; and
b) other than the petroleum parameters, meets the criteria established by the Department of Environment and Local Government may be sent to a commercial soil remediation facility that has been approved by the regulator to receive this material.

Disposal proposals for petroleum contaminated materials that do not meet the above requirements will be reviewed on a case by case basis.

Drill cuttings and sludge that do not meet the criteria established by the Department of Environment and Local Government may be may be taken to a Regional landfill for disposal as an Industrial Waste if: a) The material has a minimum of 15% solids with no free-flowing fluids; b) The material is verified to not be a hazardous waste; and c) There is an agreement with the Regional Service Commission, and the terms of the agreement are satisfied.

Toxicity Testing

The discharge of fluids from oil and natural gas operations, whether from the well pad or a central wastewater treatment facility, must be specifically approved by the Regulator prior to the discharge. The discharge must, prior to discharge, be verified to be non-toxic when evaluated using the following testing protocols.

The Microtox® toxicity test, which uses a luminescent bacterium as the test organism, is the established standard for evaluating the toxicity of drilling fluid additives/mud products and the potential toxicity of drilling wastes. This microbial test is a time-effective and cost-effective alternative to the rainbow trout acute lethality test. Other alternatives may be considered in situations where the luminescent bacteria toxicity test is not suitable for the waste being tested (e.g. because of physical interference or atypical dose response).

If fluids are to be discharged to a freshwater environment, including water with elevated salinity due to current or historical impacts by industry or natural salt deposits, the discharge must also be verified to meet the requirements of the most recent version of EPS 1/RM/13 Biological Test Method: Reference Method for Determining Acute Lethality of Effluents to Rainbow Trout prepared by Environment Canada. EPS 1/RM/13 is the default fish toxicity test method for fluid discharges. When discharging to a marine environment and with the Regulator's specific approval, the discharge must be verified to meet the requirements of the most recent version of EPS 1/RM/10 Acute Lethality Test Using Three spine Stickleback prepared by Environment Canada.

Naturally Occurring Radioactive Material (NORM)

Initial Testing

Wastes recovered from or produced by an oil or gas well must be assessed for NORMs. The extent of the initial testing must, at a minimum, include wastes from a well that is:
a) the first well drilled in a geologic formation or basin; and/or
b) the first well drilled on a well pad. The wastes must be tested for NORMs according to the criteria established by the Department of Environment and Local Government prior to their removal from the well site. Subject wastes include: flowback recovered from an oil or gas well after hydraulic fracturing, fluids recovered during the production phase of an oil or gas well (i.e. produced water), drill cuttings and used drill fluids. In addition, wastes stored in enclosed spaces must be assessed for radon gas as an indicator of potential NORM impacts at the Health Canada residential limit of 200 Becquerels per cubic metre.

The Operator must submit a report outlining the findings of the testing to the Regulator that:
a) states whether NORMs were found in excess of the criteria established by the Department of Environment and Local Government;
b) describes the NORM concentrations; and c) presents a proposal on how the NORM affected materials will be managed. The report must be submitted for review and written approval prior to any NORM-affected materials leaving the site.

Subsequent Testing

If NORMs are detected as a result of the initial testing as described above, on-going (monthly or as determined by the regulator) testing of produced water for NORMs must continue during the production stage.

If NORMs are not detected, as a result of the initial testing as described above, the regulator may waive the requirement for on-going testing of produced water for NORMs during the production phase.

Operator Obligations

Operators must maintain an on-site record of the source, the volume, the results of all analytical testing and the GPS coordinates and physical address of each waste disposal location. Upon the regulator's written request, this information must be provided within five (5) business days, in a format readily reviewable by the regulator.

This discharge of wastewater produced by hydraulic fracturing into a wastewater works that is owned or operated by the Province or by a local government or wastewater commission, is not permitted.

APPENDIX 6: Spill Prevention, Reporting and Response

This Appendix should be read in conjunction with Appendix 2: Surface Casing Vent Flow (SCVF)/Gas Migration (GM) Testing, Reporting and Repair, Appendix 4: Investigation and Response to Public Safety and Environmental Hazards Resulting from Surface Casing Vent Flow, Gas Migration and Stray Gas, and Appendix 8: Storage Tanks, Vessels and Containers.

General

An operator of an oil or gas facility must: a) take all reasonable measures to prevent leaks and spills; b) promptly report to leaks and spills to the regulator as described in this Appendix; and c) repair or address any damage, condition or malfunction likely to cause spillage.

Spill and Leak Prevention

All reasonable spill and leak prevention measures must be employed by the operator during facility construction, operation and decommissioning including but not limited to:

a) use of drip pans where leaks or spills could occur during tank filling operations and where making and breaking hose connections;
b) use of fuelling hoses with check valves to prevent hose drainage after spilling;
c) ensuring that fuel tank filling operations are staffed at the fuelling truck and at the receiving tank if the latter is not visible to the fuelling operator;
d) use of overflow prevention devices;
e) use of diversion dikes, berms, curbing, grading or other equivalent measures to minimize or eliminate surface drainage into tank filling areas;
f) use of curbing or posts around storage tanks to prevent collisions during vehicle ingress and egress;
g) availability of a manual shutoff valve on the fuelling vehicle;
h) inspection and preventive maintenance protocols for storage tanks, vessels and containers, including secondary containment;
i) location of additive containers and transport, mixing and pumping equipment as follows: i) within secondary containment; ii) away from high traffic areas; iii) as far as is practical from surface waters; iv) not in contact with soil or standing water;
j) inspection and preventative maintenance protocols for pumping systems and piping systems, including staffed monitoring points during additive transfer, mixing and pumping activities;
k) during pumping and transfer of flowback water (e.g. from a storage tank to a truck) visual inspection of all interconnecting piping that is not visible to transfer personnel at the truck and tank;
l) protocols for ensuring that incompatible materials such as acids and bases are not held within the same containment area;
m) maintenance of a running inventory of additive products and other chemicals stored and used on-site;

n) use of drip pads or pans where additives and fracturing fluid are transferred from containers to the blending unit, from the blending unit to the pumping equipment and from the pumping equipment to the well;
o) location of storage tanks, vessels and containers within secondary containment, away from high traffic areas and as far as is practical from surface waters; and
p) maintenance of a running inventory of flowback water and other stored fluids

Hydraulic Fracturing Injection Lines

During a hydraulic fracturing program involving the use of sand or other abrasive materials (e.g. as a proppant) injection line manifolds and related valves and piping must be inspected for corrosion and internal abrasion that has the potential to affect their integrity.

Temporary Pipelines

Temporary pipelines (in place for 18 months or less) used to convey fluids other than freshwater must be installed aboveground except where crossings of roads or railways are required.

Temporary pipelines that convey fluids other than fresh water over a watercourse or wetland must not have joints or couplings suspended over the watercourse or wetland and shut off valves must be installed at both sides of the crossing.

Temporary pipelines not in use for more than 72 hours must be depressurized.

Inspection of Secondary Containment Prior to Hydraulic Fracturing

No more than 24 hours before initiating any hydraulic fracturing stage, all secondary containment incorporated in the hydraulic fracturing system must be inspected to ensure that it is in place and in proper working order. The results of this inspection must be recorded and documented by the operator, and available to the regulator upon request.

Spill Response Planning

If a leak or spill occurs, the operator must as soon as practicable, do all of the following:
a) promptly take all appropriate actions to protect public health, safety and the environment;
b) contain and clean up the released substance;
c)remediate any affected land, groundwater or surface water*; and
d)remedy the cause or source of the release.

**Unless otherwise determined by the Department of Environment and Local Government, clean-up of contaminated sites will be governed by the most recent version of New Brunswick's Guideline for the Management of Contaminated Sites.*

For each well or facility, the operator must:
a) develop and maintain an adequate spill response plan;
b) submit the spill response plan to the regulator before beginning operations at the well or facility, and
c) respond to a spill at the well or facility in accordance with the spill response plan.

The Plan must include:
a) identification of a spill response team and employee training on proper spill prevention and response techniques;
b) contact information for spill response resources, the regulator, local emergency services, operators of potentially affected public water supplies etc.;
c) in the event of a spill or release, the operator must immediately implement the emergency response procedures in the above-described emergency response program;
d) in the event of a spill or release the operator must report the incident as described below;
e) disposal of cleanup materials in the same manner as the spilled material;
f) procedures for immediately stopping the source of the spill and containing the liquid until the clean-up is complete;
g) ready availability of appropriate spill containment and clean-up materials and equipment, including oil-containment booms and absorbent material; and
h) proposed disposal location for wastes resulting from the spill response.

Method of Reporting Spills

Initial Verbal Report

If the leak or spill represents an immediate risk to human life or property, emergency services (911) must be called as a first priority.

Subject to the foregoing, immediately after discovering a spill the operator must telephone the Department of Environment and Local Government's Regional Office having jurisdiction until personal contact is made. (Voice mail does not constitute personal contact.) Provide all information known about the spill including but not limited to the type and amount of spilled material. Outside of office hours or if personal contact is not made at the Regional Office, the operator must telephone the Canadian Coast Guard until personal contact is made at 1-800-565-1633.

Region 1 Regional Office (Bathurst)	elg.egl-Region1@gnb.ca
Region 2 Regional Office (Miramichi)	elg.egl-Region2@gnb.ca
Region 3 Regional Office (Moncton)	elg.egl-Region3@gnb.ca
Region 4 Regional Office (Saint John)	elg.egl-Region4@gnb.ca
Region 5 Regional Office (Fredericton)	elg.egl-Region5@gnb.ca
Region 6 Regional Office (Grand Falls)	elg.egl-Region6@gnb.ca
Central Office (Fredericton)	remediation@gnb.ca

The above report must include the following information:
a) the name of caller and telephone number;
b) the name and telephone number of the land owner;
c) the names and telephone numbers of all parties involved (e.g. the well service company, transportation company (if Motor Vehicle Accident, include licence number of vehicle(s)), insurance company, etc.);
d) the property location (civic address, highway number, GPS coordinates, etc.);
e) the substance that was released and the known extent of contamination;
f) the cause and source of the release if known (i.e. storage tanks, industrial activities, land use activities, chemical storage, etc.; and
g) any remedial actions undertaken or planned.

