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Acknowledgement

The consultants would like to acknowledge the substantive contributions to this study and report of the members of Nova Scotia’s Hydraulic Fracturing Review Committee, comprised of representatives from Nova Scotia Environment and Nova Scotia Department of Energy. The scope of this study covered a large number of jurisdictions and addressed issues and questions that encompassed a wide range of specialized skills and interests. It would not have been possible to complete without the full commitment and cooperation of the members of this committee. While we may have been the facilitators and compilers, this report must be seen as a joint effort, and we thank them all for their inputs and efforts.
Introduction

Paul Precht of Paul Precht Energy Economics Ltd and Don Dempster of Wolf Island Engineering (the consultants) were engaged to assist Nova Scotia’s Hydraulic Fracturing Review Committee, which is co-chaired by the Nova Scotia Department of Energy and Nova Scotia Environment, in its review of regulatory approaches to hydraulic fracturing in selected jurisdictions in North America. The goal of this jurisdictional review is to:

a) assist Nova Scotia in learning how other jurisdictions regulate unconventional resource development in particular with regard to hydraulic fracturing and;

b) identify current regulatory best practices for activities related to hydraulic fracturing.

This report will describe the process for conducting the review, and then will present a highly detailed summary of information respecting the various jurisdictions included in the review. The summary information is presented in tabular form, and the tables follow, generally, the structure of the questionnaire used to interview the respective jurisdictions. The nine jurisdictions reviewed are arranged in groups of three, and there are nine tables for each group of jurisdictions. Following the tables is a series of attachments which identifies key legislation, regulations, and guidelines relating to hydraulic fracturing for each jurisdiction. The final attachment to the report is a copy of the questionnaire.

It should be noted that this report is the result of a joint effort between the Hydraulic Fracturing Review Committee and the consultants.

Review Process

Questionnaire

The Hydraulic Fracturing Review Committee developed a series of questions, in consultation with the consultants, designed to elicit information regarding how unconventional resource development and hydraulic fracturing activities are regulated. This information will be used to inform the Committee on:

- current legislation and regulations regarding the activities associated with hydraulic fracturing in both established and emerging jurisdictions, and
- current regulatory best practices employed by the selected jurisdictions, related to hydraulic fracturing.

The questionnaire was used to guide the interviews, and to ensure the desired information was obtained from these jurisdictions. Before sending the questionnaires, representatives of the Committee and the consultants sought to complete the questions, to the extent possible, based on information publicly available.

Primary sources such as law and regulations, often supplemented by guidelines, bulletins and directives were the preferred sources. However, at times it was necessary to reference secondary sources, such as studies and publications by third parties.

The questionnaire included sections on:
• Overview of Regulatory Process,
• Drilling and Completion Operations,
• Landowner/Public Concerns,
• Environmental Issues,
• Financial Security, and
• Data Collection and Dissemination.

A copy of the Questionnaire is included in this report as Attachment 2.

Jurisdictions
The jurisdictions to be interviewed were selected by the Committee, in consultation with the consultants, and consisted of the following nine jurisdictions:

- Alberta,
- British Columbia,
- New Brunswick,
- Saskatchewan,
- New York,
- Ohio,
- Pennsylvania,
- Texas, and
- Wyoming.

These jurisdictions were chosen because they are oil and gas producers who have, or are expecting to have, hydraulic fracturing taking place within their jurisdictions. The goal was also to select jurisdictions that were at different stages of industry development and regulatory maturity. They included jurisdictions such as Texas and Alberta, who have mature regulatory structure and jurisdictions such as New York and New Brunswick who have emerging shale gas production. All jurisdictions indicated they are in various phases of transition and development related to the level of unconventional resource development and the use and regulation of hydraulic fracturing.

Interviews
Following initial completion of the questionnaires by the Committee and consultants, the appropriate technical regulatory officials were contacted in the selected jurisdictions to set up the teleconference interviews. Each jurisdiction was sent a copy of the questionnaire for review prior to the conference call. The calls were typically 2 hours in length, and included technical experts from the jurisdiction, the consultants as well as members of the Nova Scotia Committee. A number of jurisdictions were interviewed several times, in particular those which had more than one regulatory authority responsible for aspects of oil and gas development.

The interviews followed the questionnaire, with the technical experts from respective jurisdictions offering corrections, additions and elaborations on the questions and answers. Nova Scotia Committee
members and the consultants posed follow-up questions in their areas of interest and responsibility in response to the information provided by the jurisdictions.

Of the nine jurisdictions included in the review, six were able to fully participate – Alberta, British Columbia, New Brunswick, Saskatchewan, New York and Wyoming. Although questionnaires were sent to Ohio, Pennsylvania and Texas, they were unavailable for teleconference interviews. Texas regulators did return an annotated version of the questionnaire which included some revision and additional information. Pennsylvania directed the consultants and Committee to the STRONGER report (2010) for information on Pennsylvania’s regulatory approach to hydraulic fracturing. Information for Ohio was generated by the Committee and the consultants.

Following each teleconference, a revised and updated version of the completed questionnaire was prepared for that jurisdiction. The information obtained from these questionnaires and interviews is summarized in the 27 tables commencing on page 10.

**Results**

This report is designed to capture the information obtained from the questionnaires and the discussions in the teleconference interviews by summarizing it in a tabular format. To accommodate readability, the jurisdictions were placed in groups of three for the purposes of organizing and presenting the information in tabular form. The following section provides some observations and comments regarding this information.

**Key Issues**

All the jurisdictions reviewed have existing or potential shale gas resources. They are all aware of the recent controversy regarding shale gas production throughout North America and are dealing with it in a variety of ways including formal regulatory reviews in about half the jurisdictions, and reviews of at least some aspects of the regulatory framework in most of the other jurisdictions.

The central focus of regulatory reviews is the use of hydraulic fracturing in the development of unconventional resources. Public concerns primarily revolve around water. Hydraulic fracturing can require a significant volume of water, often 20 million litres or more per well. Every jurisdiction that responded indicated that potential impact of hydraulic fracturing on water quality in nearby water wells was an issue with the public, and mostly in regards to groundwater protection. Some of the jurisdictions were also concerned about water shortages. Therefore, ensuring the protection of water quality and the sources of water has become an important focus of much of hydraulic fracturing regulations.

Some key issues relating to regulating hydraulic fracturing are briefly discussed below.

**Well Casing & Cementing**

Generally, the jurisdictions viewed proper design and construction of the well as the first line of defence in protecting ground water. To achieve this, the regulators relied variously on casing programs, cementing programs and well integrity testing in their regulations. For example:

- All the jurisdictions required surface casing as part of their casing program,
- All also had specific requirements for subsequent casing strings in the well,
Six of the nine had regulations which explicitly set cement quality standards while others were less explicit as to how the quality of cement was selected and ensured, and while cement bond logs were not often required as a regulatory requirement, all but two of the regimes studied required pressure testing and/or cement bond logging in order to establish cement integrity in the wells in cases where there were no cement returns to the surface.

The jurisdictions interviewed stressed the importance of proper well design and construction. As state officials in Wyoming put it, “Regardless of whether the well is conventional or unconventional, well design and construction is paramount”.

**Protecting Water Wells and Groundwater**

- Six of the nine jurisdictions (plus Alberta for Coal Bed Methane) required base-line testing of water quality before (and sometimes after) drilling could commence,
- Five of nine explicitly required minimum distances between other wells and the proposed well to avoid possible contamination, and
- Five of nine required vertical separation of the petroleum well casing string and the lowest aquifer zone in order to protect that aquifer.

**Water Allocations**

Access to water is a big issue in some jurisdictions, especially those where water is in short supply. Wyoming, for example, is chronically short of water. Water access may also be an issue in Southern Alberta and Southern Saskatchewan, especially in times of drought or seasonal shortages.

Recycling does not appear to be a regulatory requirement yet, but is generally encouraged. In many jurisdictions, the petroleum industry, in times of shortage, is the first sector to be denied water, over the more permanent users such as agricultural and municipalities.

It was suggested by one jurisdiction that if they had to access salt water, they would consider using that for hydraulic fracturing purposes in their jurisdiction.

- Five of the nine jurisdictions required some form of licencing for water withdrawals without being subject to volume thresholds,
- Three of the nine required some form of licencing of water withdrawals over a certain volume threshold, and
- New Brunswick currently deals with with water acquisition via its Environmental Impact Statement.

**Public Disclosure of Injection Additives**

All the jurisdictions reviewed and interviewed stressed the importance of disclosure of the chemical additives in the fracturing operations. Three of the jurisdictions have made it mandatory to disclose the additives publically. One has made the public disclosure voluntary and is one of the five requiring disclosure to the regulatory authorities within their jurisdiction. One is still considering mandatory disclosure and plans on implementing the requirement shortly.

Here in Canada, BC has initiated a Fracfocus website that is similar to the existing US website and is requiring that its industry publically document the additives they use in hydraulic fracturing within the
province. As of January 1, 2012, disclosure on www.Fracfocus.ca is required by the BCOGC. Companies are beginning to publish their hydraulic fracturing fluid composition on this website. The ERCB in Alberta has recently announced that it is following BC’s initiative.

**Fluid Handling and Management**
The handling, storage and disposal of fluids associated with hydraulic fracturing operations, such as flowback fluids and production waters, is also very important to the jurisdictions interviewed. This is in order to ensure these flowback waters are not a source of contamination.

- While most of the jurisdictions allowed earthen pits to be used, four required liners to be in place and one restricted the type of fluid to be allowed.
- Six of the nine required deep well disposal or injection of fracturing fluids with permitting conditions while two of the nine did not allow deep well injection for geological reasons.
- All encouraged recycling of the fracturing fluids, but only one jurisdiction, BC, indicated that it was occurring in the province.

**Older Wells and Well Communication**
BC, Alberta and Saskatchewan all noted the risks associated with existing, near-by petroleum wells being affected by the new well being fractured. Documented evidence of hydraulic fracturing operations having caused inter-well communication does exist.

The integrity of older abandoned wells in proximity to wells undergoing hydraulic fracturing is also important and potentially problematic. Some older wells were drilled and completed to lesser standards than exist today, and the downhole tubulars may not meet today’s standards. They may also have degraded and corroded, and there is no way to ascertain that status. Therefore, older wells which have been poorly or improperly decommissioned (plugged and abandoned) may also pose a risk if located in proximity to hydraulic fracturing operations, and especially if penetrating the same formation as being fractured.

**Public Concerns**
All interviewed acknowledged that public concerns have been expressed regarding hydraulic fracturing in their jurisdictions. Steps are being taken to address these concerns, and often additional financial and human resources have been assigned. Regulatory reviews and changes are being framed to include and address issues raised by the public. A number of jurisdictions have made extensive public information efforts and community outreach, such as, community meetings and workshops, and development of public information materials.
## Tables for Alberta, British Columbia and Wyoming

### Table A-1: Overview of Regulatory Processes and Regulatory Challenges

<table>
<thead>
<tr>
<th>Bodies responsible for regulating unconventional resource development. Do they differ from conventional gas?</th>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>• The Energy Resources Conservation Board (ERCB) regulates all oil and gas activities.</td>
<td>• The Oil and Gas Commission (OGC) is the main regulator of oil and gas activities including regulation of specified provisions the <em>Environmental Management Act</em>, <em>Forest Act</em>, <em>Heritage Conservation Act</em>, <em>Land Act</em> and <em>Water Act</em> as provided for under the “specified enactments” as they relate to oil and gas activities. A “single window” approach to regulating the petroleum industry in BC.</td>
<td>• The Wyoming Oil and Gas Conservation Commission (WOGCC) has primary responsibility for regulating oil and gas operations in the State.</td>
<td></td>
</tr>
<tr>
<td>• Alberta Environment and Water (AE&amp;W) regulates water resource usage for all oil and gas activities.</td>
<td>• The OGC can authorize short-term (i.e., ≤12 months) surface and subsurface water use for oil and gas activities, whereas the Ministry of Forests, Lands and Natural Resource Operations is responsible for long-term water surface water licenses.</td>
<td>• The Department of Environmental Quality (DEQ) regulates air, water and land quality, including Class I and V injection wells (EPA program).</td>
<td></td>
</tr>
<tr>
<td>• Alberta Sustainable Resource Development (SRD) administers surface land access on most public land, and regulates reclamation on public lands.</td>
<td>• The OGC authorizes short-term (≤12 months) surface and subsurface water use for oil and gas activities, whereas the Ministry of Forests, Lands and Natural Resource Operations is responsible for long-term water surface water licenses.</td>
<td>• The State Engineer’s Office (SEO) allocates permits for all surface and ground water use.</td>
<td></td>
</tr>
</tbody>
</table>

### NOTE: Alberta government is planning to integrate the ERCB and relevant portions of AE&W and SRD into a single oil and gas regulatory agency |

<table>
<thead>
<tr>
<th>Overview of application and approval process for unconventional resource development projects involving hydraulic fracturing operations.</th>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>• A licence required from ERCB to construct or operate petroleum industry energy developments including wells.</td>
<td>Fracturing operations conducted at a depth of 600 m or less must be approved in the well permit. Applicants for shallow fracturing operations are required to conduct risk assessment including, as a minimum:</td>
<td>• No distinctions between conventional vs. non-conventional</td>
<td></td>
</tr>
<tr>
<td>• Hydraulic fracturing not subject to separate license; seen as part of a well completion process, subject to reporting requirements.</td>
<td>• fracture program design including proposed pumping rates, volumes, pressures, and fracturing fluids,</td>
<td>• recently WY has gone to horizontal drilling and enhanced hydraulic fracturing.</td>
<td></td>
</tr>
<tr>
<td>• Injection wells regulated by the ERCB, and handling of all fluids on the well-site.</td>
<td>• estimate of maximum fracture propagation,</td>
<td>• CBM needs separate regulation and protection because coal seams are also very shallow potable aquifers – under approval of SEO as well as WOGCC.</td>
<td></td>
</tr>
<tr>
<td>• AE&amp;W approves water allocations.</td>
<td>• identification and depth of all water wells within 200 m of the proposed fracturing operations,</td>
<td>• All hydraulic fracturing operations require approval prior, either as part of initial drilling permit, or as a separate step; CBM an exception</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• verify cement integrity of all wells within 200 m of</td>
<td>• no hydraulic fracturing allowed,</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Are unconventional resource development approvals for individual wells? Do you require a separate application for schemes or projects? | • potential environmental issues such as impacts on caribou, water diversions, types of water diverted, cumulative effects  
• timeliness of authorizations.  
• Unconventional resources entail larger surface footprint,  
• Emerging issues: integrity of casing and cementing in wells in proximity to wells undergoing hydraulic fracturing  
• Demonstrating effective regulation pertaining to the potential impacts on waters - protection of groundwater and withdrawal of surface water.  
• Need for base-line studies on groundwater - sources and availability of potable water.  
• Better flow information needed on northern rivers.  
• Addressing public concern  
• The lack of registration of water wells makes it more difficult to monitor  
• 80 acre spacing between wells,  
• casing cemented to surface.  

| What have been the most important challenges presented by unconventional resource development? How | • may apply for multiple wells on a single drill pad on a single application.  
• individual wells require separate approvals,  
• spacing may be done on an area basis.  
• Each stage of a multiple stage well stimulation requires separate notification  
| 80 acre spacing between wells,  
• casing cemented to surface.  