Preliminary Written Report

Within 24 hours of the time of initial verbal report, a preliminary written report must be sent by the operator by electronic mail or hand delivered by the operator to the Department of Environment and Local Government's Regional Office as well as the Department's Central office in Fredericton.

The preliminary written report must clearly communicate all information available about the leak or spill including:
a) the information contained in the initial verbal report, updated as necessary;
b) the quantity/volume of product that has been spilled or released;
c) the cause of the spill or release (i.e. storage tanks leaking/ruptured/overfill, motor vehicle accident, equipment failure, container up-set, etc.);
d) the date and time of the spill or release;
e) whether the spill or release is on-going;
f) where on the property the spill/leak occurred (i.e. above/below ground, on surface soil, on a paved surface, on a public highway/ditch, inside/outside building, near storm or sewer collection manholes);
g) whether vapours are present inside a building
h) distances to nearby watercourses and water wells;
i) whether an odour has been detected in drinking water;
j) what organizations have responded (i.e. fire department, municipal works department, Department of Transportation and Infrastructure, clean-up contractor, etc.);
k) The actions taken or to be taken to minimize, contain or control the contamination (i.e. absorbent material spread, sewers or ditches blocked, clean-up in progress, etc.);
l) the results of any such actions taken; and
m) a description of what was done or will be done to prevent the recurrence of the spill.

Detailed Written Report

Within 5 days of the time of the initial notification, a detailed written report must be sent by the operator by electronic mail or hand delivered by the operator to the Department of Environment and Local Government's applicable Regional Office as well as the Department's Central office in Fredericton. The detailed report must supply any new or updated information regarding the topics addressed in the preliminary written report (above).

Reporting to Landowners

The operator must notify affected third parties (e.g. landowners) of spills as soon as practicable, but not more than twenty-four (24) hours, after discovery. The operator also must make good faith efforts to notify and consult with the affected landowner, prior to commencing operations to clean-up/remediate a spill or release except when a leak or spill represents an immediate risk to human life or property.

As part of spill incident reporting and/or contaminated site management, proof of third-party notification must be submitted to the Regulator in the form of a copy of a sent and received certified letter or an e-mail notification with confirmed acknowledgement of receipt from the third party.

The operator must also notify tenants as necessary to protect their health, safety and property.

If released contaminants are detected within 30 metres of a water well or a potable water supply (e.g. surface water supply) or if there is reasonable cause to suspect that a contaminant may impact a water well or a public or a potable water supply, the operator must notify the affected or potentially affected owner/operator of the water well or water supply immediately following discovery of the release or spill.

Mitigation to Prevent Future Spills

Operators must determine the cause of the leak or spill and to the extent practicable, must implement measures to prevent spills/releases due to similar causes in the future.

Previous Contamination

In the event that previous contamination (i.e. resulting from a past, inactive, previously unknown leak, spill or release due to previous activities of the current operator or others) is encountered or discovered by the operator, the operator must immediately after discovering the contamination telephone the regulator's applicable Regional Office until personal contact is made. (Voice mail does not constitute personal contact) and provide all the information listed under Initial Verbal Report (above).

APPENDIX 7: Run-Off Management for Oil and Natural Gas Well Pads

General Requirements

Oil and natural gas operators must implement and maintain Best Management Practices (BMPs) at all oil and natural gas well pads to control runoff generated by rainfall and snow melt in a manner that prevents soil erosion and transport of sediment and other pollutants off-site. In particular, the BMPs must be designed and installed in such a manner that the velocity of the run-off is controlled as required to prevent erosion both on and off-site and that pollutants are contained on site.

BMPs must be maintained until the well pad is abandoned and final reclamation is achieved. They must be inspected, maintained and repaired, as necessary to ensure that they continue to function as designed.

BMPs must be selected based on site-specific conditions, such as slope, vegetation cover, and proximity to watercourses and wetlands. They may be installed in phases as each portion of the site is constructed.

Run-off Management - Best Management Practices (BMPs) - Construction Phase

Well operators must implement BMPs in accordance with good engineering and environmental protection practices, including measures such as:
a) constructing the well pad in such a way that surface runoff is directed to one or more sedimentation ponds with the ability to also function as an emergency spill containment feature;
b) installing features to remove silt and sediment from run-off, such as straw bales, filter strips, etc.;
c) covering materials and activities and providing stormwater diversion to minimize contact of precipitation and stormwater runoff with materials, wastes, equipment, and activities with potential to result in discharges causing pollution;
d) implementing materials handling and spill prevention procedures and practices;
e) using erosion controls designed to minimize erosion of unpaved and un-vegetated areas, including operational well pads, road surfaces and associated culverts, watercourse and wetland crossings, and cut/fill slopes;
f) implementing inspection, maintenance, and good housekeeping procedures and schedules to facilitate identification of conditions that could cause failures of BMPs. These procedures should include measures for maintaining clean, orderly operations and facilities and should address cleaning and maintenance schedules and waste disposal practices. In conducting inspections and maintenance relative to stormwater runoff, operators must consider seasonal factors, such as winter snow cover and spring runoff from snowmelt, to ensure site conditions and controls are adequate and in place to effectively manage stormwater; and
g) implementing vehicle tracking control practices to control potential sediment discharges from operational roads, well pads, and other unpaved surfaces. Practices could include road and pad

design and maintenance to minimize rutting and tracking, controlling site access, street sweeping or scraping, tracking pads, wash racks, education, or other sediment controls.

Run-off Management - Best Management Practices - Post-Construction Phase

Operators of oil and natural gas facilities must develop and implement a post-construction storm water program. The post-construction storm water program must reflect good faith efforts by operators to select and implement BMPs intended to serve the purposes of this section and may include maintaining in-place some or all of the BMPs installed during the construction phase of the facility. BMPs must be selected to address potential sources of erosion and pollution which may reasonably be expected to affect the quality of discharges associated with the ongoing operation of production facilities during the post-construction and reclamation operation of the facilities.

Pollutant sources that must be addressed by BMPs include:
a) transportation of chemicals and materials, including loading and unloading operations;
b) refuelling of vehicles and equipment;
c) outdoor storage, including storage of chemicals and additives;
d) produced water and drilling fluids storage;
e) outdoor processing activities and machinery;
f) significant dust or particulate generating processes;
g) erosion and vehicle tracking from well pads, road surfaces, and pipelines;
h) waste disposal practices;
i) leaks and spills; and
j) ground-disturbing maintenance activities.

In addition to the foregoing, consideration should be given to the incorporation of drainage features that minimize the amount of site run-off (e.g. interception of overland flow before it reaches the site, etc.)

The post-construction run-off management program and features must be supervised and maintained by the facility operator. Employees and subcontractors must be made aware of the BMPs implemented and maintained at the site and the procedures for reporting and any required maintenance or repairs. Documentation must be available including a description of the BMPs selected to ensure proper implementation, operation, and maintenance. Facility-specific maps, installation specification, and implementation criteria must also be included in the documentation when general operating procedures and descriptions are not adequate to clearly describe the implementation and operation of BMPs.

APPENDIX 8: Storage Tanks, Vessels and Containers

The following requirements apply to storage tanks, vessels and containers at oil and natural gas facilities. With the exception of the prohibition of underground storage tanks at well pads (below), the following requirements do not apply to petroleum storage tanks and systems. Such tanks and systems are regulated in accordance with the *Petroleum Product Storage and Handling Regulation, Clean Environment Act.*

Underground Storage Tanks

The use of underground storage tanks at well pads is not permitted.

Primary Containment

Before a well operator drills, completes, begins production from or plugs an oil or gas well, the operator must ensure that adequate provision is made for the containment of any fluids used, produced or generated at an oil or gas facility including but not limited to oil, gas, fresh water, formation water, drilling fluid, completion fluid, liquid chemicals or liquid waste.

Secondary Containment

All storage tanks, vessels or containers associated with an oil and natural gas facility including tanks, vessels or containers that contain liquids and liquid wastes used, stored or produced during drilling, completion, operation, servicing, or plugging of a well, and including liquid mixing, storage and staging areas must be equipped with secondary containment to ensure that liquids will not migrate off the site in the event of a spill or leak and will be captured at source for clean-up or treatment.

Secondary containment is not required for: a) tanks, vessels or containers used to store freshwater or b) water-tight containers or tanks that contain only drill cuttings with no free-flowing liquids.

<u>Secondary Containment – Design</u>

All above grade tanks must be equipped with secondary containment of sufficient capacity to contain 110% of the capacity of the largest single tank or of all the connected tanks (whichever is greater) within the containment area. The secondary containment must be constructed using a suitable working (surface) layer of soil or gravel, underlain by a protection layer of sand or an appropriate geotextile, underlain by:

a) a composite liner of a minimum sixty (60) mil tensile strength; or

b) a three hundred (300) millimetre of low permeability soil with a maximum hydraulic conductivity in the field of 1 x 10(-7) centimetre per second; or

c) an equivalent liner system approved by the regulator.

Secondary Containment - Supplementary Measures

The regulator may identify additional site-specific secondary containment requirements for hydraulic fracturing if the proposed location or type of operation raises a concern about potential liquid chemical releases that is not, in the regulator's judgment, sufficiently addressed by the above standard requirements.

Tanks, Containers and Vessels

Design

Tanks, containers and vessels including the construction materials, age and condition of the tankage, connections and inter connections, must be inspected by a Professional Engineer licensed to practise in the Province of New Brunswick, in order to verify that the they are appropriate for the intended use. A copy of the engineer's signed and stamped tankage installation report must be kept at the facility location and made available to the regulator on request.

All tanks, containers and vessels must be suitable for the intended use and designed in accordance with Underwriters Laboratories (UL), American Petroleum Institute (API), or other standards as applicable.

Tanks and piping used to store and transport flowback or produced water must be constructed of heat and corrosion-resistant materials compatible with the known or anticipated chemical and physical properties of the water, and operational pressures.

Closed Top Tanks

Where practicable, closed top tanks containing odorous or volatile compounds should not be directly vented to atmosphere. The vent should be directed to an appropriate filter, scrubber system, etc.

Open Top Tanks

Open topped metal tanks should be of durable design (metal) and used only for clean water or non-odorous water-based waste materials. Open top tanks must be maintained with at least one metre of freeboard at all times.

Primary containment for open top tanks containing non-odorous water or water-based drilling fluids may be provided by an impermeable 60 mil tensile strength liner (i.e. corrugated steel ring with a synthetic liner) if the design and installation is certified by a Professional Engineer licensed to practice in New Brunswick.

APPENDIX 9: Water Well Testing in Relation to Oil and Natural Gas Activities

Water Well Sampling

Oil and natural gas (ONG) operators wishing to engage in hydrocarbon exploration, development and production in New Brunswick must arrange and pay for the testing of all water wells located:

- within a minimum distance of 200 metres of an energy source used for seismic testing; and
- within a minimum distance of 500 metres* from the edge of a well pad for oil or natural gas drilling.

**The Department of Natural Resources and Energy Development (DNRED) and/or the Department of Environment and Local Government (DELG) may require a larger sampling radius and/or additional water quality testing parameters as warranted by local conditions or hydrogeology.*

All oil and natural gas companies operating in the Province of New Brunswick must adhere to the following procedures for water well testing.

Landowner Permission

Written landowner permission must be obtained by ONG operators prior to collecting and testing samples from water wells.

In the event that a landowner does not grant permission to have their water well tested, a representative of the operator must obtain written confirmation from the landowner that testing is not permitted. If the landowner refuses to provide written confirmation, the representative must document the refusal and must deliver to the landowner a notice verifying that water well samples will not be collected. The operator must retain a copy of the notice and provide it to Department of Environment and Local Government upon request.

Sampling Procedures

Sample collection must be conducted by a qualified third-party Engineering or Geoscience firm licensed to practice in New Brunswick. Sampling must comply with the accredited laboratory's sampling protocols.

For seismic testing, baseline water quality samples (pre-seismic samples) must be collected prior to initializing any seismic testing. Post-seismic water quality samples must be collected within 30 days of the seismic testing. For other oil and natural gas activities, initial water well samples must be collected prior to any land disturbance (i.e. clearing, cutting, well pad construction, etc.). To ensure that the well is not tampered with between the pre-activity sample and follow-up sample collection, the proponent may, with the permission of the well owner, choose to place a tamper-evident seal on the well casing.

Within 30 days of the completion of the final stage of a well completion program (i.e. hydraulic fracturing) on a given well, ONG operators must arrange for the re-testing of the previously sampled water wells.

For the well pad monitoring wells, initial samples must be collected prior to any ONG drilling activities. Follow-up samples must be collected within 30 days of the completion of the final stage of a well completion program (i.e. hydraulic fracturing) on a given well.

If hydraulic fracturing operations do not commence within 90 days of drilling, an additional, intermediate round of water well and well pad monitoring well sampling may be required prior to commencement of hydraulic fracturing operations.

For multi well pads, pre-drilling sampling will be required for each new well, but only if more than 90 days have elapsed since the last post-completion sampling of a previous well drilled on the same pad.

With the exception of confirmatory follow-up samples, individual wells should not be sampled at a greater frequency than once every 90 days.

Analysis of Samples

Pre- and post-seismic water well samples must be tested for inorganic, organic and microbiological parameters.

Pre and post drilling and hydraulic fracturing water well and well pad monitoring well samples must be tested for inorganic, organic, microbiological, and radiological parameters and methane, ethane, and propane. If methane is detected, samples must be collected and analysed using techniques allowing for the differentiation of thermogenic and biogenic methane. Details are provided in the attached parameter lists below.

Samples must be sent to a laboratory accredited by the Canadian Association for Laboratory Accreditation Inc. for testing. The Regulator can modify the required groundwater sampling parameters and/or sampling frequency at any time depending on new information, data, and/or sampling results.

Reporting Results

The third-party Engineering or Geoscience firm must compare test results to current New Brunswick drinking water quality guidelines and mail out individual water quality results to the landowners within five business days of receiving them.

It is the third-party Engineering or Geoscience firm’s responsibility to compare the results of follow-up sampling to pre-activity sampling (i.e. seismic and ONG activities) and identify any parameters that appear, in their professional opinion, to be significantly changed and explain these changes to the landowner in writing.

The third-party Engineering or Geoscience firm must provide the Department of Environment and Local Government Central Office and the relevant Department of Environment and Local Government Regional Office with electronic copies of all landowner communications pertaining to well water quality so that the Department of Environment and Local Government offices receive these communications at the same time as the landowner. For the purposes of this requirement, the water quality related information includes, but is not limited to, pre and post water quality sampling results and water quality interpretation letters.

In addition, the third-party Engineering or Geoscience firm must provide to the Department of Environment and Local Government with all well pad monitoring well water quality results and data comparison and interpretation.

If the sampling results indicate that the water poses a significant human health risk as determined by criteria set by the Department of Health (i.e. presence of total coliform and E. Coli), the third-party Engineering or Geoscience firm must notify the landowner (or the occupant consuming the water) the same day that the results are available and advise them of the risks of consuming their water.

The third-party Engineering or Geoscience firm must notify the Department of Public Safety (i.e. Health Inspector) once they have contacted the landowner and/or occupant. (Note: with exception of bacteriological samples collected from outside taps, any additional follow-up sampling and analysis resulting from pre-seismic water quality issues will be the responsibility of the landowner).

Confidentiality

Test results will be considered confidential and will not be disclosed publicly without the written consent of the well owner except if these results are aggregated with others in a way that does not identify the individual well or landowner.

Final Report

It is the responsibility of the third-party Engineering or Geoscience firm to prepare and submit to the Department of Environment and Local Government a final report detailing the results of the water well sampling program within 90 days of the completion of the program. This report should provide an overview of the sampling program, a summary of the results of pre and post activity sampling, and the reporting procedures used.

Complaints

If the owner of a sampled well observes any changes in their well water quality subsequent to oil or gas activities in their area they may register a complaint with the operator. The ONG operator must inform the nearest Department of Environment and Local Government regional office of any complaints.

If it is determined that the ONG operator is most likely responsible for any negative impacts, it will be required to provide a temporary water supply for short-term impacts, or to repair, remediate, or replace any permanently impacted well(s), which might include, but is not limited to, deepening a well or drilling a new well.

SEISMIC
WATER WELL TESTING PARAMETER LIST

Inorganic (Parameters for Potable Water)

Alkalinity	Chromium	Potassium
Aluminum	Conductivity	Selenium
Antimony	Copper	Sodium
Arsenic	Fluoride	Sulphate
Boron	Hardness	Thallium
Barium	Iron	Turbidity
Bromide	Lead	Uranium
Cadmium	Magnesium	Zinc
Calcium	Manganese	
Chloride	Nitrate/Nitrite	
Chromium	pH	

Plus: Ammonia, Total organic carbon

Microbiology
Total Coliform
E. coli Organic

Organic (Total Petroleum Hydrocarbons Water - Atlantic RBCA
Benzene
Toluene
Ethylbenzene
Xylenes
C6-C10
>C10-C16
>C16-C21
>C21-C32
Modified TPH

DRILLING AND COMPLETIONS
WATER WELL TESTING PARAMETER LIST

Inorganic (Parameters for Potable Water)

Alkalinity	Fluoride	Potassium
Aluminum	Hardness	Selenium
Antimony	Iron	Silica
Arsenic	Lead	Sodium
Barium	Lithium	Strontium
Bismuth	Magnesium	Sulphate
Boron	Manganese	Thallium
Bromide	Molybdenum	Tin
Cadmium	Nickel	Total Organic Carbon
Calcium	Nitrate	Turbidity
Chloride	Nitrite	Uranium
Chromium	Nitrate/Nitrite (as N)	Vanadium
Conductivity	pH	Zinc
Copper	Phosphorus	

Microbiology
Total Coliform
E. coli

Organic (Total Petroleum Hydrocarbons Water - Atlantic RBCA
Benzene
Toluene
Ethylbenzene
Xylenes
C6-C10
>C10-C16
>C16-C21
>C21-C32
Modified TPH

Radiological
Total Thorium
Total Radium

Gas analysis
Methane, Ethane, Propane (lab analysis)

If the ratio of gas composition (methane / (ethane + propane)) is less than 200, additional isotopic fingerprinting may be required.

APPENDIX 10: Surface Water Monitoring

Sample collection must be conducted by a qualified third-party Engineering or Geoscience firm licensed to practice in New Brunswick.

The sampling station must be identified on a site plan and described for site-specific information that may have an influence on water quality (such as land use, geology, vegetation, etc.).

Samples must be tested for the parameters indicated in the parameter lists (below).

Samples must be sent to a laboratory accredited by the Canadian Association for Laboratory Accreditation Inc. for testing.

Sampling must comply with the procedures laid out in the general sampling protocols outlined in the latest version of Canadian Council of Ministers of the Environment document Protocols Manual for Water Quality Sampling in Canada (CCME, 2011).

The third-party Engineering or Geoscience firm hired by the ONG operator will be responsible for comparing the analytical test results to the latest version of CCME's Water Quality Guidelines for Freshwater Aquatic Life where appropriate and reporting the results to Department of Environment and Local Government.

The Department of Natural Resources and Energy Development, and the Department of Environment and Local Government may require an increased number of sampling stations, increased sampling frequency, and/or additional water quality testing parameters as warranted by site-specific conditions.

Surface Water Quality Sampling and Parameter List

Water quality samples must be collected and tested prior to the commencement of land clearing and well pad construction. These samples must be collected 50 metres upstream, 50 metres downstream, and 100 metres downstream of the drilling location and must include the inorganic, organic, gas and radiological parameters listed below. Subsequent, ongoing monitoring at the same location, must be performed on a monthly basis for the parameters mentioned below (unless otherwise specified by Department of Environment and Local Government as long as drilling, hydraulic fracturing operations, or gas production continue. Sampling must continue until two months after completion of well decommissioning and site restoration unless otherwise indicated by Department of Environment and Local Government depending on site-specific circumstances (e.g. inactivity at the well site).