Regardless of whether the well is conventional or unconventional, well design and construction is paramount. Cement integrity, cement bond logs and the use of API Standards must be required.
**have you addressed these?**

- fracturing. Some proximate wells are completed to different standards than exist today, and some legacy wells may need to be reviewed and monitored.
  - Looking at modeling prior to fraccing, and analysis of fracture propagation (microseismic).

Consultation and notification to water well owners challenging.

**What communication tools are used, and by whom, to educate the public about hydraulic fracturing and the issues being raised?**

- recent new publications on ERCB website targeted to public.
- information and publications on website outline role and regulation.
- Fracfocus.ca website to inform on fracturing fluid ingredients.
- technical reports published on OGC website.
- public meetings and presentations.
- publicly-accessible data base published online.

**Table A-2: Drilling and Completion Operations: Casing and Cementing**

<table>
<thead>
<tr>
<th></th>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
</table>
| **Depth of casing** | Surface casing depth is a function of reservoir pressure and TVD, always minimum 25 m deeper than deepest water well within 200 m radius. | Surface casing set in a competent formation at a depth sufficient to provide a competent anchor for blowout prevention equipment. 
  - ensure control of anticipated well pressures 
  - must be cemented to the surface. 
  - The next casing string is cemented full length if surface casing is not set below the base of all porous strata that contain usable groundwater or to a minimum depth of 600 m. 
  - required to maintain hydraulic isolation between | Surface casing shall be run to a depth below all known or reasonably estimated utilizable groundwater 
  - Installation must prevent blowouts or uncontrolled flows. 
  - Surface casing shall be a minimum of 3 joints or approximately 100-120 ft. below the depth of any permitted water supply wells designated for domestic, stock water, irrigation or municipal use, within a minimum of 1/4 mile radius 
  - must be cemented to surface. |
| Regulations for next string of casing (how many strings—is casing done right up to the surface)? | No specific requirements for hydraulically fractured wells. Legacy wells may not meet current requirements. | Shallow wells:  
- a single casing string provided adequate zonal isolation is achieved.  
Deeper wells:  
- surface and production casing required.  
- intermediate casing not required; dependant on drilling needs (ie, to isolate lost circulation zones). |
|---|---|---|
| | | Pressures and formations are unknown:  
- surface casing shall be of sufficient size to permit the use of an intermediate string or strings of casing.  
- Surface casing shall be set in or through an impervious formation  
- Surface casing shall be cemented by the pump and plug or displacement or other approved method  
- cement must fill the annulus to the top of the hole.  
- Supervisor may require pumping of excess cement, above design volume, if severe washed out conditions exist on surface hole portion wells in immediate vicinity of well being drilled.  
- If cement is not circulated to surface during primary operation, supplemental cementing shall be performed to fill the annular space from casing shoe to surface.  
- Depth of all casing strings shall be based on formation fracture gradients and maximum anticipated pressure to be maintained within the wellbore.  
- If necessary to run production string, it shall be cemented by pump and plug method and be tested. |
<table>
<thead>
<tr>
<th><strong>Do parameters exist for quality of cement?</strong></th>
<th><strong>Techniques to confirm integrity of the cementing and casing (i.e., cement bond logging &amp; pressure testing)?</strong></th>
</tr>
</thead>
</table>
| - Directive 9: cementing requirements for casing:  
- conditions for special cements  
- Must meet API specifications.  
- Conductor pipe (not mandatory in all cases) and surface casing to be cemented full length.  
- Liners shall be cemented full length.  
- If surface casing < 180 m depth or < 25 m below a useable aquifer, production or intermediate casing shall be cemented full length.  
- Otherwise, production or intermediate casing cemented to minimum 100 m above the geologic zone. | - Logging required to provide geological mapping and characterization of the shallow strata  
- All Wells Drilled after Dec 1, 2006 require an acceptable log within the surface casing interval, to measure:  
  - Natural gamma ray response through casing from base of surface casing to surface, and  
  - Neutron response through casing from base of surface casing to 25 m below surface.  
- Before completion, abandonment or suspension of drilling operations, an acceptable log measuring the resistivity and spontaneous potential of the strata from total depth of well to base of surface casing. |
| - Cementing information reported on end of well report and reviewed by OGC Drilling Engineer.  
- If doubt about the effectiveness of cementing, must investigate the cement integrity and remediate as necessary. | - Evaluation of cement integrity not required if cement returns to surface during the cementing operation.  
- If no cement returns, bond logging is required to evaluate the cement and locate top of cement. |
| **by pressure method before cement plugs are drilled.** | - May be required to provide cement bond logs if loss of cement, bad hole conditions.  
- Require use of API grade cement.  
- Excess cement may be required if severe washed out hole conditions are known.  
- may require cased hole bond logs to be run to demonstrate isolation from the placement of cement across and above the productive intervals or above the last casing shoe in the well only completed if there is a demonstrated reason to believe cement is inadequate  
- casing outside the tubing of injection or disposal wells shall be tested at either 300 psi or a pressure equivalent to the maximum injection pressure, whichever is greater, to a max of 1,000 psi.  
- packers must be set within 100’ of perforations for |
- WOGCC staff must be provided opportunity to witness integrity tests.
- If WOGCC does not witness the test, documentation of the test must be provided.
- A retrievable bridge plug will be utilized in casing to test tubingless completions.

Table A-3: Testing of Water and Water Wells

<table>
<thead>
<tr>
<th>Is baseline groundwater testing required?</th>
<th>What is the radius required for baseline testing</th>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>no fracturing operations at depths &lt;200 m unless:</td>
<td>• fracture program design is fully assessed,</td>
<td>• notification of water well owners within 200 m of proposed operations,</td>
<td>• Not required, recommended in areas with populations or reservoir and aquifer are in close proximity.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• maximum propagation expected for all fracture treatments is determined,</td>
<td>• pre and post-fracture sampling of water wells within 200 m of proposed operations where agreed by water well owners.</td>
<td>• UIC (underground injection control) wells need to examine all wells within ½ mile.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• identification and depth of target formation and water wells within 200 m of the proposed shallow fracturing,</td>
<td></td>
<td>NOTE: Authorities indicate many of the problems they have experienced with water well contamination is a result of surface migration downwards due to poor construction practices.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• verification of cement integrity of all oil and gas wells within 200 m of the well to be fractured,</td>
<td></td>
<td>DEQ Guideline recommends property owners negotiate pre-and post-drilling water well testing, as a condition to mineral lease, or surface use agreement.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• notification of active water well owners within 200 m of the proposed fracturing operations</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>NOTE: Companies are encouraged to voluntarily collect baseline data for water wells in close proximity to an energy development prior to drilling and submit data to AE&amp;W.</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>---------------------------------------------------------------</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**What chemical parameters are tested for in the water?**

- AE&W Standard only applies to CBM development above the BGWP wells
- Analyses must be provided to AE&W and landowner/occupant.
- Testing program must be carried out under the direction of a professional engineer and requirements include:
  - water well capacity,
  - water quality including potability,
  - bacteriological analysis, presence and analysis of gas (including methane).  
- No specific requirements. Any testing requirements would be developed on a case-specific basis.

**DEQ Guideline recommends:**

- Tier 1 (Safe Drinking Water) constituents include EPA *National Primary Drinking Water Standards* including aesthetic parameters (taste, odor, etc.), microorganisms, metals, inorganic minerals, chemical compounds, organic chemicals, and radionuclides.
- Tier 2 constituents include: conductivity, pH, Total Dissolved Solids (TDS), alkalinity, barium, calcium, magnesium, sodium, chloride, sulfate, fluoride, nitrate, lead, arsenic, iron, and total organic carbon.
- Tier 3 constituents: ‘indicator’ chemical compounds associated with a potential source of contamination.
- Water well testing conducted by a certified laboratory and samples collected by an unbiased professional.

**How are the minimum standards determined? What are the minimum standards for water testing i.e. chemicals, metals, and anions?**


  N.A.

- The DEQ Guideline recommends the following relatively inexpensive ‘indicator’ analytes, parameters, and chemical compounds may provide basis for monitoring potential effects of oil and gas development:
  - Mineral and metal indicators: conductivity, pH, Total Dissolved Solids (TDS), alkalinity, barium, calcium, magnesium, sodium, chloride, sulfate, fluoride,
nitrate, lead, arsenic, iron, and total organic carbon. 
- Chemical indicators: TPH-DRO and TPH-GRO (Total Petroleum Hydrocarbons – Diesel Range Organics and Gasoline Range Organics); and BTEX (Benzene, toluene, ethylbenzene, and xylenes).

| Is a public complaint process in place? | YES. If a change in well water quantity or quality after CBM development is perceived, the water well must be retested in accordance with a retesting program.  
AE&W has a public complaint line. If oil and gas related, referred to ERCB for technical assistance.  
ERCB has 24 hour public complaint line at field offices. | If concerns raised re effects of operation on water wells, OGC may require pretesting for quantity and quality.  
Testing can be stipulated as a condition in individual oil and gas well approvals but not a legislated or policy requirement. | Complaints can be lodged at anytime, by phone, letters, etc.  
Also, can comment during rule-making process. |

| Post-operation monitoring—how long is monitoring done for? Is monitoring required throughout the drilling process? | Not required.  
ERCB requires:  
ongoing self-audits on oil and gas well completions above BGWP, and  
reporting for all water wells >30 m³ per month completed above the BGWP; NOTE: report may trigger actions. | Not required.  
requirements may be imposed on a case-specific, basis. | Not required.  
requirements may be imposed on a case-specific, basis. |

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**Table A-4: Hydraulic Fracturing and Injection Fluids**

<table>
<thead>
<tr>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
</table>
| Control Wells for Shale Gas Production? | YES. No shale gas production permitted unless ERCB has designated (a) a control well within 5 km of the producing well, NOTE: Operator may request designation from OGC to | No.  
NOTE: Some companies drill “monitor” wells to | No. |

17
to measure pressure and production in each shale zone, and a control well within 30 km of the producing well, for desorption testing. 

NOTE: This requirement is under review. Directive 40 states there are few shale gas control wells established to date, and further elaboration on the testing requirements for these wells is still under development.

**NOTE:** This requirement is under review. Directive 40 states there are few shale gas control wells established to date, and further elaboration on the testing requirements for these wells is still under development.

<table>
<thead>
<tr>
<th>Requirements for the fracturing (well injection) process?</th>
<th>• No separate authorization required to hydraulically fracture a well unless using HVP (high vapour fracs) which have safety considerations.</th>
<th>• All hydraulic fracturing operations require prior approval prior, either as part of initial application, or as amendment.</th>
</tr>
</thead>
</table>
| Geologic prognosis design required prior to the hydraulic fracturing process? | • Not required to be submitted. Expect industry to prepare drilling program and hydraulic fracturing design, as part of industry best practises. 
• Core must be submitted if core sample collected 
NOTE: Legislation allows ERCB to ask for information to be submitted. | • Not required to be submitted. See above re risk assessment requirements for fracturing operations conducted at less than 600 m depth. 
NOTE: Companies typically do ‘mini-fracs’ to help design fracture appropriate to rock, following industry best management practices. Some of this information might be in special project applications. | • Not required to be submitted. 
• Formation tops required with drilling permit application. Information used to help design well. |
| Is there a need to do microseismic testing/tracking? | • Not required on all wells. 
• If conducted, must be recorded on daily drilling and completion reports (see Directive 59). 
NOTE: Industry may conduct on initial wells to understand fracture propagation and apply information to subsequent wells, so not done on every well. | • Not required 
• Increasing number of operators undertaking microseismic monitoring to map hydraulic fractures. | • Not required 
• Some companies are doing this to monitor hydraulic fractures. |
<p>| Volumes of water | • Slickwater fracturing ~50,000 m³ per fracture. | • 10,000-25,000 m³ per well in Montney Play, | • Ranges from few hundred gallons to 1-2 million |</p>
<table>
<thead>
<tr>
<th>Question</th>
<th>Cardium Formation</th>
<th>Horn River Basin</th>
<th>Gallons, and from single stage to 30 stages.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tight oil fracturing in the Cardium Formation ~1000 m³ per fracture.</td>
<td>25,000-75,000 m³ per well in Horn River Basin.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| What is the base fluid used for hydraulic fracturing procedures in your jurisdiction? | Mostly water. | Water, nitrogen, propane, and diesel have been used. | >90% is water (slick water, chemicals to reduce friction). Diesel is rare, only in isolated formations. Nitrogen and foam often used. |
| Oil plays use mostly hydrocarbons. | Fracturing with diesel is rare. | For shale gas, water is the most common. |

| What proppant is used? | Primarily sand | Primarily sand. | Primarily natural sand. |
| Primarily sand. | Ceramics. | |

| Is pressure-testing likely to be done prior to the fracturing procedure? | Not required. | Not required. | Not required. |
| Operator may do as a standard best practice to establish formation break-down pressure before fracturing. | Casing pressure tests are generally done pre-hydraulic fracture by operator. | Companies may voluntarily test casing. Disposal Injection wells are tested every 5 years at injection pressure. |

| Does your jurisdiction require disclosure of fracturing fluid composition? Is this information publicly available and if yes, how? | Directive 59 (Appendix 3) requires fluid analysis to be disclosed. If an incident occurs, ERCB has authority to get the information. Only non-toxic fracture fluids permitted above the base of groundwater protection. Upon request, licensees must supply the ERCB with the composition of the fracture fluids for CBM. NOTE: Alberta is currently enhancing Dir. 59 to get information submitted in consistent format so it can be posted to public. Since our interview Alberta has announced to will be requiring all fracturing fluids to be posted on Fracfocus.ca | Effective Jan 2012, mandatory disclosure is required and data is publicly available on Fracfocus.ca. | Must provide base fluid source and chemical additives, compounds and concentrations or rates proposed to be mixed and injected for each well stimulation stage, including: Fluids identified by additive type (e.g. acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, surfactant); Chemical compound name and Chemical Abstracts Service (CAS) number for each additive used. Proposed rate or concentration for each additive (e.g. lbs. per ‘000 gallons, or gallons per ‘000 gallons, or expressed as % by weight or % by volume). |
### Table A-5: Well Spacing