Field measurements of conductivity, pH, dissolved oxygen, turbidity and temperature must also be measured at the same locations as indicated above prior to the commencement of land clearing and well pad construction, and thereafter on a weekly basis, as long as drilling and hydraulic fracturing operations continue.

Parameter List

Inorganic
These parameters are equivalent to the Surface Water package at RPC. The samples must be unfiltered.

Sodium	Aluminum
Potassium	Antimony
Calcium	Arsenic
Magnesium	Barium
Alkalinity	Beryllium
Chloride	Bismuth
Fluoride	Boron
Sulfate	Cadmium
Bromine	Chromium
Ammonia	Cobalt
Nitrate+Nitrite	Copper
Nitrite	Iron
Nitrate	Lead
Nitrogen - Total	Lithium
Phosphorus - Total	Manganese
Carbon – Total Organic	Molybdenum
Colour	Nickel
Conductivity	Rubidium
pH	Selenium
Turbidity	Silver
	Strontium
	Tellurium
	Thallium
	Tin
	Uranium
	Vanadium
	Zinc

Organic (Total Hydrocarbon in Water (Atlantic MUST))
Benzene, Toluene, Ethylbenzene, Total Xylenes, C6-C10, >C10-C16, >C16-C21, >C21-C32
Modified TPH

Gas Analysis
Dissolved Methane

Radiological
Gross Alpha

APPENDIX 11: Emission Reduction Measures for Petroleum Facilities

Examples of Mitigation Measures

Examples of measures that could be taken to reduce air emissions from oil and natural gas activities include but are not limited to the following:

<u>Well Design and Drilling</u>
a) re-using drilling fluids;
b) drilling overbalanced to limit/prevent venting and/or flaring of CH4 (methane);
c) using materials with recycled content (e.g. well casing, drilling fluids);
d) using efficient rig engines;
e) using efficient air compressor engines for drilling, including alternatives to diesel compressors;
f) ensuring all flow connections are tight and sealed, and
g) performing leak detection surveys and taking corrective actions.

<u>Well Completion</u>
a) using efficient hydraulic fracturing pump engines;
b) ensuring all flow connections are tight and sealed;
c) performing leak detection surveys and taking corrective actions;
d) limiting flaring during the flowback phase by using reduced emissions completions (REC) equipment; and
e) using green completion practices *.

**Green completion practices are intended to reduce emissions of saleable gas and condensate vapours during cleanout and flowback operations prior to the well being placed on production. When a natural gas well is in the final stage of being completed, it is "cleaned up," a process that produces methane, VOCs and other emissions that are sometimes vented to the atmosphere. "Green completions" means that these gases are captured and sold rather than vented or flared. The use of green completions is generally most feasible for production/development wells (as opposed to exploration/delineation wells) since production/development wells will generally be developed in conjunction with gathering lines, allowing captured gases to be transported and sold.*

<u>Production, Processing and Transportation of Petroleum</u>

Examples of measures that could be included include implementing US EPA's Natural Gas STAR* Best Management Practices (BMP) such as:
a) reducing emissions from pneumatic devices (e.g. low or no bleed controllers);
b) reducing emissions from compressor rod packing systems by replacing worn systems that are prone to leakage;
c) reducing emissions when taking compressors off-line;
d) replacing glycol dehydrators with desiccant dehydrators;
e) replacing gas-assisted glycol pumps with electric pumps;

f) optimizing glycol circulation and installing flash tank separators in glycol dehydrators;
g) using efficient compressor engines;
h) using compressors with dry seals (wet seals use oil as a barrier to prevent gas from escaping and require venting of gas);
i) using efficient line heaters;
j) using efficient, low emission glycol dehydrators;
k) ensuring all flow connections are tight and sealed;
l) reducing emissions from storage tanks and vessels (e.g. by routing emissions to a combustion device);
m) performing leak detection surveys and taking corrective actions; and
n) using solar-powered telemetry devices.

**The US EPA's Natural Gas STAR Program is a voluntary partnership that encourages oil and natural gas companies to adopt proven, cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. Methane is the primary component of natural gas and a potent greenhouse gas.*

APPENDIX 12: Security and Emergency Planning for Oil and Natural Gas Activities

This Appendix should be read in conjunction with Appendix 4: Investigation and Response to Public Safety and Environmental Hazards Resulting from Surface Casing Vent Flow, Gas Migration and Stray Gas, and Appendix 6: Spill Prevention, Reporting and Response. These requirements may be subject to periodic revisions due to changes in identified threats, risks and vulnerabilities, as the oil and natural gas industry develops in New Brunswick and as extraction technology continues to evolve.

Emergency Management Program

In relation to threats from deliberate, accidental and natural hazards the proponent must:

1) Implement and maintain an Emergency Management Program compliant with Canadian Standards Association Standard Z1600. This requirement must remain in force for the duration of the work by the proponent, to include the Exploration, Design, Construction, Start-Up, Operations and Abandonment/De-commissioning phases of the work.

2) In relation to 1), the proponent must:
a) Submit the draft Program to the Department of Public Safety for review;
b) After review, complete amendments required by the DPS prior to approval; and
c) Submit future amendments to the Program to DPS for its information, demonstrating that the amendments remain in compliance with 1).

3) Conduct annually a threat, risk and vulnerability assessment (TRVA) specific to the proposed work, in a manner consistent with guidelines provided by the DPS, involving responsible police, fire, 911 and ambulance response agencies in the process.

4) Share the results of its annual TRVA with responsible police, fire, 911 and ambulance response agencies and with DPS;

5) Amend its Emergency Management Program annually to reflect changes in the TRVA and associated standards, and communicate amendments to local police, fire, 911 and ambulance response agencies and DPS

6) Establish and maintain linkages with responsible police, fire, 911 and ambulance, logistics support and community agencies and involve them on an ongoing basis to effectively design, develop, implement, and maintain its Emergency Management Program.

7) Report all events involving potential or actual hazards originating from any component of the proponents' operations which have potential to have impacts outside of the proponent's worksite to local police, fire, 911 and ambulance response agencies and DPS.

8) Establish and maintain participation in the New Brunswick Critical Infrastructure Protection Program through the DPS.

Security Management Program

In relation to threats from deliberate acts specifically the proponent must:

9) Implement and maintain a Security Management Program compliant with the requirements of Canadian Standards Association Standard Z246. This requirement must remain in force for the duration of the work by the proponent, to include the Exploration, Design, Construction, Start-Up, Operations and Abandonment/De-commissioning phases of the work.

10) In relation to 9), the proponent must:
a) Submit the draft Program to DPS for review;
b) After review, complete amendments required by DPS prior to approval; and
c) Submit future amendments to the Program to DPS for its information, demonstrating that the amendments remain in compliance with 9).

11) Amend its Security Management Program annually to reflect changes in the TRVA, and communicate amendments to local emergency response agencies and DPS.

12) Establish and maintain linkages with responsible police, fire, 911 and ambulance agencies and involve them on an ongoing basis to effectively design, develop, implement, and maintain its Security Management Program.

13) Establish and maintain liaison with police force of jurisdiction and the DPS in relation to security of its operations.

14) Define, within its Security Management Program, the criteria for a security event affecting or potentially affecting any component of the proponent's operations and report any such event to the police force of jurisdiction and the DPS.

15) Identify information in electronic or hardcopy form considered sensitive to the security, emergency management and business continuity of its work and take measures consistent with CSA Z246 to manage disclosure of this information to those parties necessary to conduct its work.

Training and Exercises

In relation to training and exercises the proponent must:

16) Establish, implement and maintain, as an element of its Emergency and Security Management Programs, a formal program of training and exercises for its employees and for local police, fire, 911 and ambulance response agencies along with logistics support and community agencies;

17) Pay such costs as are necessary for local emergency response agencies to develop and maintain capability to respond to and manage hazards and risks arising from the proponent's work;

18) Establish, implement and maintain a training and exercise cycle which involves both tabletop and "live" exercises;

19) Involve local emergency response, logistics support and community agencies in the conduct of training and exercises; and

20) Conduct reviews of each exercise and incorporate any findings into the review and audit cycle referenced in Items 21-23 herein.

Audit of Security and Emergency Management Programs

In relation to review and audit of its Security and Emergency Management Programs, the proponent must demonstrate initial and ongoing compliance with these directives by:

21) Identifying in its Security and Emergency Management Programs the review and audit cycle and processes to be used;

22) Conducting reviews and audits against established standards on the cycle set in its Programs using a third-party agency; and

23) Submit the findings of each review and audit to DPS, along with an action plan to remedy deficiencies and address findings.

APPENDIX 13: Highway Transportation Permits in New Brunswick

General

Planning for transportation must occur ahead of time to ensure that transporters wishing to operate in New Brunswick may proceed without undue impediments. Much progress has been made in harmonization of vehicle weights and dimensions regulations among Canadian provinces; however, a number of jurisdictions permit configurations that are not recognized in New Brunswick. Transporters must ensure well ahead of time that the vehicle configurations they wish to operate on the provincial highway system either meet the criteria or are eligible to obtain special permits that will allow for their operation under specified conditions.

Special Permits

Transporters must ensure that the vehicles they plan to operate in New Brunswick conform to New Brunswick *Regulation 2001-67, Vehicle Dimensions and Mass Regulation*, *Motor Vehicle Act*. This Regulation sets out the limits for length, width and height, as well as the limits for internal dimensions, various allowable axle group masses and total allowable gross vehicle mass. It also depicts the various vehicle configurations that can legally operate in New Brunswick without a special permit.

If the vehicle does not meet the criteria set out in the Regulation (oversize/overweight, vehicle/axle configuration does not conform, etc.), the transporter may apply for a special permit. Please note that not all vehicle configurations will be eligible to be granted a special permit.

The Department of Transportation and Infrastructure's Special Permits Office may be contacted by phone at (506) 453-2982, by fax at (506) 444-4488, or by email at special.permits@gnb.ca.