<table>
<thead>
<tr>
<th>Jurisdictions</th>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
</table>
| How is well spacing regulated? How is it changing with the development of unconventional resources? What criteria are used to determine appropriate spacing? | - No longer regulated.  
- Increased density required to enhance recovery due to tight formations.  
- Surface footprint of high well density reduced because of horizontal wells and multi-well pads. | - Spacing is regulated.  
- Oil well spacing is 1 per 1/4 section (approximately 65 hectares); Gas well spacing is 1 per section.  
- Subsurface resource (well spacing and target areas, production controls) is regulated through Special Project orders.  
- Good Engineering Practice (GEP) orders and Other Than Normal (OTN) Spacing orders prescribe well density and spacing controls within an area, including a buffer to boundaries. A GEP & OTN order size may be for a single gas spacing area, or an area that includes hundreds of normal spacing areas.  
- Obtaining GEP project status or a Utilization Agreement releases operator from regulatory requirements. | - Oil and Gas Rules set out general rules respecting spacing and locating of wells, and provides authority to authorize exceptions.  
- Generally 640 acres however acreage and shape of drilling units shall be determined by the WOGCC from evidence provided but shall not be smaller than maximum area that can be efficiently drained by 1 well.  
NOTE: Experimenting with 1280 acre and 320 acre spacings. |
| Well set-backs and separation distances | - 100 m from surface water body or from surface improvements (alternatively, non-routine approval for closer proximity).  
- 200 m from public dwellings | - <100 m to the natural boundary of a surface water body, or >100 m from the natural boundary of a surface water body but situated so that an uncontrolled flow of oil, gas, or another fluid may | - Minimum 350’ separation between pits, wellheads, pumping unit’s tanks or treaters and water supplies, residences, schools, hospitals or other structures where people are known to congregate. |
Table A-6: Regulatory requirements related to water use for drilling and hydraulic fracturing

<table>
<thead>
<tr>
<th>Trigger for water withdrawals (does water withdrawal over a certain amount trigger regulatory requirements?)</th>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>• AE&amp;W under the Water Ministerial Regulations distinguishes between temporary and permanent water permit.</td>
<td>• Groundwater withdrawal rates exceeding 75 L/s requires an Environmental Assessment under the Environmental Assessment Act (no distinction between saline and non-saline water).</td>
<td>• All water utilizations require a permit from the State Engineer’s Office (SEO). Most oil and gas operations use groundwater.</td>
<td></td>
</tr>
<tr>
<td>• 5000 m³ triggers the requirement for a water diversion approval on Crown lands,</td>
<td></td>
<td>• Temporary permit may be obtained for use of an existing groundwater right. Temporary use agreements with existing right holders must be approved by SEO and cannot exceed amount of historical use (not permitted use) under the existing permit.</td>
<td></td>
</tr>
<tr>
<td>• All other lands, any freshwater (TDS &lt;4000 mg/litre) use requires water diversion approval.</td>
<td></td>
<td>• A permanent change in use requires application to Water Court and is a lengthy process.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>What best practices in place for water withdrawal practices? What withdrawal</th>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Must investigate all reasonable alternatives, potential impact on other water users and impact on aquatic ecosystems.</td>
<td>• Results based regulation, does not specify method of water withdrawal.</td>
<td>• Metering and reporting requirements exist for all permits.</td>
<td></td>
</tr>
<tr>
<td>• Subject to public notice.</td>
<td>• 2 methods commonly used:</td>
<td>• Backflow prevention device requirements were implemented on source water wells to prevent contamination from haul trucks.</td>
<td></td>
</tr>
<tr>
<td>NOTE: Saline water (&gt;4000ppm) is exempt from Water Act approvals.</td>
<td>• pump water from a surface water source into temporary surface lines.</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>method is generally recommended?</strong></td>
<td><strong>Screening requirements in place?</strong></td>
<td><strong>Are potential impacts on other users of the water considered?</strong></td>
<td></td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-------------------------------------</td>
<td>----------------------------------</td>
<td></td>
</tr>
<tr>
<td>Surface water is pumped into a water truck then transport to destination.</td>
<td>Intake screens meeting Fisheries and Oceans Canada (DFO) criteria based on pumping rates are required.</td>
<td>Yes. Restrictions on withdrawal may be imposed based on senior water rights holders.</td>
<td></td>
</tr>
<tr>
<td>Are potential impacts to the aquatic ecosystem considered?</td>
<td>Domestic users have priority over industrial/commercial users in situations where withdrawals may be impacted by drought etc.</td>
<td>First in/first out. Oldest rights are honoured first. Principle of “no injury may occur to other users” -- including other rights holders, aquifers. Also, includes injury from contamination or excessive drawdown.</td>
<td></td>
</tr>
<tr>
<td>Yes.</td>
<td>Industry is expected to demonstrate their use of water will not adversely impact riparian habitat or fish resources.</td>
<td>Yes. Industry is expected to demonstrate their use of water will not adversely impact riparian habitat or fish resources.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Consideration must be given to seasonal timing, recreational use, water availability, First Nations consultation, other permitted users, and potential impact to shoreline habitat.</td>
<td>Or commercial users in situations where withdrawals may be impacted by drought etc.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>OGC may request additional information, such as fish/aquatic/shoreline habitat assessments, and bathometric and hydrological analyses.</td>
<td>Principle of “no injury may occur to other users” - including aquifers. Do not permit any user to contaminate aquifer or unreasonably interfere with aquifer productivity.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>OGC may prescribe additional project specific mitigation measures as permit conditions.</td>
<td>NOTE: A water allocation does not give permission to disturb or damage any soil, trees, stream bank or lakeshore, existing works or other property, construct works to transport water from the source location to a storage facility or the use site, construct any in-stream works, remove water from any beaver pond, damage</td>
<td></td>
</tr>
</tbody>
</table>
or destroy an aquatic furbearer dam, house or den, upgrade or create access to facilitate water withdrawal or enter private land in order to gain access to a diversion point.

Are aspects such as percentage of flow and/or regular maintenance flow considered?

- Permit can include provisions like maximum diversion rates to protect instream flow needs and protect the aquatic environment.
- Water approvals contain:
  - minimum flow requirements,
  - maximum drawdown on natural waterbodies,
  - maximum daily allowable withdrawal,
  - maximum total allowable withdrawal.
  - water withdrawal during low flow conditions is prevented - OGC can suspend approvals when water levels in watercourses become too low.

NOTE: The OGC plan to implement requirements for the maintenance of flows.

- Contamination of aquifer or unreasonable interference with aquifer productivity is not permitted by any user.

Table A-7: Flowback Fluids Handling and Disposal

<table>
<thead>
<tr>
<th>What is the on-site storage system of flowback/produced water (such as double-walled tanks?)</th>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td>Directive 55 2011 addendum supports managing of large slickwater fracturing fluids by use above ground synthetically lined storage systems (c-rings). Directive 58 requirements for the handling, treatment, and disposal of upstream oilfield waste, provides classification and tracking of oilfield waste requirements for oilfield waste management facilities.</td>
<td>Earthen pits used to store liquid waste must be: (a) located &gt;100 m from the natural boundary of a water body, (b) located &gt;200 m of a water supply well, (c) constructed of clay or other impermeable material with the pit bottom above ground water level, (d) located or ditched so that it will not collect natural run-off water, (e) filled &lt;1 m below the point of overflow at any given time, and (f) completely emptied and any excavation filled</td>
<td>Minimum 2’ of freeboard required on all pits. Fencing and netting of pits to keep wildlife out. Approval required for all pit or below grade structure used to contain fluids Lining of pits with reinforced oilfield grade material, compatible with the waste is required under certain circumstances including pits to be constructed in critical areas as well as on sandy soil sites, areas of shallow groundwater, groundwater recharge areas, or sites immediately adjacent to the Green River or Colorado River and other sensitive environments or circumstances identified by the WOGCC.</td>
<td></td>
</tr>
</tbody>
</table>
|  | without unreasonable delay.  
|---|---|
| • Fracture fluid returns may be stored in closed top tanks only  
| • Slickwater fracture fluid returns may be stored in open top tanks or lined, earthen excavations.  
| • Storage of fracture fluid returns in open and closed top tanks is limited to 90 days from the completion of servicing operations unless otherwise approved.  
| • Use of Tank Requirements:  
| • Sites must be bermed to ensure fracture fluids will not migrate off site in the event of tank failure. Berm may surround the entire site or tanks only.  
| • Open top tanks must maintain at least 1 m freeboard at all times.  
| • Primary containment for open top tanks may be provided by an impermeable synthetic liner if design is certified by a professional engineer.  
| • Open top tanks must be inspected monthly for leakage and damage.  
| • Use of Lined Earthen Excavations Requirements:  
| • Must be constructed with a primary containment device, a secondary containment device, both constructed of impervious synthetic liners, a leak detection system between the primary and secondary containment devices,  
| • Adequate fencing to prevent wildlife access and unauthorized dumping, and  
| • Signage at the access point identifying the  
| | Pits constructed in Powder River Basin for percolation of CBM produced water into shallow sands or aquifers may be considered if it can be demonstrated discharge will comply with DEQ water quality standards  
| | Pits constructed in fill or used to retain oil base drilling muds, high-density brines, and/or completion or treating fluids must be lined.  
| | Pits constructed to retain produced water with a TDS concentration > 10,000 mg/l must be lined.
| How are the piping (transfer) systems set up? End of Pipe Standards for discharge - ie, do they ship to a third party to treat? If and how are facilities that treat wastewater approved? | If Pipelines are used, they must be approved, usually temporary, on surface  
Saline water may be disposed of into same reservoir as it was obtained. | fluid tanks → blend truck → pumps → disposal wellhead. |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>What monitoring is</td>
<td>Volume of flowback fluids must be measured and</td>
<td>• Completed by service company, who submits post-</td>
</tr>
</tbody>
</table>
| done for quality and quantity (flow rate and chemical composition)? Long-term monitoring of the storage system? | reported.  
- No requirements for monitoring chemical composition of flow back fluids. | fracturing report. |
|---|---|---|
| **Techniques used to treat, dispose, and recycle used water** | • Encourages use of borrow pits, and recycling of fluid flowback.  
• No NORM waste handling requirements in AB, or testing to identify NORM content; Health Canada has standards for NORMs relating to worker safety. | • Flowback may be disposed of or treated and re-used for subsequent fracture operations.  
• Treatment at licensed waste treatment facility injection to the subsurface through a licensed disposal well.  
• Tanks may be closed top, open top and lined, earthen excavations.  
• No surface discharge of produced.  
• Flowback may be stored in closed top tanks.  
• Only slick water flowback may be stored in open top tanks or lined, earthen excavations.  
• Registration of earthen excavations required. | • Must provide  
- geological names,  
- geological description  
- depth of the formation where stimulation fluids are to be injected,  
- amounts of flowback,  
- Handling procedures for flowback  
- if necessary, identification of appropriate disposal facility,  
- information on reuse of the well stimulation fluid load recovered during flow back, swabbing, and/or recovery from production facility vessels. |
| **Deep-Well Injection: is this practice used, and how is it regulated?** | • Injection wells are classified; design, operating and monitoring requirements are consistent with type of fluids disposed.  
• Regulated under Directive 51, outlines testing and submission requirements. | • Wastewater is recycled to enhance resource extraction, such as reinjection into oil and gas pools to produce oil and natural gas.  
• Wastewater is disposed of in an injection well.  
• Surface discharge not allowed.  
• Disposal wells are subject to permitting under OGAA. | • Approvals issued for injection wells for disposal of fresh, salt or brackish water, or other water unfit for domestic, livestock, irrigation, or other general uses.  
• Permit applicant required to demonstrate proposed disposal operation will not endanger fresh water sources.  
Injection wells shall be cased and cemented in a manner to protect oil, gas and fresh water.  
NOTE: Recycling is still a fledgling activity, driven by economics. |
<table>
<thead>
<tr>
<th>Applications for disposal wells shall include:</th>
</tr>
</thead>
<tbody>
<tr>
<td>• A well location plan, including identification of</td>
</tr>
<tr>
<td>existing and abandoned wells and dry holes, names of</td>
</tr>
<tr>
<td>all lease Operators or Owners and surface owners</td>
</tr>
<tr>
<td>within a 1/2 mi of the proposed disposal well;</td>
</tr>
<tr>
<td>• An affidavit signed by surface owners within a</td>
</tr>
<tr>
<td>1/2 mile radius stated they have been provided a</td>
</tr>
<tr>
<td>copy of the application;</td>
</tr>
<tr>
<td>• The names, description, and depth of the</td>
</tr>
<tr>
<td>injection formation target, including a</td>
</tr>
<tr>
<td>mechanical log of proposed injection well, if</td>
</tr>
<tr>
<td>available;</td>
</tr>
<tr>
<td>• Description of casing, or proposed casing</td>
</tr>
<tr>
<td>program and proposed method for testing casing</td>
</tr>
<tr>
<td>before use;</td>
</tr>
<tr>
<td>• Source of water to be injected;</td>
</tr>
<tr>
<td>• Estimated daily water injected;</td>
</tr>
<tr>
<td>• Average and maximum injection pressure;</td>
</tr>
<tr>
<td>• Data showing the proposed injection well will not</td>
</tr>
<tr>
<td>initiate fractures in the overlying strata or</td>
</tr>
<tr>
<td>confining zone which could enable fluid to</td>
</tr>
<tr>
<td>migrate to overlying strata;</td>
</tr>
<tr>
<td>• Laboratory analysis of water to be injected and</td>
</tr>
<tr>
<td>water in target formation</td>
</tr>
<tr>
<td>• 1/4 mile radius integrity investigation of wells</td>
</tr>
<tr>
<td>which penetrate the disposal zone</td>
</tr>
<tr>
<td>• Depth and areal extent of fresh and potable</td>
</tr>
<tr>
<td>water (USDW) underlying area proposed for</td>
</tr>
</tbody>
</table>

| well location plan, including identification of |
| existing and abandoned wells and dry holes, names of all lease Operators or Owners and surface owners within a 1/2 mi of the proposed disposal well; |
| An affidavit signed by surface owners within a 1/2 mile radius stated they have been provided a copy of the application; |
| The names, description, and depth of the injection formation target, including a mechanical log of proposed injection well, if available; |
| Description of casing, or proposed casing program and proposed method for testing casing before use; |
| Source of water to be injected; |
| Estimated daily water injected; |
| Average and maximum injection pressure; |
| Data showing the proposed injection well will not initiate fractures in the overlying strata or confining zone which could enable fluid to migrate to overlying strata; |
| Laboratory analysis of water to be injected and water in target formation |
| 1/4 mile radius integrity investigation of wells which penetrate the disposal zone |
| Depth and areal extent of fresh and potable water (USDW) underlying area proposed for |
exemption; Under the Safe Drinking Water Act regulates injection of fluid into the subsurface.

DEQ delegated by EPA under Safe Drinking Water Act to regulate Class I, III, IV and V UIC facilities.

OGCC has regulatory authority for Class II wells.

UIC Program defines five classes of facilities:

- **Class I**: DEQ - Disposal of Industrial, Commercial or Municipal waste below deepest usable aquifer.
- **Class II**: OGCC - Disposal of oil and gas industry wastewater.
- **Class III**: DEQ - Injection wells for recovery of minerals.
- **Class IV**: DEQ - Facilities which dispose of hazardous waste into or above any usable aquifer – not allowed in Wyoming.
- **Class V**: DEQ - All other fluid injection facilities, including CBM produced water.

Are techniques such as secondary containment, berms, tanks with liners used?

- Directive 55 and addendum re use of tanks and above ground synthetically lined storage systems
- Size limited to 3000 m3
- Only primary containment required.

- OGC standard is as follows:
  - Secondary containment for tanks <45.4 m3 storing chemicals, fuel, or other products on a wellsie equalling 110% of tank volume or be either double walled
  - Tanks <1 barrel in size do not require secondary containment
  - Tanks >45.4 m3, require dyking or berming.

- Pits must meet or exceed the following construction standards:
  - Soil mixture liners, recompacted clay liners, and manufactured liners compatible with the waste contained.
  - Evidence liner is chemically resistant must be provided upon request.
  - Synthetic liners must meet the following:
    - 9 to 12 mil thickness,
- greater than 20% elongation at failure,
- puncture strength of 60 lbs,
- tear strength of 50 lbs,
- permeability less than 10-7 cm/sec.
- Joints must be overlapped minimum of 2” and seams sealed as recommended by manufacturer.
- Blemishes, holes, or scars must be repaired per manufacturer’s recommendation.
- Breaches in the liner for siphons or other equipment must be reinforced.
- Slopes for soil mixture liners or recompacted liners shall not exceed 3:1.
- Slopes for manufactured liners shall not exceed 1:1.
- Include reasonable provisions for protection of liners during filling and emptying.
- Manufactured liners must be installed over smooth fill subgrade free of pockets, loose rocks, etc. which could damage liner.
- No organic material except synthetic cushion fabric designed for that purpose may be used for a liner cushion.
- Installation of synthetic or soil mixture liners must be in accordance with accepted engineering practice.
- Liner edges must be secured and liner edges placed in a trench which is deep enough to receive approximately 1’ of compacted soil to anchor the material.
| Are storage ponds allowed as an option? | Yes. Must be lined.  
Must be engineered with dual synthetic liners  
Requires interstitial leak detection as per OGC IL 09-07, Storage of Fluid Returns from Hydraulic Fracturing Operations. | YES. Freshwater only.  
Soil mixture liners, recompacted clay liners, and manufactured liners must be compatible with the waste contained.  
Must provide evidence of the chemical resistance of liner if requested. |
|--------------------------------------|-------------------------------------------------|-----------------------------------------------------------------|
| Is baseline soil testing required at the well-site? | 1. No entire site liner required.  
2. No baseline soil testing drilling sites. | No baseline soil testing required.  
No requirement for a geomembrane liner for drilling practices. | No. |
Requirement for a geomembrane liner for drilling practices?

NOTE: In practice, liners are used whenever invert drilling muds are used to meet requirement that drilling wastes do not:
- threaten public health or safety;
- contaminate any water supply well, usable aquifer or water body or be placed where a usable aquifer or water body may get contaminated;
- pollute or damage any land or public road;
- pass into or, on ice, over any water body frequented by fish or wildlife or that flows into such a water body.

Table A-8: Environmental Impacts Caused and Public Concerns Associated with Hydraulic Fracturing

<table>
<thead>
<tr>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
</table>
| Documented negative environmental occurrences associated with hydraulic fracturing? | Three issues have arisen:  
1. Communication between wells - have caused worker safety concerns.  
2. Sand erosion of surface equipment - have caused gas releases in some wells in BC.  
NOTE: Sand management plans required, outline steps to reduce, monitor and capture sand returns, incorporate leak detection and piping integrity testing. Plan must include:  
• de-sanding equipment  
• piping configurations to minimize erosion  
• velocity control  
• ultrasonic testing | EPA Draft Investigation of Ground Water Contamination Near Pavillion, Wyoming, Dec 2011 reported ground water contamination detected likely caused by hydraulic fracturing. Final Report pending  
• Gas and aquifer often share a common zone. Classification as a water or gas well depends on the relative proportions of each. A water well can become a gas well if the water column is drawn down allowing gas to enter. |
<table>
<thead>
<tr>
<th>Negative environmental occurrences associated with conventional well operations in your area?</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Contamination caused historically by earthen production fluid pits still persists.</td>
</tr>
<tr>
<td>• Surface spills</td>
</tr>
<tr>
<td>• well blow outs (loss of control).</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Types of concerns being raised by landowners, communities, and interest groups?</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Trucks, noise, water.</td>
</tr>
<tr>
<td>• Water use, Emissions/ flaring, surface footprint, safety traffic, noise, wildlife.</td>
</tr>
<tr>
<td>Degradation of water wells, quality and quantity. CBM and aquifer proximity gas encountered when drilling a water well. NOTE: Rural, dry state which relies on groundwater.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>How are these concerns considered in the regulatory process? Do you require public consultation? At what point in the process?</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Public Consultation and notification requirements prescribed by regulation.</td>
</tr>
<tr>
<td>• No different requirements respecting hydraulic fracturing operations.</td>
</tr>
<tr>
<td>• No public comment re EPA study.</td>
</tr>
<tr>
<td>• Public consultation required for injection wells.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>What measures are being implemented to mitigate these concerns? Have you modified approval processes for unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Guidelines and Directives introduced to adopt basin management approach to unconventional development,</td>
</tr>
<tr>
<td>• Looks at water withdrawals on larger scale, larger impacts on land surface – eg, wildlife, caribou, air emissions, cumulative effects.</td>
</tr>
<tr>
<td>• Proposed EPA rules may require public notice/comment period.</td>
</tr>
<tr>
<td>Questions</td>
</tr>
<tr>
<td>--------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| resource development to accommodate greater public concern?             | • Water, including sourcing and protection.  
• Cumulative effects, including footprint management and mitigation.  
• Number of trucks, including idling emissions at fracturing site.  
• Short-term air emission issue – eg extended flare period at start-up – depending on frac fluid used. 50% of flowback recovered in 1st week, 80% in 1st month. Most flaring for unconventional horizontal wells < 1 month (compared to < 1 week for conventional well).  
• Noise  
• Surface and ground water use/ protection  
• Introduced quarterly water reporting, on-line posting of short term water approvals;  
• Basin management of unconventional resources, looking at large scale water withdrawals, and larger impacts on land surface – eg, wildlife, caribou, air emissions, cumulative effects.  
• Protection of fresh water aquifers by ensuring proper casing to protect groundwater. |
| What are important environmental issues related to hydraulic fracturing operations in your jurisdiction and how are you addressing these issues? | • Earthquake issue has been raised. Alberta Geological Survey (AGS) has undertaken measurement and location of micro earthquakes studies (ie, not detectable by humans).  
• Would like to undertake a baseline groundwater sampling program in BC.  
• UBC studying life cycle of GHG emissions from shale gas activities.  
No.                                                                                                                                                                                                 |
| Does your jurisdiction have environmental issues related to hydraulic fracturing operations which need future work/research? If yes, what plans do you have? |                                                                                                                                                                                                          |
### Table A-9: Emergency Response, Site Restoration, Financial Security and Data Collection and Reporting

<table>
<thead>
<tr>
<th>Alberta</th>
<th>British Columbia</th>
<th>Wyoming</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Emergency Response Plan in place to help mitigate the risk?</strong></td>
<td>1. Emergency preparedness and response required 2. Additional requirements for sour gas wells, pipelines, production facilities and gathering systems; high vapour pressure (HVP) pipelines; spills of hydrocarbons and produced water; and hydrocarbon storage in caverns. 3. Adherence to CSA Standard Z-731 required.</td>
<td>1. Not Required. May be requested on a case by case basis. Sometimes ERP required for sour gas during drilling under OHSA.</td>
</tr>
<tr>
<td>• Directive 71 requires: 1. emergency response plans (ERPs) to respond to incidents presenting significant hazards to the public and environment. 2. trained personnel and proper equipment to carry out emergency response to incidents.</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>What site restoration requirements are in place once the drilling operation is completed?</strong></td>
<td>• Site required to be reclaimed to equivalent capability. • ERCB responsible for well abandonment. • AE&amp;W responsible for site reclamation. NOTE: Current tighter standards mean that newer sites are not likely a problem.</td>
<td>• Clean up of pits, recontouring and restoration to previous state required upon permanent abandonment of site. • Usually within 1 year of last approved use.</td>
</tr>
<tr>
<td>• Site reclamation requirements: (a) de-compacting soils compacted by activity; (b) redistributing stockpiled surface soils (c) restoring drainage patterns to condition before alteration; (d) re-vegetating exposed soil with a suitable species (e) removing watercourse/wetland crossing structures stabilizing site; (f) stabilizing any cut slopes or fill slopes.</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>What financial security is required to cover environmental liabilities? How is the amount of security determined?</strong></td>
<td>• Orphan site restoration tax based on volume of marketable gas production; eg, $0.03 per 10^3 m^3. • Compensation to landowners if the operator fails to reclaim site properly. • Security required using a Liability Management Rating (LMR) program to security deposits value. • LMR used in bi-monthly assessments, and permit transfer applications, to determine net worth of a company and its ability to withstand financial risk.</td>
<td>• Bonding requirements to ensure waste or damage is not caused to the environment and be plugged and permanently abandoned in accordance with the Rules and Regulations. • Minimum bonds required as follows: (i) wells &lt;2,000’ deep, $10,000; (ii) wells ≥2,000’, $20,000; or, (iii) Alternatively, $75,000 covering all wells. • The bond amount increases every 3 years based on the WY consumer price index. • May require a bond for produced water pits to ensure</td>
</tr>
<tr>
<td>• Directive 6 ensures well remediation &amp; abandonment costs are not borne by the government. • Ensures Orphan Fund (funded by licensees) is protected. • Security deposit required based on rating determined by process that compares value of licensee’s assets to liabilities.</td>
<td></td>
<td></td>
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<tr>
<td></td>
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</tr>
<tr>
<td>Question</td>
<td>Answer</td>
<td></td>
</tr>
<tr>
<td>-------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Different financial security requirements for large vs. small operations?</td>
<td>No.</td>
<td></td>
</tr>
<tr>
<td>For conventional vs. unconventional operations?</td>
<td>No. The liability of operation is measured against corporate balance sheet of operator.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>No. Extra bonding required for Temporarily Abandoned wells, to avoid risk of sale to party not capable of meeting obligations.</td>
<td></td>
</tr>
</tbody>
</table>
| Have you modified data submission requirements to accommodate hydraulic fracturing operations? | Directive 59 specifies record of daily operations must contain complete data hydraulic fracturing.  
• Submission requirements:  
  1) Fracture scenario: through casing or with a liner.  
  2) Proppant: types, quantity, size.  
  3) Carrier fluid:  
    type: water, hydrocarbons, acid, distillate, CO₂, N₂;  
    volume of fluid;  
    whether energized (N₂, CO₂, or both); and  
    source of carrier fluid.  
  4) Additives: name, supplier, purpose (eg, cross linker, breaker, buffer, etc.).  
  5) Feed rates: max and average.  
  6) Pressures: max and average treatment, and instantaneous shut in (ISIP), if determined. |
|                                                                         | Completion report must be filed within 30 days of end of operation.  
• Typical horizontal well may have 20 fracture stages.  
Fracturing reports from service providers are expected as part of the completion report.  
• Issues logging, sampling and reservoir pressure testing waivers on a regular basis to high density development of unconventional resources.  
NOTE: OGC has initiated development of online interface requiring operators to upload fracture stimulation information a public database. |
|                                                                         | No. All submissions are scanned and electronically accessible to the public.                                                         |

- Environmental damage does not occur
- Health and safety of employees and people residing close to the pit is not in jeopardy, and
- The pit is closed and reclaimed in accordance with the Rules and Regulations.
<table>
<thead>
<tr>
<th></th>
<th>Fracture extent and orientation measurements (eg, microseismic run).</th>
<th>Multistage fracture operations: Include all information listed in 1 - 7 per stage.</th>
<th>Service company job reports.</th>
</tr>
</thead>
<tbody>
<tr>
<td>7)</td>
<td></td>
<td>8)</td>
<td>9)</td>
</tr>
<tr>
<td></td>
<td>What do you believe is critical data and how is that data used to effectively manage the development of the resource?</td>
<td>Micro-seismic data and completion details.</td>
<td>Well design, casing, cementing are most important. Also, how fluids are handled at the surface, not too close to water bodies, streams.</td>
</tr>
</tbody>
</table>

What do you believe is critical data and how is that data used to effectively manage the development of the resource?

- Micro-seismic data and completion details.

What rules govern the confidentiality of industry-submitted data? Is unconventional resource data handled differently from conventional resource data?