More information regarding special permits, such as the types available for purchase and the fee schedule, can be found on the Department of Transportation and Infrastructure's website under the trucking tab at: https://www2.gnb.ca/content/gnb/en/departments/dti.html

Gross Vehicle Weight Limits on Highways

Schedule B of *NB Regulation 2001-67* sets out maximum gross vehicle weight ratings for each highway category in New Brunswick. The gross vehicle weight (GVW) refers to the weight of vehicle, including its load.

New Brunswick has a 4-tiered highway classification system based on the maximum allowable gross vehicle weight rating:

43,500 kg	50,000 kg	56,500 kg	62,500kg

It should be noted that the maximum allowable gross vehicle weight rating of a vehicle configuration cannot exceed the maximum allowable gross vehicle weight rating of a highway, unless authorized by a special permit (see below). For example, a vehicle configuration rated at 62,500 kg GVW cannot legally operate at that mass on a highway rated at 43,500 kg GVW – the vehicle would be required to operate at a maximum total gross vehicle weight of 43,500 kg on that particular highway.

In addition to the list of highways described in Schedule B of *NB Regulation 2001-67,* a visual representation of New Brunswick's highway network (gross vehicle weight rating map) can be viewed on the Department of Transportation and Infrastructure website at the following location: https://www2.gnb.ca/content/gnb/en/departments/dti/trucking.html ("Maximum Gross Vehicle Weights highway map (PDF) under the "Notices and Information" section).

Special Permits for Oversize/Overmass Loads

In some instances, specialized equipment exceeds the dimensions and/or mass limits set forth in *NB Regulation 2001-67*. Special permits are required in such cases to operate legally on New Brunswick Highways. Special permits for a gross vehicle mass exceeding 72,000 kg for main highways requires a review of all structures along the route. This same process also applies to all vehicle configurations transporting loads with a gross vehicle mass less than 72,000 kg on secondary highways. A structural review can take up to three weeks to complete. The applicant should be aware that certain highways may also have height clearance restrictions due to low overhead obstacles. More information regarding the issuance of special permits, can be found under Department of Transportation and Infrastructure policy number 09-0020 – Special Permits – Oversize/Overmass Vehicle.

Temporarily Increasing the Allowable Gross Vehicle Weight on a Highway

If a transporter wishes to temporarily increase the allowable gross vehicle weight rating of a highway of a (e.g. from 43,500 kg to 62,500 kg), they may apply to the Special Permits Office. This is known as a "highway uprating". The request will be reviewed by engineering staff from the Department of Transportation and Infrastructure and may involve a structural review of all structures on the requested highway(s). Therefore, applications to "uprate" the allowable gross vehicle weight rating of a highway should be submitted at least six to eight weeks prior to the desired commencement of operations. Following the review, the applicant will be advised whether their request has been approved.

More information on the highway uprating program, including applications, can be found on the Department of Transportation and Infrastructure website, under the "Trucking" tab. Click on the "Highway Uprating Program" link under the "Special Move Permits" section of the website.

Special Permit Conditions

Special permits for oversize/overmass load and for temporary increasing the allowable GVW rating of a highway (an "uprating) are issued with terms and conditions. These are in place to protect the safety of the travelling public, as well as the Province's highway infrastructure. Examples of typical conditions of approval include limiting the hours of operation, use of escort vehicles and other warning devices, and speed restrictions. In some cases, the Department of Transportation and Infrastructure may require the permit holder to repair and/or compensate for any damage to the highway infrastructure if it has been determined that the damage has been caused by the permit holder.

Special permits may be revoked immediately upon determining that an operator did not comply with the terms and conditions under which they are issued. The Department also reserves the right to revoke a permit if the District Engineer determines that there has been excessive damage to the highway.

Conditions of movement that are issued with oversize/overmass loads can be found in Department of Transportation and Infrastructure website under the "Trucking" tab.

Compensation

Permit applicants, project proponents and/or operators are liable for any damage caused by the transport of oversize/overmass loads. Any costs resulting from such damage will be the responsibility of the permit applicant, project proponent and/or operators.

Extreme Loads

In some instances, involving more extreme sized loads, a surety or bond (damage deposit) may be required before the issuance of a permit. A Traffic Management Plan (TMP) may also be required in order to precisely describe and outline all aspects of the transport of the load, such as traffic control, detours, blocking of intersections, lane closures, opposing travel along on/off ramps, vehicle speed restrictions and/or location requirements at bridges and/or overhead obstacles, etc. In other words, the transporter must consider and provide a detailed plan describing how traffic will be safely controlled at all locations where regular traffic will be significantly impacted by the movement of such loads.

Each movement or project will be assessed on its own merits to determine if a TMP and/or a surety will be required. The general project assessment, preparation and approval process for a TMP requires advance planning. The applicant must advise the Department of Transportation and Infrastructure at least three to six months before the planned move in order to avoid delays to the transporter's schedule. A template is available from the Special Permit Office to assist the applicant in the preparation of a TMP.

Spring Weight Restrictions

Each spring, the structural strength of highways in New Brunswick is reduced by excessive ground moisture as the frost thaws. To protect the infrastructure, heavy vehicles are required to reduce their axle weights by 10% to 20% on most routes for a period of approximately 11 weeks, usually from early to mid-March until mid-to-late May. The dates can be advanced, or delayed, if there is an unexpected period of warm or cold weather. For these restrictions, the Province is divided into a southern zone and a northern zone. Restrictions are generally implemented and lifted in the south one week earlier than in the north.

<u>It is important to note that special permits for overweight loads are not issued during this time period except for emergency situations.</u>

A restriction of 80% or 90% on a highway indicates that vehicles are permitted to transport loads at axle weights that are 80% or 90% of the weights set out in *NB Regulation 2001-67*. The vehicles are also limited to the highway weight classification of the road on which they are travelling (i.e. 43,500 kg, 50,000 kg, 56,500 kg or 62,500 kg). Trucks may continue to carry the same payload if they increase the number of axles on their unit such that the axle loading is reduced to 80% or 90% of the legal limits. It should be noted however, that if at any point during the spring weight restriction period that damage to the highway becomes too severe, the District Engineer may further restrict axle loads, or may close the highway to trucks entirely.

Arterial highways (Routes 1, 2, 3, 4, 7, 8, 10, 11, 15, 16, 17, 95) and some key trucking corridors are exempt from these weight restrictions, and trucks may continue to operate on these routes at the weights set out in *NB Regulation 2001-67*. Discretionary weight tolerances that can be considered at other times of year to allow for conditions such as snow, ice and mud build up, or load shift, are not considered during the spring weight period.

The list of key trucking corridors, and other relevant information, is posted on the Department of Transportation and Infrastructure web site prior to, and during, the spring weight restriction period. This information can be viewed at the following location: https://www2.gnb.ca/content/gnb/en/departments/dti/trucking.html Click on "Spring Weight Restrictions" under the "Notices and Information" section of the website. Operators may also contact the Special Permit Office at the number noted above for information related to spring weights in New Brunswick.

APPENDIX 14: Mitigation Measures for Road Traffic Due to Oil and Natural Gas Activities

Examples of Mitigation

Mitigation measures that should be considered and employed when necessary include but are not limited to:

- Select routes to maximize public safety;
- Avoid peak traffic hours, school bus hours, community events, and overnight quiet periods;
- Coordinate with local emergency agencies, the Department of Transportation and Infrastructure and the local road authority;
- Upgrade and improve roads that will be traveled frequently;
- Provide advance public notice of any necessary detours or road/lane closures;
- Provide adequate off-road parking and delivery areas at the site to avoid lane/road blockage;
- Use alternative methods such as rail or temporary pipelines where feasible to move water to and from well sites;
- Post signs advising the travelling public of the presence of heavy vehicles;
- Select trucking routes that do not pass through municipal water well fields or watersheds that are sources for municipal water supplies;
- Provide traffic control devices or trained traffic control agents at peak times at identified problem intersections or road segments;
- Provide industry-specific training to first responders to prepare for potential accidents;
- Provide a safety and operational review of the proposed routes, which may include commitments to providing changes to geometry, signage, and signalling to mitigate safety risks or operational delays; and
- Ensure that truckloads of dirt, sand, aggregate materials, drilling cuttings, and similar materials are covered to reduce dust.

APPENDIX 15: Noise Impact Mitigation Measures for Construction and Operation of Oil and Natural Gas Wells

Examples of Mitigation

Measures that should be considered and employed when necessary to reduce noise during construction and operation of oil and natural gas wells include but are not limited to:

- Place intervening structures or materials such as tanks, trailers, topsoil stockpiles, or portable sound absorbing panels between the noise sources and receptors;
- Install temporary sound barriers of appropriate heights, based on noise modeling, around the edge of the drilling location between a noise generating source and any sensitive surroundings;
- Use noise-reduction equipment such as hospital-grade mufflers, exhaust manifolds, or other high-grade baffling;
- Limit drill pipe cleaning ("hammering") to daylight hours;
- Advise nearby residents of significant noise-causing activities and schedule these events to reduce disruption to them;
- Run casing during daylight hours;
- Place air relief lines and installing baffles or mufflers on lines;
- Limit cementing operations to daylight hours;
- Use higher or larger-diameter stacks for flare testing operations;
- Place redundant permanent ignition devices at the terminus of the flow line to minimize noise caused by flare re-ignition;
- Use rubber hammer covers on the sledges when clearing drill pipe;
- Lay down pipe during daylight hours;
- Schedule drilling and completion operations to avoid simultaneous effects of multiple rigs on common receptors;
- Limit hydraulic fracturing operations to a single well at a time; and
- Employ equipment such as electric pumps.