- See Part 2 ‘Release of Information’ OGAA General Regulation for full details.
- No. Information can be confidential for 6 months from date of completion.
## Tables for New Brunswick, New York and Saskatchewan

### Table B-1: Overview of Regulatory Processes and Regulatory Challenges

<table>
<thead>
<tr>
<th>Bodies responsible for regulating unconventional resource development. Do they differ from conventional gas?</th>
<th>New Brunswick</th>
<th>New York</th>
<th>Saskatchewan</th>
</tr>
</thead>
</table>
| • Department of Natural Resources  
• Department of Environment  
• Department of Transportation - trucking  
• WorkSafe NB  
NOTE: NB announced its Comprehensive Natural Gas Development Plan on April 7, 2011, lead by a Natural Gas Steering Committee consisting of Ministers of Environment, Natural Resources, and Energy, Deputy Ministers (DM) of each department, and the DM of Executive Council. The Development Plan deliverables include:  
1) Stakeholder engagement plan  
2) Environmental, Health and Safety Protection Plan  
3) Economic Benefits Plan  
4) Resource Development Plan  
5) Community Development Approach  
6) Regulatory Framework  
Department of Environmental Conservation (NYSDEC), Division of Mineral Resources, regulates the drilling, operation, and plugging of oil and natural gas wells under the Environmental Conservation Law (ECL). Responsible for:  
• managing protection and balanced utilization of natural resources;  
• preventing and abating water, land and air pollution;  
• regulation of storage, handling and transport of solids, liquids and gases to prevent pollution.  
• required by Article 23 of the ECL to prevent waste of State’s oil and gas resources,  
• to provide for greater recovery of resources,  
• and to protect correlative rights.  
NYSDEC, Division of Water, is mandated to protect, manage, and conserve groundwater and surface water supply sources, responsible for:  
• development of management strategies to enhance and protect water,  
• protection of the groundwater and surface water quality in major watersheds.  
Ministry of Energy and Resources Petroleum & Natural Gas Division regulates oil and gas activities. Its mandate is:  
• ensure full & responsible development of oil & gas resources.  
SK Watershed Authority responsible for surface water and ground water, including:  
• approving and licensing water use projects for domestic, municipal (source water only), agricultural, industrial, recreation and wildlife purposes.  
• approving construction and operation of water works  
Dept of Environment regulates through an EIA process. Development projects are screened, especially in sensitive and undeveloped areas. | Required to file Organizational Report (Form 85-15-012) with Division of Mineral Resources containing:  
• Regulations apply to all oil and gas activities.  
NOTE: SK has no commercial discoveries of shale gas |
<table>
<thead>
<tr>
<th>Approval Process for Unconventional Resource Development Projects Involving Hydraulic Fracturing Operations</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Well licence approvals</td>
</tr>
<tr>
<td>• Abandonment plan approvals</td>
</tr>
<tr>
<td>• Suspend and resume drilling approvals</td>
</tr>
<tr>
<td>• Well reconditioning approvals</td>
</tr>
<tr>
<td>• Well licence amendments</td>
</tr>
<tr>
<td>Department of Environment</td>
</tr>
<tr>
<td>• Construct and operate approvals which require:</td>
</tr>
<tr>
<td>• Chemical &amp; Waste Management Plan;</td>
</tr>
<tr>
<td>• Water Management Plan;</td>
</tr>
<tr>
<td>• Containment Systems Plan;</td>
</tr>
<tr>
<td>• Private Well Water Sampling and Analysis Program;</td>
</tr>
<tr>
<td>• Rehabilitation Plan;</td>
</tr>
<tr>
<td>• Background and Operational Noise Assessment Program; and</td>
</tr>
<tr>
<td>• Quarterly Reporting.</td>
</tr>
<tr>
<td>• Other conditions in the approval deal with emissions from the site, site runoff, complaint notification, spills, and environmental emergency situations.</td>
</tr>
<tr>
<td>• Containment system plan approvals</td>
</tr>
<tr>
<td>• Waste management plan approvals</td>
</tr>
<tr>
<td>• Site rehabilitation plan approvals</td>
</tr>
<tr>
<td>• Phased environmental impact assessment registrations</td>
</tr>
<tr>
<td>• Wetland and watercourse alteration permits required for</td>
</tr>
<tr>
<td>• Activities within 30 m of a watercourse or wetland;</td>
</tr>
<tr>
<td>• Zoning requirements under Community Planning</td>
</tr>
<tr>
<td>• Identification of responsible parties and their contact information, financial security.</td>
</tr>
<tr>
<td>Application for a Permit to Drill, Deepen, Plug Back or Convert a Well, accompanied by:</td>
</tr>
<tr>
<td>1) Drilling program, including casing, cementing, completion, testing and stimulation procedures</td>
</tr>
<tr>
<td>2) A plat,</td>
</tr>
<tr>
<td>3) Fee, and</td>
</tr>
<tr>
<td>4) Environmental Assessment Form (EAF).</td>
</tr>
<tr>
<td>• Section A: description of the physical setting of project including well site, pits, access road and staging area, the slope, soil type, vegetation), current land use and size of each areas to be disturbed.</td>
</tr>
<tr>
<td>• Section B description of well site and access road construction procedures, developing the well, identification of water supply for drilling, how long rig will be on site, waste containment and disposal and site reclamation plans.</td>
</tr>
</tbody>
</table>

NOTE: 2011 SGEIS addresses proposed changes to the well-permitting process high-volume hydraulic projects including: |

- No high-volume hydraulic fracturing (HVHF) in New York City and Syracuse Watersheds, on primary aquifers, on certain state lands, on principal aquifers without site-specific environmental review, within 2,000’ of Public Drinking Water Supplies, in floodplains or within 500’ of private water wells, |
- Mandatory disclosure of additives and alternatives to date. |
- SK is an oil prone province, with a history of hydraulic fracturing, mostly relating to oil – to date over 35,000 wells have been hydraulically fractured, including horizontal wells. |
- No new regulations have been introduced to deal with shale gas, unconventional resources or hydraulic fracturing.
<table>
<thead>
<tr>
<th>Act</th>
<th>WorkSafe NB</th>
</tr>
</thead>
<tbody>
<tr>
<td>• blasting certification</td>
<td>NOTE: A phased EIA allows a company to apply separately for each phase of a well’s life cycle.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>analysis (currently require all additives, but no current requirements for alternatives)</th>
</tr>
</thead>
<tbody>
<tr>
<td>•</td>
<td>Enhanced well casing</td>
</tr>
<tr>
<td>•</td>
<td>secondary containment &amp; stormwater controls</td>
</tr>
<tr>
<td>•</td>
<td>disposal of wastewater &amp; solid waste</td>
</tr>
<tr>
<td>•</td>
<td>Air quality control &amp; mitigation of greenhouse gas emissions</td>
</tr>
<tr>
<td>•</td>
<td>Mitigation for loss of habitat and impacts on wildlife</td>
</tr>
<tr>
<td>•</td>
<td>requirement for a transportation plan,</td>
</tr>
<tr>
<td>•</td>
<td>fully cemented intermediate casing &amp; pressure testing,</td>
</tr>
<tr>
<td>•</td>
<td>covered watertight tanks with secondary containment,</td>
</tr>
<tr>
<td>•</td>
<td>consultation with local governments.</td>
</tr>
</tbody>
</table>

Site specific EA is required when:

1) HVHF of a target zone shallower than 2,000’;
2) HVHF of a target zone less than 1,000’ below a known fresh water supply;
3) well pad within 500’ of the boundaries of a principal aquifer;
4) well pad within 150’ of a perennial or intermittent stream, storm drain, lake or pond;
5) surface water withdrawal not consistent with the Department’s passby flow methodology;
6) well location within 1,000’ of its subsurface water supply infrastructure, determined by New York City Department of Environmental Protection (NYCDEP) to be within 1,000’ of its subsurface water supply infrastructure.
<table>
<thead>
<tr>
<th>Are unconventional resource development approvals for individual wells? Do you require a separate application for schemes or projects?</th>
</tr>
</thead>
</table>
| • All wells require approvals.  
  • NOTE: EIA expected to eventually become scheme based.  
  • No real distinction between conventional and unconventional, much of NB geology is tight sand which is necessary in these reservoirs.  
| • Permits are required for each well – because of speculative nature of future drilling plans.  
| • Minister’s order required for horizontal wells at licensing stage.  
| • Applications approved on individual well basis, also have approvals for EOR projects and water-flood projects for groups of wells. |

<table>
<thead>
<tr>
<th>What have been the most important challenges presented by unconventional resource development? How have you addressed these?</th>
</tr>
</thead>
</table>
| • Myriad of studies and proposed standards are underway.  
  • Water is the most important issue.  
  • Proper handling of chemicals.  
  • Casing and well construction standards.  
  • Air issues.  
  • Trucking - Greenhouse gases.  
  • VOCs coming off well at wellhead.  
  • NOTE: Identified need to minimize escape of gases needs to be addressed in the Environmental Protection Plan (EPP). |
| • Preparing the SGEIS while administering existing program.  
| • Shale gas production potentially challenging, no commercial discoveries. Shale is softer and may not be receptive to hydraulic fracturing because of pliability of clays. Challenge finding technologies that work makes SK a less attractive jurisdiction in the short-term.  
| • Split rights challenges – mineral rights with different owners in vertically adjacent formations, especially with formations close together and thin zones. Fracturing in one formation could propagate into adjacent/subjacent formations. Reservoir analysis important. Microseismic used to verify fracturing occurred in correct formations. |

<table>
<thead>
<tr>
<th>What communication tools are used, and by whom, to educate the public about hydraulic fracturing and the</th>
</tr>
</thead>
</table>
| • Public meetings and presentations  
  • Consulted with municipal councils.  
  • A new website developed with an interactive component.  
| • Publication of SGEIS document.  
| • Hearing across state.  
| • Making website downloads user-friendly.  
| • Participant in New West Partnership which is addressing water use.  
| • Participant in FracFocus website development. |
### Table B-2: Drilling and Completion Operations: Casing and Cementing

<table>
<thead>
<tr>
<th>Depth of casing</th>
<th>New Brunswick</th>
<th>New York</th>
<th>Saskatchewan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Draft Gen Reg requires casing be the lesser of 10% of total depth, 10% of depth of intermediate casing point, or 25 m below consolidated sand and gravel. <strong>NOTE:</strong> Maximum depth potable water is ~200 m. Recent gas wells have been cased to 250 to 280 m depth. NB has adopted AB Directive 8, in practise, which has a formula based on depth and pressures, resulting in deeper minimum casing.</td>
<td>Established subsurface formations and pressures by prior drilling experience, option of either running surface casing below deepest potable fresh water level or cementing production casing below deepest potable fresh water level back to the surface. <strong>Unknown subsurface formations and pressures,</strong> surface casing shall extend below deepest potable fresh water level.</td>
<td>Minimum requirements: meet API specifications unless otherwise approved by Minister, minimum depth of: (i)20 m below base of glacial drift; (ii)10% of projected total depth of well; or (iii)75 m; cemented in place by pump and plug method or by displacement method, with sufficient cement to circulate to top of hole; and cement must set under pressure for minimum 8 hours before plug is drilled.</td>
<td></td>
</tr>
</tbody>
</table>

| Regulations for next string of casing (how many strings—is casing done right up to the surface)? | No general requirement for intermediate casing. Specific geological formation may require use of 2nd string (intermediate) casing. Eg, intermediate casing through the salt zones. Casing design approved through application process. Horizontal wells may use production liner rather than production casing to surface. | Minimum 3 strings of cemented casing for fracturing operations. The requirement for intermediate casing can be waived. Outer string (ie, surface casing) extends below fresh ground water and cemented to surface before well is drilled deeper. Intermediate casing string (ie, protective string) is installed between surface and production strings. Innermost casing string (ie, production casing) extends from ground surface to toe of horizontal well. | Require surface casing and production casing. No regulatory requirement for intermediate casing. Additional strings at discretion of operator. Production casing goes to surface but not necessary to cement to surface. Production Casing cemented 50 m above shallowest porous zone. |
| Do parameters exist for quality of cement? | Cementing information required in application.  
- Cementing weight and quality are included in daily drilling report.  
- Samples required to ensure quality. | NOTE: 2011 SGEIS proposes radial cement bond evaluation log or other evaluation approved by NYSDEC to verify cement bond on intermediate and production casing. Quality and effectiveness of cement would be evaluated as per API Guidance Document HF1. Remedial cementing required if cement bond is not adequate to drill ahead and isolate hydraulic fracturing operations. Pressure test may be required if log shows an inadequate cement job. | No cement bond log (CBL) required for hydraulic fracturing  
- Injection wells or enhanced oil recovery (EOR) projects require CBL.  
- May approve special cementing practices when problems encountered in drilling. |
| Techniques to confirm integrity of the cementing and casing (ie, cement bond logging & pressure testing)? | Logging required if no cement returns at the surface.  
- No requirement for leak-off test  
- Leak off test is common industry practice. | NOTE: 2011 SGEIS proposes the following additional requirements for HVHF:  
- Intermediate casing cemented to surface by pump and plug method with either min. 25% excess cement or 10% excess if caliper logs run;  
- Production casing cemented to intermediate casing with at least 300’ of cement measured using True Vertical Depth (TVD). If intermediate casing waived by Department, the production casing must be cemented to surface;  
- Must meet API Specification 10A, cement slurry prepared to minimize free water content and contain gas-block additive;  
- 8 hour minimum WOC time before casing is disturbed in any way, including installation of blow-out preventer (BOP). Operator may request a waiver from required WOC time if actual cement blended with mix water from job source has bench tested to show 8 hours is not required to reach strength of 500 psig; | Production casing required to be cemented by pump and plug, displacement or any other approved method.  
- Cement must set for min. 24 hours and tested by pressure method before plug is drilled or well is perforated. |
Radial cement bond evaluation log or other approved evaluation to verify the cement bond on intermediate and production casing.
Remedial cementing required if cement bond not adequate to drill ahead and isolate hydraulic fracturing operations; and
7 day minimum wait after primary cementing completed before internal pressure test of production string.

Table B-3: Testing of Water and Water Wells

<table>
<thead>
<tr>
<th>Is baseline groundwater testing required?</th>
<th>New Brunswick</th>
<th>New York</th>
<th>Saskatchewan</th>
</tr>
</thead>
<tbody>
<tr>
<td>What is the radius required for baseline testing</td>
<td>As of the June 23, 2011 announcement, EIA minimum requirements: • baseline testing on potable water wells within 200 m of seismic testing; and • baseline testing of potable water wells within 500 m of oil or gas drilling. • Security bond to protect property owners from industrial accidents, including the loss of/or contamination of drinking water, burden of proof on industry.</td>
<td>• Not currently a requirement. NOTE: Many operators do baseline groundwater testing. 2011 SGEIS proposes mandatory testing. • At operator’s expense to test residential water wells within 1,000’ of well pad, subject to well owner’s permission, or within 2,000’ of the well pad if no wells available within 1,000’ (either because there are none or because well owner denies permission). • NYSDEC require results of test be provided to well owner within 30 days of receipt of laboratory results. • Data available to NYSDEC and local health department upon request.</td>
<td>• Not required by Dept of Energy and Resources.</td>
</tr>
<tr>
<td>What chemical parameters are tested for in the project registration</td>
<td>NOTE: A list of standards for seismic and drilling testing is being prepared, and will be provided upon project registration.</td>
<td>• No current requirements. NOTE: 2011 SGEIS proposes the following parameters: Barium, pH, Chloride, Sodium, Conductivity, Total</td>
<td></td>
</tr>
<tr>
<td>question</td>
<td>answer</td>
<td></td>
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<td>--------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------</td>
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<td></td>
</tr>
<tr>
<td>How are the minimum standards determined? What are the minimum standards for water testing i.e. chemicals, metals, anions?</td>
<td>NOTE: standard currently under development.</td>
<td></td>
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</tr>
<tr>
<td>Is a public complaint process in place?</td>
<td>• Complaints received are investigated. NOTE: NB is developing a protocol to address and log water-related complaints. Questions/ Complaints may be submitted through natural gas website email or phone.</td>
<td></td>
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</tr>
<tr>
<td>• Yes, County Health departments investigate complaints within 2,000’ or the radius where baseline sampling occurred, or within a year of last hydraulic fracturing at site. NOTE: The proposed program will pivot on baseline testing. If problems are caused by oil and gas, they will be referred to Oil &amp; Gas Division.</td>
<td>• No formal process exists; investigated as issues arise.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Post-operation monitoring—how long is monitoring done for? Is monitoring required throughout the drilling process?</td>
<td>• Require air quality monitoring, groundwater and surface water. • Water wells must be sampled prior to and subsequent to drilling. Post-sampling completed between 30-60 days of drilling or hydraulic fracturing activity. If more than 90 day interval from drilling to fracturing, additional sampling required. NOTE: Need to consider water quantity as well as quality. Environmental Protection Plan may require onsite dedicated monitoring wells.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• 2011 SGEIS proposes water testing. Propose pre-drilling and post-drilling or hydraulic fracturing testing at established intervals for up to 1 year (proposed 3 months, 6 months and 1 year).</td>
<td>• No monitoring required.</td>
<td></td>
<td></td>
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</tbody>
</table>
Table B-4: Hydraulic Fracturing and Injection Fluids

<table>
<thead>
<tr>
<th>Control Wells for Shale Gas Production?</th>
<th>New Brunswick</th>
<th>New York</th>
<th>Saskatchewan</th>
</tr>
</thead>
<tbody>
<tr>
<td>No requirement.</td>
<td>No.</td>
<td>No.</td>
<td>No.</td>
</tr>
</tbody>
</table>

Requirements for the fracturing (well injection) process?
- Rely on draft General Regulations, along with adoption of certain Guidelines from Alberta.
- Information submitted as part of phased EIA. Phased EIA (based on need for industrial permit from Dept of Environment) deals with storage and handling of fluids, noise, air emissions. Fracturing may be addressed in subsequent EIA phase.
- Application must include casing and cementing plan.
- Potential to energize geological faults is a concern which may get addressed.
- No separate approval required as hydraulic fracturing considered a completion technique.
- Reporting of when fracturing occurs, intervals and fracturing parameters required as with any other stimulation technique. Flowback volumes measured but not volumes of injection fluids.
- Application must include casing and cementing plan.

Geologic prognosis design required prior to the hydraulic fracturing process?
- No separate approval by DNR for well completion.
- Information required in drilling application, and daily well reports.
- Completion requirements in Gen Reg include blow-out prevention, maximum pressures regarding casing burst.
- Addressed in EIA, may be in separate phase from drilling depending on submission.
- DNR get daily drilling reports.
- NOTE: Proposed pre-frac checklist requires hydraulic fracturing plan, may include modeling of formation and fracturing.
- Proposes fracturing shut down if extending beyond intended zone.

Is there a need to do microseismic testing/tracking?
- No requirement.
- NOTE: Operator may complete to confirm effectiveness of HF operations.
- Shallow fracs (<2000’) or fracs closer than 1000’ to groundwater in depth interval require closer impact assessment and review, may require microseismic.
- Not a requirement to conduct or report.

Volumes of water needed?
- Ranges between 400 m³ and 4000 m³ of water per stage number of stages depends on geology, up to
- NOTE: 2011 SGEIS estimates 2.4 - 7.8 million gallons of water required for a multi-stage hydraulic fracture
- Volumes ~ 10 m³ for vertical gas wells.
- Volumes ~750,000 gallons for tight formations.
| What is the base fluid used for hydraulic fracturing procedures in your jurisdiction? | • Propane used for EOR and may be used for fracturing. Use of Propane avoids large water volumes. Expensive, but converts to gas in reservoir and is recovered as gas, can be recycled.  
• No list of banned base fluids. Diesel not allowed. Slickwater, methanol-water and nitrogen all been used.  
• Predominantly freshwater.  
• Mainly water, some nitrogen, some hydrocarbons, polyemulsions have been used where there are reactive clays in the formation. |  |
| What proppant is used? | • Sand to date.  
• No pressure testing required.  
• Fracture design must be made available for NYSDEC review.  
NOTE: 2011 SGEIS proposes pressure-control procedures and equipment be used, and fracturing equipment be pressure tested before pumping the hydraulic fracturing fluid.  
• None required. | • Silica sand. |
| Is pressure-testing likely to be done prior to the fracking procedure? | • Gen Reg requires pressure testing.  
• No pressure testing required.  
• Fracture design must be made available for NYSDEC review.  
NOTE: 2011 SGEIS proposes pressure-control procedures and equipment be used, and fracturing equipment be pressure tested before pumping the hydraulic fracturing fluid. |  |
| Does your jurisdiction require disclosure of fracturing fluid composition? Is this information publicly available and if yes, how? | • Not currently required.  
NOTE: Objective is to require full disclosure of all fluids and chemicals used. Still working on protocols.  
• Directive requires all frac fluids disclosed to NYSDEC as of July 2008. Trade secrets can be protected. Chemicals identified by name and Chemical Abstract Services (CAS) number.  
• Chemical usage is reviewed by NYSDOH.  
• EAF addendum must disclose all additive products proposed, provide Material Safety Data Sheets (MSDS).  
• NYSDEC will publicly disclose fluid additives and flowback fluids need to be reported to Dept of Energy and Resources for treatment.  
• Voluntary disclosure on FracFocus. No Saskatchewan operators on the FracFocus.ca website to date. To date, there are no plans to mandate disclosure. |  |
their MSDS, subject to confidential business information.
• 2011 SGEIS proposes operators evaluate use of alternative additive products that pose less potential risk to water resources.

### Table B-5: Well Spacing

<table>
<thead>
<tr>
<th>Jurisdictions</th>
<th>New Brunswick</th>
<th>New York</th>
<th>Saskatchewan</th>
</tr>
</thead>
<tbody>
<tr>
<td>How is well spacing regulated?</td>
<td>• Gen Regs allow 1 gas well per section and 1 oil well per quarter section.</td>
<td>• Well spacing established by depth and formation, Special provisions for spacing of wells in shale gas pools.</td>
<td>Standard drainage unit, unless otherwise authorized by the Minister, for oil wells, 1 legal subdivision or 16 hectares, and for gas wells, 1 section or 259 hectares. The minister may make orders establishing of fields, pools, spacing areas or zones; drainage units; set-back distances; target areas; and limiting number and types of wells that may exist in a drainage unit.</td>
</tr>
<tr>
<td>How is it changing with the development of unconventional resources? What criteria are used to determine appropriate spacing?</td>
<td>• Can apply for reduced spacing. • Well spacing based on Alberta standards, including ability to set special spacing units. NOTE: Spacing reduction usually applied for. Expect to be mostly pad-based horizontal wells.</td>
<td>• 3 year limitation on developing wells on single pad. • Variance process allows for exceptions.</td>
<td></td>
</tr>
<tr>
<td>Well set-backs and separation distances</td>
<td>• Wetland and watercourse alteration approvals are required if applicable.</td>
<td>A production well must be a minimum of: • 660’ from any boundary line of the lease, integrated leases or unit; • 1,320’ from any other oil and gas well in the same pool; • 100’ from any inhabited private dwelling house without written consent of the owner; • 150’ from any public building or area which may be used as a place of resort, assembly, education, entertainment, lodging, trade, manufacture, repair,</td>
<td>• No drilling operation permitted within 100 m of: (a) a water body; (b) an occupied dwelling; (c) a public facility; or (d) an urban centre. NOTE: This distance is expected to increase to 150 m with proposed regulatory amendments. • Well spacing based on reservoir considerations. • For non-heavy horizontal wells, setback of 150 m required from other wells.</td>
</tr>
</tbody>
</table>

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storage, traffic or occupancy by the public;
• 75’ to the traveled part of any State, county,
township, or municipal road or any public street,
road or highway;
• 50’ from any public stream, river or other body of
water.
NOTE: 2011 SGEIS proposes minimum 150’ setback
from water bodies.

• Multi-stage hydraulic fracturing of any horizontal
wells within 600 m of an active vertical or horizontal
well is prohibited.
• If multi-stage hydraulic fracturing has commenced
within 600 m of a proposed drilling location, drilling
operations shall not begin at the proposed location
until offsetting downhole stimulation procedures
are completed.
NOTE: Regulations exist to prevent seismic activity in
vicinity of water wells (180 m minimum separation),
but there are no separation distances prescribed to
separate water wells from the drilling activities.

Table B-6: Regulatory requirements related to water use for drilling and hydraulic fracturing

<table>
<thead>
<tr>
<th>Trigger for water withdrawals (does water withdrawal over a certain amount trigger regulatory requirements?)</th>
<th>New Brunswick</th>
<th>New York</th>
<th>Saskatchewan</th>
</tr>
</thead>
<tbody>
<tr>
<td>• &gt;50 m3/day (capacity, not use) triggers a phased EIA process.</td>
<td>• Water withdrawals permit required</td>
<td>• Any surface water use requires a water rights licence from SK Watershed Authority (SWA).</td>
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</tr>
<tr>
<td>• Need to test sustainability of withdrawal and impacts on adjacent users.</td>
<td>• Application must include:</td>
<td>• Data obtained in ground water investigation program may be submitted in a final engineering report within 60 days of conclusion of the program.</td>
<td></td>
</tr>
<tr>
<td>• Intake 30 m from a watercourse or wetland trigger for EIA.</td>
<td>• proof of authorization for project,</td>
<td>• Any plans, information or data filed respecting ground water use with Dept of Energy and Resources available to SWA.</td>
<td></td>
</tr>
<tr>
<td>• No water withdrawal permits or fees currently in place.</td>
<td>• scope of proposed project,</td>
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<td></td>
<td>• map of lands to be acquired.</td>
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<td></td>
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<tr>
<td></td>
<td>• reasons why proposed source was selected,</td>
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<td></td>
<td>• adequacy of supply selected</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>• compensation for any damages to persons or property that will result from acquisition of lands or the execution of proposed project.</td>
<td></td>
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<td></td>
<td>• description of near and long term conservation program.</td>
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<tr>
<td></td>
<td>• New Water Resources statute regulates all water withdrawals over 100,000 gpd. Legislation</td>
<td></td>
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</tr>
<tr>
<td>Question</td>
<td>Answer</td>
<td></td>
<td></td>
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<td>-------------------------------------------------------------------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| What best practices in place for water withdrawal practices? What withdrawal method is generally recommended? Screening requirements in place? | • Surface water is preferred source, including run-off impoundments.  
• Water for hydraulic fracturing often purchased from municipal sources.  
• Wetland and Watercourse Alteration Program requires permit and fee for alterations, structures and pipelines to withdraw water.  
NOTE: New York’s Susquehanna River Basin Commission considered as a model, but nothing finalized.  
• Primarily surface water used.  
• Timing of water withdrawals is important, ie, seasonality.  
• Approval required to impound fresh water, under dam safety.  
NOTE: 2011 SGEIS proposes withdrawal permits include conditions to allow NYSDEC to monitor and enforce water quality and quantity standards such as: passby flow; fish impingement and entrainment protections; protections for aquatic life; reasonable use; water conservation practices; and evaluation of cumulative impacts on other water withdrawals.  
• Groundwater or surface water withdrawal greater than 100,000 gpd must file an annual report. Inter-basin diversions must be reported on same form.                                                                 |
| Are potential impacts on other users of the water considered?           | • Water access is “first come, first served”.  
• This hierarchy of water use is in NB’s Environment Protection Plan, Water Strategy will be released.  
NOTE: Important to establish rate of withdrawal is sustainable.  
• If use not on the list of permitted uses in regulation, it is not approved.  
• Surface water withdrawals subject to Surface Water and Groundwater Quality Standards and Groundwater Effluent Limitations which establishes water quality standards:  
• Prohibition of alteration in flow that would impair a fresh surface water body’s designated best use.  
• Appropriate passby flow determined on a case by case basis.  
• Oil and gas industry accounts for 1% of industrial water use.  
• Oil and gas industry uses mostly surface water.                                                                 |

administered by 3 bodies: NYSDEC Water Division, Susquehanna and Delaware River Basin Commissions (federal commissions, with state representation). River Basin Commissions responsible for allocations in those basins. Withdrawals outside these basins are issued by NYSDEC Water Division.
• Lands encompassing municipal water supply areas not likely to be offered for lease.

| Are potential impacts to the aquatic ecosystem considered? | • Not explicitly regulated. NOTE: Part of the current policy review. Water strategy may consider ecological flow rather than minimum flows. | • NYSDDEC regulates any change, modification or disturbance to a "protected stream". It regulates the use and protection of waters and protects fish and wildlife species. • Reviews applications which have: • potential environmental impacts on aquatic, wetland and terrestrial habitats; • unique and significant habitats; rare, threatened and endangered species habitats; • water quality impacts; • hydrology; • water course and water body integrity. | • No requirement for an aquatic habitat protection permit. Aquatic Habitat Protection Permit required: • for alteration of the bed, bank or boundary of any water body; • to remove or add any material to the bed, bank or boundary of any water body; • to remove vegetation from the bed, bank or boundary or any water body. |
| Are aspects such as percentage of flow and/or regular maintenance flow considered? | • Minimum flow requirements regulated under Wetland and Watercourse Alteration Program. • DFO has oversite in terms of minimal flows. | NOTE: 2011 SGEIS proposes permittees employ the Natural Flow Regime Method to avoid degradation of water quality from withdrawals from high volume hydraulic fracturing. | |

**Table B-7: Flowback Fluids Handling and Disposal**

<table>
<thead>
<tr>
<th>New Brunswick</th>
<th>New York</th>
<th>Saskatchewan</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>What is the on-site storage system of flowback/produced water (such as double-walled tanks?)</strong></td>
<td>• EIA does not allow pits; • enclosed tanks and secondary containment required.</td>
<td>• Currently allow lined pits. NOTE: Proposed 2011 SGEIS program predicated by larger volumes of water. 2011 SGEIS proposes flowback water handled at the well pad be contained in covered watertight steel tanks or covered watertight tanks constructed of another material approved by NYSDEC. NYSDEC</td>
</tr>
</tbody>
</table>
encourages exploration of flowback water reuse technologies.