APPENDIX 16: Visual Impact Mitigation Measures

Examples of Mitigation

Potential visual impact mitigation measures that should be considered and employed when necessary as part of a visual impact mitigation plan include but are not limited to the following:

- Avoid placing structures at locations where they will interrupt or obscure views of crestlines or ridgelines;
- Consider how the building design (height, massing, etc.) will affect the visual impact of the site;
- Locate structures to have the least impact on views from surrounding properties. For example, avoid “skyline” locations and other locations that are highly visible;
- In grading and development, preserve salient natural features such as natural terrain, trees and groves, waterways and other similar resources;
- Keep cut and fill operations to a minimum and ensure conformity to existing topography to the extent practical;
- Paint production facilities with uniform, non-contrasting, non-reflective color tones with colors matched to the surrounding landscape;
- Direct site lighting downward and internally to the extent possible;
- Avoid “uplights” and wall-washes, as well as lighting where the bulb is visible from the fixture;
- Install lighting fixtures so they do not cast light on the neighbouring properties and public roads;
- Where security lighting is required, consider the use of lights that are activated by motion detectors;
- Reduce flare heights, consistent with technical and safety requirements; and
- Use incinerators (enclosed flares).
- Note that the safety of well site workers must be considered with respect to lighting techniques.

APPENDIX 17: Site Restoration for Oil and Natural Gas Activities

Introduction

When a site is no longer required for an oil or gas facility, it must be restored in such a manner that its capability to support different land uses is similar to its pre-construction capability. Specific requirements are provided below.

Agreement with the Landowner

These requirements are not intended to supersede site restoration requirements that may be established in an agreement between a landowner and a lease holder however any proposal by the operator of an oil or gas facility to waive or modify the reclamation requirements described below must be accompanied by documentation of the landowner's written permission.

The requirement to conduct an environmental site assessment and remediate environmental contaminants or restore environmental features such as watercourses and wetlands or to meet other legal obligations in accordance with legislation, permits or approvals, cannot be waived.

Unless stipulated otherwise in an agreement between the operator and the landowner, all costs of site restoration will be borne by the operator.

Pre-Construction Site Assessment

The landscape (drainage, contours, etc.) soils and vegetation of the site must be assessed in a systematic and objective manner, prior to the commencement of construction. This information must then be used to guide and measure the success of the subsequent site restoration. Acceptable methodologies include the recording and use of site restoration criteria for forested lands and cultivated lands, as developed by the Alberta Department of Environment and Sustainable Development.

Timing of Restoration

Within 12 months after plugging the well(s), the owner or operator must remove all production or storage facilities, supplies and equipment, including hardened structures (i.e. concrete foundations) and pipelines located on the site, and restore the site as described in these requirements.

Oil and natural gas well operators must employ progressive restoration of well pads. This means that after all planned wells on a well pad are drilled and completed, and no future re-stimulation is planned, those portions of the well pad not needed for the wellheads and their associated equipment must be restored as described in these requirements. This initial restoration must take place within 12 months of completion of the last well on the pad.

Site Restoration - General Provisions

Site restoration should be directed toward re-establishing site conditions as recorded in the preconstruction site assessment. In addition, the following general provisions apply:
a) Topsoil located within the construction footprint of oil and natural gas activities must be stripped and stockpiled for replacement during site reclamation;
b) Imported fill must be removed;
c) Cut and fill slopes must be stabilized, minimizing erosion potential;
d) For sites that were vegetated prior to the commencement of the oil or gas activity, a healthy, self-sustaining, and ecologically appropriate vegetative cover must be re-established, ensuring that invasive or non-native species are not used;
e) Agricultural fields that previously contained perennial crops must be re-vegetated with the pre-existing perennial species;
f) Other lands must be re-vegetated with similar species as found on adjacent undisturbed ground;
g) No industrial or domestic debris may remain on site;
h) No large wood debris that could be removed with a brush rake may remain on site;
i) The contour of the site must conform to adjacent land or be consistent with present or intended land uses;
j) All areas compacted by drilling and subsequent oil and natural gas operations which are no longer needed following completion of such operations must be scarified or ripped after the imported fill is removed to alleviate compaction prior to replacement of topsoil;
k) On crop land, such compaction alleviation operations must be undertaken when the soil moisture at the time of ripping is low (below 35% of field capacity). Ripping must be undertaken to a depth of 0.5 metres unless bed rock is encountered at a shallower depth;
l) Stockpiled topsoil must be redistributed to its original locations on the site;
m) If subsidence of topsoil occurs within 12 months of completion of the restoration, additional topsoil must be added to the depression and the land must be re-levelled as close to its original contour as practicable;
n) If the natural surface drainage pattern was altered by the carrying out of the oil or gas activity, the drainage pattern must be restored to its condition before the alteration. Any structure that was constructed to cross a watercourse or wetland must be removed and the site of the structure must be left in a stable condition;
o) Surface drainage and piped sub-drains (e.g. on agricultural fields), must be re-established, consistent with the original natural drainage patterns, directions, and capacity, or be compatible with the surrounding landscape and;
p) Any facilities or structures left in place must not impede natural surface drainage and water flow.

Assessment of Effectiveness of Site Restoration

Landscape, vegetation, and soil assessments must be completed to verify the effectiveness of the site restoration. Acceptable methodologies for recording the required observations include the Assessment Tools and Record of Observations Data Sheets that have been developed by the Alberta Department of Environment and Sustainable Development and are available online.

The regulator will determine a required schedule for completing the required site restoration, in consultation with the landowner and the operator.

Environmental Site Assessment

As part of the decommissioning/closure/site restoration for oil and natural gas facilities including well pads, waste management facilities, sites impacted by waste management practices, or other sites where oil and natural gas activities have taken place, an environmental site assessment including environmental sampling will be required and will be governed by the most recent version of New Brunswick's Guideline for the Management of Contaminated Sites. New Brunswick's Guideline for the Management of Contaminated Sites requires remedial action planning including waste management planning, in relation to contaminated sites.

Remediation of Contaminants

Unless otherwise determined by the Department of Environment and Local Government, clean-up of contaminated sites will be governed by the most recent version of New Brunswick's Guideline for the Management of Contaminated Sites.

APPENDIX 18: Minimum Project Notification Radius for Proposed Oil and Natural Gas Activities

These minimum notification distances refer to direct notification of those who are located in proximity to proposed oil or gas activities that must be registered for review under the *Environmental Impact Assessment Regulation, Clean Environment Act.* These distances refer to direct, written notification of tenants and landowners located in proximity to a proposed oil or gas project and may be adjusted by the regulator according to site specific conditions.

Other public notification activities such as open houses, newspaper notices notification of elected officials, etc. are typically required in accordance with project-specific criteria established in consultation with the regulator. Additional information pertaining to public notification and involvement during a determination review under the above regulation is contained in *A Guide to Environmental Impact Assessment in New Brunswick* (January 2018).

Notification Distances

The following notification distances are measured horizontally from:
a) The centre point of a facility (e.g. well pad, compressor station, gas processing facility, etc.); and
b) The centre of the right-of-way of a proposed pipeline or access road.

Facility	Minimum Notification Distance
Processing plant, compressor station or pumping station	3,000 metres
Well Pad	1,800 metres
Pipeline	200 metres
New Access Road	200 metres

Notification of Local Governments

A proponent must directly notify a local government if: a) buildings or structures owned by a local government; b) an area contained in a local plan; or c) lands that fall within the boundaries of the local government's jurisdiction fall within the above notification distances.

APPENDIX 19: Fracture Fluid Disclosure and Risk Assessment

Introduction

It is the intent of these requirements that: a) the substances injected into a well bore for the purposes of hydraulic fracturing are known to the regulator; b) an assessment of the risks to human health and the environment of all ingredients in a facture fluid system is completed as described below and submitted to the regulator for review; and c) the information described in a) and b) is made available to the public, as permitted by applicable legislation and in accordance with and subject to the specific provisions described below.

Definitions

When used in this document:

"additive" means the individual additive that performs a certain function within the fluid system. Typically, several additives are combined in the fluid system.

"base fluid" means the fluid that comprises the main component of the fracture fluid system (typically water).

"fracture fluid system" means the fluid delivered down-hole that consists of one or more additives plus the base fluid and proppant.

"hydraulic fracturing program" means a program comprised of one or more fracturing stages within the same well bore.

"ingredient" means the individual chemical constituents of an additive.

"risk assessment" means an assessment that: a) considers the physical, chemical and toxicological properties of the ingredients of a fracture fluid system; b) categorizes the additives (based on their ingredients) in terms of their potential health and environmental impacts; c) identifies those additives for which special controls or practices are required in order to reduce risk to human health and the environment; and d) identifies the measures proposed in c).

Operations that are Subject to Disclosure

These disclosure requirements apply on a well-by-well basis to each oil or gas well where hydraulic fracturing takes place regardless of the date that the well was initially constructed.

A service company that performs hydraulic fracturing treatment on a well or a supplier of an additive used in a hydraulic fracturing treatment must either comply with these requirements or provide the owner or operator of the well with the information necessary to comply.

Timing of Disclosure

<u>Initial Disclosure</u>

At the time that hydraulic fracturing is proposed under the phased environmental impact assessment (EIA) review process under the *EIA Regulation, Clean Environment Act,* the proponent must submit as many of the items listed under Hydraulic Fracture Fluid Information Requirements (below) as available.

At least 30 days prior to commencing a hydraulic fracturing program, the well permit holder must supply the Department of Environment and Local Government with the anticipated details of each of the items listed under Hydraulic Fracture Fluid Information Requirements and the results of the Risk Assessment (below). Other chemicals to be used in the well bore in addition to those used in a hydraulic fracturing fluid (e.g. concrete additives, drill muds, etc.) must also be described.

<u>Post-Fracturing Verification</u>

Within 30 days of the completion or suspension of a hydraulic fracturing program, the well permit holder must supply the Department of Environment and Local Government with the actual details of each of the items listed under the Hydraulic Fracture Fluid Information Requirements and Risk Assessment (below) if different from the previously supplied information.

<u>Blanket Submissions</u>

When multiple fracturing stages are proposed at a given well or group of wells, the required information can be supplied in a single submission within each time period described above, covering the whole of the hydraulic fracturing program at the well(s).