- Additional proposed mitigation measures:
  1) The EAF Addendum would require information about number of receiving tanks for flowback, individual and total capacity and location on well pad;
  2) Permit conditions for high-volume hydraulic fracturing would include:
     a. Fluids removed if no site activity for more than 45 days;
     b. Fluids removed within 45 days of completing drilling and stimulation operations at last well on pad;
     c. Manned fluid transfer operations from tanks to tanker trucks if tank is not visible to truck operator from truck;
     d. Secondary containment for flowback tanks required; and
     e. Min. two vacuum trucks on standby at wellsite during flowback phase.

(iii) Must have equivalent tankage if facility does not have approved fail-safe shut-down control device.

- Tanks must be have internal corrosion protection and be surrounded by a dike with capacity equal to largest tank or greater capacity the minister may require.

- Earthen pits may be used for salt water on an emergency basis in approved areas, if:
  a. pits are lined with commercially available lining;
  b. pit size does not exceed production requirements;
  c. pits incorporate an approved monitoring system which monitors horizontal and vertical seepage;
  d. pits are used in an emergency only and contents disposed of within 48 hrs; and
  e. pits are maintained to prevent leakage and fenced when dictated by safety considerations, or by surface owner request.

- Other methods of salt water storage subject to approval.

- *Hydraulic Fracturing Fluids and Propping Agents Containment and Disposal Guidelines* state:
  - flowback fluids and sand shall be contained in a tank,
  - tanks receiving flowback fluids and sand from water-based, foam and cross-linked hydrocarbon fluid systems shall be placed 23 m from the wellhead unless otherwise approved,
<table>
<thead>
<tr>
<th>How are the piping (transfer) systems set up? End of Pipe Standards for discharge - ie, do they ship to a third party to treat? If and how are facilities that treat wastewater approved?</th>
<th>Only one operator with central processing facility in NB, at Sussex.</th>
<th>The fluid disposal plan demonstrates pipelines and conveyances constructed of suitable materials. Piping between well pads and storage tanks must be described in fluid disposal plan. maintaned leak-free, regularly inspected, and operated using spill control and stormwater pollution prevention practices. NOTE: Developing approach to regulating and encouraging surface pipelines, because of benefits of removing vehicles from roads. Minister of Energy and Resources approves construction and operation of a waste processing facility.</th>
</tr>
</thead>
<tbody>
<tr>
<td>What monitoring is done for quality and quantity (flow rate and chemical composition)? Long-term monitoring of the storage system?</td>
<td>The receiving company of the water does the testing.</td>
<td>Depends on disposal method. If disposed into publically owned treatment facility, receiving facility needs to know quality of what it is receiving. NOTE: 2011 SGEIS proposes the following ongoing monitoring schedule: Sampling and analysis prior to site disturbance at first well on pad, and prior to drilling</td>
</tr>
</tbody>
</table>
commencement at additional wells on multi-well pads;
- Sampling and analysis 3 months after reaching total measured depth (TMD) if there longer than 3 months between reaching TMD and any other milestone on the well pad that would require sampling and analysis; and
- Sampling and analysis 3 months, 6 months and 1 yr after HF operations at each well on the pad.
- Multi-well pads with continuous drilling and HF activity increased frequency of water well sampling and analysis is proposed as well as a simplified protocol, sampling and analysis occurs at 3 month intervals until 6 months after last well is HF, with final sampling and analysis 1 yr after last well is HF.
- Sampling frequency may be increased or extended beyond 1 yr after last HF in response to complaints or other reasonable cause.

| Techniques used to treat, dispose, and recycle used water | Waste water is being shipped to NS and Que for disposal. NB only has municipal wastewater treatment facilities, not industrial treatment facilities. NOTE: Water treatment/disposal is recognized as a potential “bottleneck” for full-scale development & production in NB. | Under the Federal Clean Water Act, the National Pollutant Discharge Elimination System (NPDES), administered by NYSDEC in NY State known as the State Pollution Discharge Elimination System (SPDES), outlines requirements for discharges to surface waters of the US. NYSDEC is responsible for developing and administering the state’s program for meeting the requirements of NPDES, referred to as the State Pollutant Discharge Elimination System (SPDES).
- SPDES is more stringent than Federal NPDES as it

|  |  | Flowback fluids need to be taken to proper treatment facility and disposal site.
- Facilities report on all fluids processed at that facility. |
also regulates discharges to groundwater.

- Administration of SPDES through issuance of wastewater discharge permits, individual and general permits.
- Individual permits are issued to a single facility in one location possessing unique discharge characteristics.
- General permits are issued to a category of discharges involving:
  - the same or similar types of operations;
  - discharge same types of pollutants;
  - require same effluent limitations or operating conditions;
  - require same or similar monitoring; and
  - do not have a significant impact on the environment, individually or cumulatively, when in conformance with permit provisions.
- Minimum threshold for groundwater discharges is 1,000 gpd for sanitary wastewater.
- Industrial wastewaters have no minimum threshold.
- NYSDOH regulates discharges less than 1,000 gpd of sanitary wastewater.
- NYSDEC issues permits for groundwater discharges for up to 10 yrs
- Permits for discharges to surface waters are issued for a max of 5 yrs.

NOTE: Wastewater may be shipped out of state by truck or rail for treatment (PA) and/or disposal (injection in OH). Use of existing municipal
<table>
<thead>
<tr>
<th>Deep-Well Injection: is this practice used, and how is it regulated?</th>
<th>treatment facilities not expected.</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Not current practice due to geology. NOTE: NB geology is tight, pore space is limited for injection. Concerns exist re induced seismicity from injections.</td>
<td>• 1992 GEIS requires brine disposal wells conduct site-specific SEQRA review. • Flowback and disposal strata water must be fully characterized. • Geotechnical information about the disposal strata’s ability to accept and retain the injected fluid. • EPA UIC (Underwater Injection Control) program approval required prior to applying for SPDES permit for discharge. NOTE: The characterization and SPDES permit application process for disposal wells is similar to that for private treatment facilities. The site-specific permitting process considers the following: • Distance to drinking water supplies or sources, watercourses and wetlands; • Topography, geology, and hydrogeology; • Proposed well construction and operation program; • Water quality of receiving stratum for TDS, chloride, sulfate and metals; • Effluent limits for wastewater, groundwater effluent limits and/or groundwater effluent guidance values; and • Applicability of upgradient and downgradient monitoring wells installed in deepest identified potable water aquifer. NOTE: 2011 SGEIS indicates NY State currently has 6 permitted underground disposal wells, 3 of which are</td>
</tr>
</tbody>
</table>

| 55 |
used to dispose of produced brine from oil and/or gas. These wells are privately owned and approved to inject only their own brine. Amendments to existing UIC and SPDES permits would be required for other operations to use these wells.

<table>
<thead>
<tr>
<th>Are techniques such as secondary containment, berms, tanks with liners used?</th>
<th>• Not regulated. NOTE: Secondary containment is a standard practice. Berms used based on best management practices. Phased EIA is triggered for land clearing, pad development addressed in EIA.</th>
<th>2011 SGEIS proposes centralized flowback impoundments require site-specific environmental assessment and SEQRA determination of significance. Storage tanks have advantages over surface impoundments: • Tanks, initially more expensive, experience fewer operational issues (eg, liner system leakage). • Easier to control odours from tanks than open impoundments. • Precipitation increases volume of liquid needing treatment in surface impoundments. • Tanks can be dismantled and reused.</th>
<th>• Flowback fluids must be contained in tanks, no pits allowed. • Located at least 23 m from well; • Secondary containment required, subject to approval of well pad construction. • Closed loop system, items cannot be stored outside of a lease.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Are storage ponds allowed as an option?</td>
<td>• For fresh water only, not for flowback storage.</td>
<td></td>
<td>• Freshwater only, not allowed for flowback fluids.</td>
</tr>
<tr>
<td>Is baseline soil testing required at the well-site? Requirement for a geomembrane liner for drilling practices?</td>
<td>• No requirements. NOTE: Continuing discussion on liner requirements -- under the entire well pad or only under active areas.</td>
<td>• Not currently required. NOTE: Secondary containment will be required for entire well pad under proposed regulations.</td>
<td>• Not required.</td>
</tr>
<tr>
<td><strong>Table B-8: Environmental Impacts Caused and Public Concerns Associated with Hydraulic Fracturing</strong></td>
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<td>---------------------------------------------------------------</td>
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<tr>
<td><strong>Documented negative environmental occurrences associated with hydraulic fracturing? Mitigation measures to address these occurrences?</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>New Brunswick</strong></td>
<td><strong>New York</strong></td>
<td><strong>Saskatchewan</strong></td>
<td></td>
</tr>
<tr>
<td>• 2004 water loss in wells near Sussex not believed to be result of oil and gas activity. Mining Commissioner is investigating relationship with underground mining and impacts on groundwater.</td>
<td>• No documented cases of negative environmental impacts from hydraulic fracturing.</td>
<td>• One reported instance of a well being drilled that started flowing back during fracturing of a nearby well.</td>
<td></td>
</tr>
<tr>
<td>• Fracturing fluids containing radioactive tracer beads spilled on a well-site. The soil in this incident was successfully remediated.</td>
<td></td>
<td>• Guidelines have been set up for drilling near projects involving hydraulic fracturing. Saskatchewan officials felt that no major environmental concerns have occurred with hydraulic fracturing for over 25 yrs.</td>
<td></td>
</tr>
</tbody>
</table>

| **Negative environmental occurrences associated with conventional well operations in your area?** |
| **New Brunswick** | **New York** | **Saskatchewan** |
| • Chemical spills have to be reported, no minimum threshold. | • Negative impacts have been from improper handling of fluids or improper well construction. | |
| • Small spills have been reported. | • Small number of cases and there are no formal statistics. | |
| • Spills handled by Environment Dept, not DNR. | | |
| • No reports of water being affected. | | |

| **Types of concerns being raised by landowners, communities, and interest groups?** |
| **New Brunswick** | **New York** | **Saskatchewan** |
| • Principal concerns are potential water well contamination. | • Landowners -- ensuring lease protects property environmentally. Landowners are working collectively to develop enhanced model lease to better protect their interests. | • Concern in Bakken area with drilling through aquifer. |
| • Concerns re impacts on rural roads, traffic, land access. | • Communities -- Opposing community visions (eg, industrial vs vacation). Traffic, Public, to help protect and conserve available water supplies. | • Water usage concerns- shortages due to drought, water use in oil and gas puts added pressure on resource. |

| **How are these** |
| **New Brunswick** | **New York** | **Saskatchewan** |
| • Every project registered for EIA requires public | • Local area will be notified. No formal comment | • Develop specific guidelines for an area as required. |
| concerns considered in the regulatory process? Do you require public consultation? At what point in the process? | consultation. | period. GEIS process allows issues to be generically addressed rather than individual process re each development. | For example, specific concerns re Bakken aquifer have led to more stringent conductor pipe and extra surface casing requirements.  
• No public hearing process. |
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</thead>
<tbody>
<tr>
<td>What measures are being implemented to mitigate these concerns? Have you modified approval processes for unconventional resource development to accommodate greater public concern?</td>
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<td></td>
<td></td>
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</tbody>
</table>
• NB is using case studies from other jurisdictions, in absence of NB industry; eg, not allowing pits based on problems seen in other areas.  
• Proposed revenue with municipalities and landowners. |  
• Undertook the SGEIS process. |  
• Regulations flexible enough to allow specific responses to issues as they arise (such as the development of guidelines). |
| What are important environmental issues related to hydraulic fracturing operations in your jurisdiction and how are you |  
• Determine naturally-occurring levels of methane vs what’s caused by industry.  
• NB Environment involved in assessment, use tools such as the Groundwater Chemical Atlas. |  
• Water management -- acquisition, transportation, surface management and injection of fracturing fluids, flowback and disposal fluids.  
• Multi-well pad drilling -- mitigates noise, nuisance, traffic, etc., much longer in duration in unconventional drilling.  
• Good site construction, good wellbore construction. |  
• Handling and treatment of flowback fluids is important issue.  
• Pollution of groundwater aquifers, and the use of large quantities of water. SK requirements ensure hydraulic fracturing does not take place in close proximity to potable groundwater. |
addressing these issues?

Does your jurisdiction have environmental issues related to hydraulic fracturing operations which need future work/research? If yes, what plans do you have?

- Natural Gas Development Framework is being created to address environmental, health and safety issues as well as resource development and community benefits.
- Water Use Strategy will be one of the deliverables from this exercise.

- See 2011 SGEIS.

- No.
- Tight gas in western SK is shallow and in multiple zones. Likely require non-typical fracturing. Formation close to groundwater. Must review what kind of fracturing needed, and what is appropriate at shallow depth (<300 m).