Hydraulic Fracture Fluid Information Requirements

Information requirements include the following:
a) the well permit number, well operator name, well location (latitude and longitude) and well depth (true vertical depth);
b) the type of base fluid and the total volume of hydraulic fracture fluid to be employed during the hydraulic fracturing program;
c) all additives including their trade names, suppliers and their purpose including but not limited to biocide, breaker, brine, corrosion inhibitor, cross-linker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, surfactant, etc.;
d) the chemical ingredient name and the Chemical Abstracts Service (CAS) registry number * of each ingredient;
e) the maximum concentration of each chemical within each additive and of each additive within the fracture fluid (expressed as a percent);

f) a summary of any changes to the constituents or concentrations of the additives from those identified in any previous submissions;
g) current Materials Safety Data Sheets for the substances listed under “d” when such sheets have been prepared; and
h) a statement indicating whether or not:

(i) any chemical ingredients were used for which an MSDS is not available;
(ii) an exemption from disclosure of a chemical name and/or concentration (d) and e) above) has been received in accordance with Canadian Federal legislation (i.e. Section 11 of the *Hazardous Materials Information Review Act***); or
(iii) an exception from public disclosure of a chemical name and/or concentration under (d) and (e) above is claimed pursuant to the *Right to Information and Protection of Privacy Act.*

Should an exemption under ii or iii above be granted, the information described under items d) and e) (along with all other information required above) must still be submitted to the Department of Environment and Local Government, however this information will be kept confidential by the Department except where, in the opinion of the Minister of Environment and Climate Change and/or the Minister of Health, disclosure to a third-party professional (first responder, medical professional, site remediation specialist) is necessary for the purposes of protecting public health, public safety or the environment in accordance with Section 22 (5) of the *Right to Information and Protection of Privacy Act.*

**A CAS registry number is a numerical identifier that serves as a naming convention for chemicals. It provides a way to uniquely identify a chemical substance that may be known by several names.*

***Within Canada, any supplier who is required to disclose the chemical identity or concentration of any ingredient of a controlled product pursuant to the provisions of the* Hazardous Products Act, *may, if the supplier considers such information to be confidential business information, claim an exemption from the requirement to disclose that information by filing a claim for exemption under the federal* Hazardous Material Information Review Act *(HMIRA).*

Risk Assessment

The well permit holder must provide the results of an assessment of the potential health and environmental risks of each additive to be employed and the operational controls and practices that will be used to manage the risks that are identified. This can be accomplished using a methodology such as the computer-based risk assessment tool developed for the Canadian Association of Petroleum Producers.

Reporting the Flow-Back Volume

Within 120 days of the completion of the hydraulic fracturing program, the well permit holder must supply to the Department of Environment and Local Government an estimate of the volume of injected fluid that returned to the surface and an estimate of the volume that remained in the formation, as of 90 days after completion of the hydraulic fracturing program.

Timing and Method of Public Disclosure

Within 30 days of the completion of the hydraulic fracturing program, the well permit holder must make the post-hydraulic fracturing report available on a third-party, publicly accessible internet website such as www.FracFocus.ca*, and must also make this information available to the public by hard copy on request. Information exempted from public disclosure under the *Right to Information and Protection of Privacy Act* is not required to be disclosed by the well permit holder, but the presence of these ingredients must be noted as "chemical ingredient name omitted" in the list of ingredients and their functions".

**A hydraulic fracturing chemical registry website (www.fracfocus.org) was launched in April of 2011 as a joint project of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. On this site the public can search for information about the chemicals used in the hydraulic fracturing of specific oil and natural gas wells throughout the US. A Canadian version of this website (www.fracfocus.ca) was launched by the government of British Columbia in January of 2012.*

DEFINITIONS
When used in this document:

“annulus” (annular space) means the ring-shaped space (gap) between the outside of a well casing and the wall of the well bore or between two layers of overlapping casing.

“battery” means a system or arrangement of tanks or other surface equipment receiving the production of one or more oil or gas wells prior to its transportation, and includes the separators, dehydrators, storage tanks, pumps, compressors and other surface equipment by which fluids (e.g. oil, natural gas, produced water) coming from a well are separated, measured or stored.

“blow-out” means an uncontrolled flow of reservoir fluids (i.e. water, oil or gas) into a well bore, whether or not the flow reaches the surface.

“casing bowl” means the part of the well head (the top of a well) that incorporates features to secure and seal the upper end of the casing string and provides the foundation for the wellhead.

“casing seat” means the location of the bottom of a segment (string) of casing that is cemented in a well.

“casing shoe” means a metal collar attached to the bottom of a segment (string) of well casing.

“casing string” means a complete segment of well casing (surface casing, intermediate casing, or production casing) assembled from a number of pipe sections that are typically joined together using threaded couplings.

“casing vent” means a connection between the atmosphere and an annulus.

“cement evaluation log” means a method of verifying the integrity of cement that has been installed in an oil or gas well. One example is a “cement bond log”, in which information obtained from acoustic signals passing along the well casing, is used to evaluate cement-to-pipe and cement-to-formation bonding.

“cement top” (top of cement) means the highest elevation of cement in an annulus.

“cement top log” means a way of determining the highest elevation of cement in an annulus.

“centralizer” means an object placed in the well bore to position (centre) the casing strings within the well bore to help ensure that cement surrounds the well casing. Centralizers are made with two bands that fit the pipe tightly with spring steel ribs that arch out to press against the wall of the well bore.

“Christmas tree” means an assembly of valves and fittings at the top of an oil or gas well, used to control well flow.

“circulation method” means pumping a volume of fresh water into the well casing (after a sufficient volume of cement to fill the annulus is pumped into the casing) until the casing cement reaches a specified elevation in the annular space.

"closed-loop drilling fluid system” (sometimes referred to as a "closed mud" or a "pitless" system) means a system for managing drilling fluid (drill mud) that eliminates the need for excavated pits. Pits are replaced by a series of storage tanks that separate liquids and solids and facilitate recycling of the drilling fluid.

“completion” means preparing a well for production, which involves removing the drilling equipment, stimulating the well (i.e. hydraulic fracturing) and installing valving, and other flow-control devices.

“conditioning” means cleaning and preparing a well bore prior to cementing.

“conductor casing” means a casing installed and cemented in a well to perform the same function as a conductor pipe and also to facilitate well control during drilling of the hole that will contain the surface casing.

“conductor pipe” means a vertical pipe installed in a well to prevent the ground near the surface of the well bore from caving in and to conduct drilling mud (fluid) from the bottom of the well bore to the surface when drilling starts. It includes a seal to prevent infiltration of groundwater into the well bore but is not used for well control.

“designated public water supply” means wellfields or watersheds that have been designated under the provisions of the Watershed Protected Area Designation Order or the Wellfield Protected Area Designation Order under the *Clean Water Act.*

“diminished in quality" means a reduction in water quality based on the chemical, physical and bacteriological parameters that could potentially be affected by seismic testing or by the drilling, completion, operation and decommissioning of an oil or gas exploration or production well, as evidenced by: a) a comparison between pre- and post-activity water well sampling and; b) a comparison of the water well test results with the normal range of variation in water quality for the aquifer under consideration (with reference to information sources such as the Department of Environment and Local Government’s water quality database and the New Brunswick Groundwater Geochemistry Atlas); and c) a review of the substances stored at, used at or produced at the location of the seismic testing or well pad, including substances used in the wellbore or found in geological formations that are penetrated by the well bore or by the induced fractures.

“diverter” means a system used to direct fluid (e.g. oil, gas, formation water) away from the drilling rig (e.g. when a “kick” is encountered).

"drill cuttings" means chips and small fragments of rock that are brought to the surface during the drilling of an oil or gas well. They are carried to the surface by the drilling fluid.

"drilling fluid" (drilling mud) means a fluid that is pumped down the well bore to cool and lubricate the drill bit. After reaching the bit, the drill fluid typically circulates back up the well bore to the surface.

"drilling out" means drilling through concrete plugs in a casing string.

"drill rig" means the equipment used to drill a stratigraphic test well or an oil or gas well.

"dwelling" means any permanently or seasonally occupied residence located and constructed in accordance with all applicable legislation, building codes, and by-laws. It does not include an employee residence, dormitory, or construction camp associated with an oil or gas activity.

"exploration/delineation well" means a well that is drilled in or near an area with known or suspected oil of gas potential, in order to further evaluate this potential. This well may become a production/development well and may be subject to hydraulic fracturing.

"flood prone areas" means a mapped 1:100-year floodplain, or any other area prone to flooding that may be identified by the regulator based on evidence such as coastal hazard mapping, historical records, etc.

"flowback water" means water emitted by a well from the time of initial drilling, until the well is abandoned or goes into production. For wells that have been stimulated using hydraulic fracturing, flowback water is typically a mixture of fracture fluid and formation water.

"formation integrity test" means a pressure test to determine if the geological formation and the casing shoe can withstand the maximum anticipated pressure during the drilling of the next section of the bore hole.

"formation leak-off test" means a pressure test to determine the strength of the geological formation in order to establish a maximum allowable pressure that can be employed during drilling without allowing the drill fluid to leak into the surrounding formation.

"formation water" means naturally occurring water found within geological formations. When it comes to the surface along with oil and natural gas it is called produced water.

"fracture half-length means the radial distance initiated from the subject well bore to the outer tip of a fracture propagated by fracturing.

"gas migration" (GM) means a flow of gas that is detectable at surface outside of the outermost casing string (often referred to as external migration or seepage). A GM is serious if there is a fire

or public safety hazard or off-lease environmental damage, such as groundwater contamination. A GM is non-serious if it has not been classified as serious migration.

“gathering line” means a pipeline used to transport crude oil or gas from individual wells to a conditioning plant or a main pipeline.

"high volume hydraulic fracturing" means a well completion operation in which the volume of injected base fluid exceeds 1000 cubic metres in any single stage of a hydraulic fracturing program.

“hydraulic fracturing” (sometimes referred to as “fracking” or “fracing”) means injecting a liquid or gaseous fluid (e.g. water, nitrogen, polymer, or a petroleum-based fluid such as propane) at high enough pressures to fracture or crack the rock in the target zone. Hydraulic fracturing is a method of stimulating production from a formation of low permeability, by applying very high fluid pressure to the face of the formation, forcing the strata apart.

“hydraulic fracturing program” means a program comprised of one or more fracturing stages on the same well bore.

“image log” means the results of a procedure (e.g. resistivity, acoustic imaging, etc.) that provides an image of the wall of a well bore.

“individual water supply” See “private individual water supply”.

“intermediate casing” means steel well casing placed inside the surface casing and outside the production casing that is used for well control or to protect non-saline groundwater.

“Kelly valve” means a valve to protect well equipment from high pressure.

“kick” means an entry of water, gas, or oil into the well bore from the surrounding geological formation during drilling. It occurs when the pressure exerted by the weight of drilling fluid in the well bore is less than pressure exerted by the fluids in the formation being drilled.

“licence to search” means a licence issued in accordance with the Licence to Search and Lease Regulation - Oil and Natural Gas Act *that allows the licence holder to explore for oil and natural gas.*

“liner” means a casing string that does not extend to the top of the well bore, but instead is anchored or suspended from the bottom of another casing string.

“Non-designated public water supply” means wellfields or watersheds that have been delineated but not yet designated under the provisions of the Watershed Protected Area Designation Order *or the* Wellfield Protected Area Designation Order under the Clean Water Act.

"non-saline groundwater" means groundwater having a concentration of total dissolved solids of less than 15,000 mg/L (i.e. 15,000 ppm). It includes shallow, potable groundwater that takes part in the hydrologic cycle and typically excludes water from deeper formations that are isolated from the surface.

"oil and natural gas activity" means:
a) geophysical exploration including the drilling of a stratigraphic test well or bore hole;
b) drilling and completion (e.g. hydraulic fracturing) of an oil or gas well;
c) production, gathering, and processing of oil, natural gas or both, up-stream of a refinery; and
d) abandonment and site remediation.

"oil and natural gas facility" means a facility used as part of an oil and natural gas activity including: an oil or gas well, a well pad and all related equipment used for oil or gas exploration or production, a battery, a gathering line, a storage tank, a freshwater impoundment, a gas conditioning plant or a compressor station.

"oil or gas well'' means a well, constructed to intersect with oil and/or gas-bearing strata in order to explore for or produce oil or natural gas. This includes an "exploration/delineation well" and a "production/development well" but does not include a "stratigraphic test well".

"operator" means the holder of a licence, permit, certificate of determination or approval issued by the regulator, to engage in an oil and natural gas activity or construct or operate an oil and natural gas facility.

"packer" means an expandable device used to seal a well bore or annulus.

"pass-by flow" means a quantity of flow in a river or stream that must be allowed to pass by a water intake (i.e. remain in the river or stream) during the time that a withdrawal is occurring.

"polished bore receptacle" means a section of well casing that is designed to facilitate the connection of the well casing to a tie-back string.

"production/development well" means a well that is drilled within a known, producing oil or gas field in order to produce oil or gas. This well may be subject to hydraulic fracturing.

"private community water supply" means a water supply serving more than one user (for example a campground, or mini home park, a residential subdivision).

"private individual water supply" means a water supply serving an individual user (for example, serving a single dwelling).

"private industrial, commercial or agricultural water supply" means a water supply that is used for industrial, commercial, or agricultural purposes (for example a mill, factory, farm, aquaculture facility, business, etc.) and who's use may be for potable or non-potable purposes.

"private water supply" See "private communal water supply", "private industrial, commercial or agricultural water supply" and "private individual water supply".

"produced water" means water found in a subsurface geological formation that comes to the surface along with oil and natural gas during hydrocarbon production.

"production casing" means the portion of the steel well casing that extends through the oil or natural gas- bearing geological formations.

"production liner" means a casing string used for oil or gas production, which does not extend to the top of the well bore, but instead is anchored or suspended from inside the bottom of the previous casing string.

"proppant" means a material contained in hydraulic fracturing fluid that "props open" the fractures that are created as a result of hydraulic fracturing, to allow gas or oil to flow to the well bore.

"porous zone" means a zone that; a) has carbonates with effective porosity greater than 1 per cent or; b) has sandstones with effective porosity greater than 3 per cent; or c) has offset production, regardless of the porosity; or d) has drill stem test formation fluid recoveries greater than 300 linear metres or gas volumes greater than 300 cubic metres.

"public and Crown water supply" means a water supply that is owned or operated by a municipality or the Crown in right of the province and is not a "designated public water supply" or a "non-designated public water supply" (for example nursing homes, hospitals, schools, parks, etc.).

"public water supply" See "designated public water supply", "non-designated public water supply", and "public and crown water supply".

"pump and plug method" means a technique for placing cement plugs at appropriate intervals along the well bore.

"proponent" means one who proposes to engage in an oil and natural gas activity or construct or operate an oil and natural gas facility but has not yet received a licence, permit certificate of determination or approval from the regulator to do so.

"provincially significant wetland" means a wetland with provincial, national, or international importance and shown on the GEONB provincially significant wetland layer.

"qualified professional" means a person who has sufficient knowledge and experience to carry out the required function.

“qualified Professional Engineer or Geoscientist” means a Professional Engineer or Geoscientist licensed to practice in New Brunswick by the Association of Professional Engineers and Geoscientists of New Brunswick.

“regulated wetland” means a wetland that is shown on the GeoNB regulated wetlands layer or on the GeoNB provincially significant wetlands layer. For regulation implementation purposes, the Department of Environment and Local Government currently regulates wetlands that are shown on these layers.

“regulator” means the government department or agency having jurisdiction.

“secondary containment” means one or more of the following: dikes, berms, curbs, sumps, or other structures or equipment capable of containing leaks and spills from a tank, container, vessel or area. The secondary containment must: a) be sufficiently impervious and able to contain spilled material until it can be removed or treated; and b) be compatible with the waste material or waste stored or used within the containment. The secondary containment may surround an entire site (e.g. a well pad or a liquid storage and handling area), or one or more tanks, containers, or vessels. The secondary containment must be of sufficient volume to contain 110% of the capacity of the largest single tank or of all the connected tanks (whichever is greater).

“seismic source point” means a location where kinetic energy is applied to the ground (e.g. a shot hole or vibroseis plate).

“shallow hydraulic fracturing” means hydraulic fracturing taking place where the target zone is less than 600 metres below the surface (true vertical depth) or at any other depth that may be defined by the regulator based on site-specific geology.

“shot hole” means a drilled hole, into which an explosive energy source (charge) is placed as part of a seismic testing program.

“sour gas” means natural gas that contains concentrations of hydrogen sulphide that would represent a risk to human health, should the natural gas escape.

“stabbing valve” means a valve at the top of a drill hole that can be closed to stop unexpected well flow.

“stray gas” means gaseous material that migrates from an oil or gas well or facility to a location where it may create a hazard.

“stratigraphic bore hole”, or “stratigraphic test well” means a well that is drilled in order to identify and evaluate the subsurface geology of an area. It is not used for oil and natural gas production and does not involve hydraulic fracturing.

“surface hole” means the hole that is drilled to allow installation of the surface casing.

“surface casing” means the steel casing that is inside the conductor casing or conductor pipe. It is a permanent structure of the well bore and extends from the ground surface to a specified depth. The primary purpose of surface casing is to protect non-saline groundwater.

“surface casing vent flow” (SCVF) means the flow of gas and/or liquid or any combination out of the annulus between the surface casing and the second (next inner) casing.

“tie-back string” (tie-back tubing) means a section of tubing that is run from a polished bore receptacle to the surface (wellhead). A tie-back string is not cemented in place and can be used to provide the necessary well pressure during hydraulic fracturing.

“tour sheets” (tour reports) means drilling-related data collected by an automated electronic recoding system connected to a drill rig.

“tripping” means pulling the drill string out of the hole or replacing it in the hole (e.g. because the drill bit has dulled or has otherwise ceased to drill efficiently and must be replaced).
“tubing” means a small diameter pipe placed inside a well casing to conduct fracture fluid or oil and natural gas and help control the well.

“true vertical depth” means the vertical distance from a point in the well bore to the surface, irrespective of the length of the well bore. (The length of the well bore is referred to as the measured depth).

“unconventional oil or gas” means oil or gas found in very fine-grained sedimentary rock (e.g. shale or sandstone) and tightly locked in very small spaces, that requires special technologies, including hydraulic fracturing and directional drilling to drill and extract.

"unconventional formation" means a geological formation containing unconventional oil or gas. In New Brunswick these include the Hiram Group Sands and the Frederick Brook Shale.

“vacuum truck” means truck equipped with a heavy-duty vacuum and a collection tank that is used to pick up, contain and transport liquids.

“vibroseis” means a method of seismic testing that employs a truck-mounted vibrating plate that is placed in contact with the ground.

“watercourse” means a watercourse as defined in the Clean Water Act*. In interpreting this definition, the Department of Environment and Local Government considers a watercourse to be any incised channel or body of standing water, open to the atmosphere, with a bed containing exposed mineral or organic soil substrate; whether the flow or presence of water is permanent, intermittent or ephemeral. The definition includes the full width and length of the channel or water body, including bed, banks and sides. It includes portions of roadside and rail side ditches*

that intercept and convey stream flow from off the right-of way. It excludes all other portions of roadside and rail side ditches and constructed agricultural ditches.

"water supply" means a water well or surface water source used for potable, industrial, agricultural, or commercial purposes.

"well bore" means the drilled portion of an oil or gas well.

"well head" means the part of a completed oil or gas well located at the ground surface. It typically includes an arrangement of valves and piping for pressure control.

"well licence' means a licence to construct an oil or gas well, issued in accordance with the Oil and Natural Gas Act.

"well pad" means the area occupied by an oil or gas well and related equipment including the well head, and the battery.

"wetland" means a wetland as defined in the Clean Water Act. *In interpreting this definition, the Department of Environment and Local Government currently regulates wetlands that are shown on the GeoNB regulated wetlands layer and wetlands that are shown on the GeoNB provincially significant wetlands layer.*

"zone of critical cement" means: (i) for surface casing strings greater than 90 metres in length, the bottom 20% of the casing string, (ii) for surface casing strings of 90 metres or less in length, the zone of critical cement extends to the surface; and (ii) other zones as may be determined by the regulator.*

**Provided that the zone is not more than 300 metres long or less than 90 metres long.*