Table B-9: Emergency Response, Site Restoration, Financial Security and Data Collection and Reporting

<table>
<thead>
<tr>
<th></th>
<th>New Brunswick</th>
<th>New York</th>
<th>Saskatchewan</th>
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</thead>
<tbody>
<tr>
<td>Emergency Response Plan in place to help mitigate the risk?</td>
<td>• Emergency response plan is a standard requirement addressed in EIA process and environmental protect plan. NOTE: The ERP looking at mechanisms to fund strengthening fire departments in rural areas.</td>
<td>• Local government must be notified before drilling to establish contact with emergency responder. • 2011 SGEIS proposes supplementary permit conditions for HVHF including minimum of 3 days notice prior to well spud. The ERP, proposed to include the following elements: • Identity of qualified individual with authority to respond to emergencies and implement ERP; • Site name, type, location and operator information; • Emergency contact numbers for the area in which the well site is located; and appropriate Regional Minerals Office, equipment, key personnel, first responders, hospitals, and evacuation plan;</td>
<td>Emergency response plan must be submitted before construction of a new or upgrading an existing upstream facility. The plan must include: (i) criteria to assess an emergency situation; (ii) procedures to mobilize and deploy response personnel and agencies; and (iii) procedures to establish communications and co-ordination</td>
</tr>
</tbody>
</table>
| **What site restoration requirements are in place once the drilling operation is completed?** | **Identification and evaluation of potential release, fire and explosion hazards, including prevention procedures;**  
- Implementation plans for shut down, containment and disposal;  
- Site training, exercises, drills, and meeting logs; and  
- Security measures, including signage, lighting, fencing and supervision.  
  The proposed ERP would require the operator or designate be on site during drilling and/or completion operations including HF. Person shall have current well control certification from an accredited training program. |
| --- | --- |
| **What financial security is required to cover environmental liabilities? How is the amount of security determined?** | **Following abandonment of well, the licensee shall reclaim the well site to standards specified by the Minister.**  
- Remediation of any areas beyond the boundaries of well site or facility site that have been damaged, contaminated or otherwise adversely affected by the operations.  
- Security bond not released until final reclamation is satisfactory.  
- Financial security for well plugging required before the permit issued.  
- Must be maintained for the life of the well.  
- Amount based on depth and type of well and can be determined by completing Financial Security Worksheet.  
- The Orphan Well and Facility Liability Management Program requires a security deposit and an orphan fund levy.  
- Security deposit is collected from companies whose liability is greater than their assets;  
- Security amount is difference between the two. Security deposit prevents an individual, who does not have means, from acquiring oil and gas wells or facilities. |
| - Falls under EIA and being formalized under the Environmental Protection Plan.  
- Replacing soil, re-vegetating the area, restoring wetlands and water courses are all required.  
- Land owner may also have interest in final restoration to be done. |  
- Requirement for partial restoration after wells are drilled.  
- Final reclamation after wells are plugged.  
- Requirements may also be dictated by lease with land owner.  
- Security bond not released until final reclamation is satisfactory.  
- Security bond required to protect from impacts. Burden of proof placed on the industry -- see Gen Reg and Act.  
  NOTE: Current bonding requirements under review for adequacy. The Minister has authority to request additional security, beyond that specified in Gen Reg and Act, but this has not been done in practice.  
- Financial security for well plugging required before the permit issued.  
- Must be maintained for the life of the well.  
- Amount based on depth and type of well and can be determined by completing Financial Security Worksheet.  
- The Orphan Well and Facility Liability Management Program requires a security deposit and an orphan fund levy.  
- Security deposit is collected from companies whose liability is greater than their assets;  
- Security amount is difference between the two. Security deposit prevents an individual, who does not have means, from acquiring oil and gas wells or facilities. |
If company goes bankrupt, security deposit will cover cost of decommissioning and reclaiming the site.

- If security deposit is insufficient to cover the cost of the necessary work, the Orphan Fund Levy will pay shortfall, based on an annual levy on all oil and gas companies operating in SK.

**NOTE:** Amended regulations introduce mandatory licensing of upstream oil and gas facilities in SK to ensure that the most current ownership and liability information is available to support Orphan Well and Facility Liability Management Program. A new facility constructed after the introduction of the amended regulations must submit an application and fee of $500.

<table>
<thead>
<tr>
<th><strong>Different financial security requirements for large vs. small operations? For conventional vs. unconventional operations?</strong></th>
<th>None.</th>
<th>No, other than depth. Emerging issue –liability bond for spills and other on site issues.</th>
<th>No specific requirements for financial security relating to unconventional operations.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Have you modified data submission requirements to accommodate hydraulic fracturing operations?</strong></td>
<td>Data submission requirements under phased EIA, with focus on environmental issues, including fluid use, containment, disposal. DNR requires a completion report, well testing reports and operational reports, equipment used. Fluids used, containment, disposal are required by</td>
<td>Injection fluids will be addressed through FracFocus or in a HF module in date collection scheme, which would also include pre-frac checklist.</td>
<td>Flowback fluids must be reported, quantity and quality. Fracturing must be reported as part of completion process.</td>
</tr>
</tbody>
</table>
| Environment. | Logging information, cuttings, well testing information and completion reports are used by hydrocarbon geologist who analyzes data, and used for determining well spacing, resource conservation. | Flowback fluids reporting is critical.  
More information on propagation of fractures, and impacts on other zones.  
The Ministry is concerned about split rights and the reservoir aspects of correlative rights. |
|---|---|---|
| What do you believe is critical data and how is that data used to effectively manage the development of the resource? | Not treated differently.  
Currently not much in regulations to address—likely change moving forward. | Set by statute.  
Submissions are confidential for 6 months; operator can request confidentiality for up to 2 years.  
Trade secret provisions provide confidentiality for indefinite period. |
| What rules govern the confidentiality of industry-submitted data? Is unconventional resource data handled differently from conventional resource data? | | |
## Tables for Pennsylvania, Ohio and Texas

### Table C-1: Overview of Regulatory Processes and Regulatory Challenges

<table>
<thead>
<tr>
<th>Bodies responsible for regulating unconventional resource development. Do they differ from conventional gas?</th>
<th>Pennsylvania (not interviewed)</th>
<th>Ohio (not interviewed)</th>
<th>Texas (not interviewed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Department of Environmental Protection (DEP), Office of Oil and Gas Management (sometimes known as BOGM) administers oil and gas conservation and environmental programs for exploration, development, recovery of oil and gas:</td>
<td>• The Ohio Department of Natural Resources (ODNR), Division of Oil and Gas Resources Management (DOGRM) regulates oil and gas operations, including brine disposal, solution mining, and underground injection operations.</td>
<td>The Railroad Commission, (RC) Oil and Gas Division, regulates the exploration, production, and transportation of oil and natural gas in Texas. Its statutory role is to:</td>
<td></td>
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<tr>
<td>• develops policy and programs;</td>
<td>• Ohio Environmental Protection Agency (OEPA) regulates pollution of water and air.</td>
<td>(1) prevent waste of State’s natural resources,</td>
<td></td>
</tr>
<tr>
<td>• oil and gas permitting and inspection programs;</td>
<td>• Ohio Department of Health (ODH) regulates radiation. Each agency has broad authority to protect public health and the environment, including development and enforcement of regulations.</td>
<td>(2) protect correlative rights of different interest owners,</td>
<td></td>
</tr>
<tr>
<td>• develops regulation and standards;</td>
<td>NOTE: The agencies communicate on issues of common concern. Program changes are anticipated with future development of the Marcellus and Utica Shales.</td>
<td>(3) prevent pollution, and</td>
<td></td>
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<tr>
<td>• conducts training programs; and</td>
<td></td>
<td>(4) ensure safety with issues such as hydrogen sulfide.</td>
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<tr>
<td>• works with Interstate Oil and Gas Compact Commission and the Technical Advisory Board.</td>
<td>• RC regulates oil field injection and disposal wells under an EPA approved program including:</td>
<td>• Waste management is regulated by permitting pits and land farming, discharges, waste haulers, waste minimization, and hazardous waste management.</td>
<td></td>
</tr>
<tr>
<td>The Department of Conservation &amp; Natural Resources (DCNR) leases state lands for activities:</td>
<td>• permitting, annual reports, and tests.</td>
<td>NOTE: Commission has an abandoned well plugging and abandoned site remediation program through funds provided by industry(fees and taxes).</td>
<td></td>
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<tr>
<td>• developed guidance to ensure extraction is accomplished with minimal impact to human safety and environment.</td>
<td>• fluids injection into either productive reservoirs to enhance recovery or into non-productive reservoirs for disposal.</td>
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<tr>
<td>• DCNR and DEP coordinate natural gas development activities on DCNR managed lands.</td>
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<tr>
<td>• DCNR manages the Pennsylvania Natural Diversity Inventory (PNDI) used in DEP’s permitting process.</td>
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<tr>
<td>Three entities are responsible for protecting water quality &amp; managing water withdrawal: the DEP, the Susquehanna River Basin Commission, and the Delaware River Basin Commission.</td>
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<tr>
<td>• For wells drilled in Susquehanna or Delaware River</td>
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<tr>
<td>overview of application and approval process for unconventional resource development projects involving hydraulic fracturing operations.</td>
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<tr>
<td>Permit from DEP required for drilling or altering a well.</td>
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<tr>
<td>Requirements for bonding, construction, site restoration, operating, plugging, reporting, waste handling and disposal, pollution prevention and control (PPC), erosion and sedimentation control (E&amp;S) and gas storage are outlined in the legislation.</td>
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<tr>
<td>DOGRM issues permits to drill and to plug wells.</td>
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<tr>
<td>Two types of drilling permits: urban and non-urban, with standards for each type of permit.</td>
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<tr>
<td>Well permit application includes review of wells or other potential pathways for contamination of groundwater within the minimum spacing distance for well.</td>
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<tr>
<td>Extends to entire lateral of horizontal wells;</td>
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<tr>
<td>Includes plugging records for plugged wells; and</td>
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<tr>
<td>Casing records for other offset wells.</td>
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<tr>
<td>Additional requirements for urban areas:</td>
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<tr>
<td>Photo imagery and location information for tanks and flow lines; and</td>
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<tr>
<td>Notification of property owners within a 500’ radius around the well.</td>
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<tr>
<td>Pre-permit onsite review, which may be attended by local officials or designees.</td>
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<tr>
<td>NOTE: Issues identified in pre-permit site inspection can be addressed through permit conditions.</td>
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<tr>
<td>Baseline testing of water wells within 300’ required prior to the drilling of an urban well. This requirement can be changed to a greater distance by the chief of DOGRM.</td>
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<tr>
<td>NOTE: Almost all urban wells have special permit</td>
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<tr>
<td>The RC permitting process requires submission of an Application to Drill, Deepen, Re-enter or Plug Back.</td>
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<tr>
<td>16 TAC 3.29 outlines HF Chemical Disclosure requirements.</td>
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</tbody>
</table>
### Are unconventional resource development approvals for individual wells? Do you require a separate application for schemes or projects?

- DEP requires separate permit for stormwater management for a group of wells that will disturb 5 or more acres over life of project.
- “Disturbed area” includes well sites and associated roads, pipelines, and storage areas to be constructed.
- Surface landowner and coal deep-mine operator can file an objection about location of well.
- If DEP’s finds no adverse impacts would result, permit to drill is granted.

### What have been the most important challenges presented by unconventional resource development? How have you addressed these?

- Staffing shortages: lack of adequate number of staff to handle the volume of shale gas development in the state; industry competition for personnel makes hiring and keeping experienced staff difficult.
- Barnett Shale is located in a populated area. Many split rights so landowners received no benefit from development.

### Conditions.
- Deep wells may have special permit conditions.
- Wells in areas where hydrogen sulfide is known to occur have special permit conditions.
- All Class II injection wells have special conditions.
- DOGRM utilizes about 2 dozen special permit conditions for various situations when issuing permits.

NOTE: Urban applications account for ~25% of wells.
What communication tools are used, and by whom, to educate the public about hydraulic fracturing and the issues being raised?

- DOGRM using its website as key means to provide information and educational materials to the public on HF.
- FAQs and educational documents as well as direct links to relevant legislation posted.
- Also started posting MSDS data sheets on its website.
- Ohio also participates in public and stakeholder meetings to answer questions and share information, such as the meetings held with the Ohio Farm Bureau in the summer of 2010.
- DOGRM has a Public Information Officer to address public inquiries and respond to specific requests for information.
- RC educating public through public meetings and website.
- Hydraulic Fracturing Chemical Disclosure Requirements adopted in response to public’s concerns about chemicals used in hydraulic fracturing.
- RC has revised regulations and developed additional requirements to address issues within its authority.

<table>
<thead>
<tr>
<th>Table C-2: Drilling and Completion Operations: Casing and Cementing</th>
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</thead>
<tbody>
<tr>
<td><strong>Depth of casing</strong></td>
</tr>
<tr>
<td>Running and permanently cementing a string or strings of casing in each well drilled through a fresh water bearing strata to a depth and in a manner prescribed by regulation.</td>
</tr>
<tr>
<td>Casing and cementing plan required:</td>
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<tr>
<td>showing how the well will be drilled and completed;</td>
</tr>
<tr>
<td>(1) anticipated depth and thickness of producing formation(s), expected pressures, anticipated fresh groundwater zones and method used to determine depth of the deepest fresh groundwater.</td>
</tr>
<tr>
<td>(2) diameter of borehole.</td>
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<tr>
<td>Proposed casing and cementing plans must be submitted with well permit applications. These are reviewed to ensure protection of Underground Source of Drinking Water (USDW) during well completion and operation.</td>
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<tr>
<td>Casing and cementing requirements can be modified by the field inspector.</td>
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<tr>
<td>Modifications are considered to be conditions of a permit based on real-time information.</td>
</tr>
<tr>
<td>Surface casing must be set at least 50’ below USDWs as shown on Division of Water (DoW) maps.</td>
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<tr>
<td>Cement must set undisturbed until an initial</td>
</tr>
<tr>
<td>The casing depth must be protective of usable-quality water, as determined by RC’s Groundwater Advisory Unit (GAU).</td>
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<tr>
<td>May include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.</td>
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<tr>
<td>If in any field or area where no field rules are in effect or surface casing requirements are not specified in the applicable field rules, a letter from the GAU stating the protection depth is required.</td>
</tr>
<tr>
<td>Regulations for next string of casing (how many strings—is casing done right up to the surface)?</td>
</tr>
<tr>
<td>(3) casing type, new or used casing, depth, diameter, wall thickness and burst pressure rating</td>
</tr>
<tr>
<td>(4) cement type, yield, additives and estimated amount.</td>
</tr>
<tr>
<td>(5) estimated location of centralizers.</td>
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<tr>
<td>(6) proposed borehole conditioning procedures.</td>
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<tr>
<td>(7) alternative methods or materials required by DEP.</td>
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<tr>
<td>• Plan must be onsite for review by DEP.</td>
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<tr>
<td>• A copy of well-specific plan to be provided to DEP upon request for review and approval.</td>
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<tr>
<td>• Revisions to the plan must be documented in the plan and available for review by the DEP.</td>
</tr>
</tbody>
</table>
Drinking Water Act), and provides a base for a blowout preventer or other necessary well control equipment, and

- use of steel production casing with sufficient cement to isolate an oil and gas reservoir during well stimulation and during the productive life of the well.
- at least 25% of proposed total well depth,
- Intermediate and or production casing must be cemented from bottom to 600’ above the well-bore or 600’ above highest productive zone,
- Multi-stage cementing may be done where there are multiple productive zones. Each zone must be cemented to 600’ above productive zone.

| Do parameters exist for quality of cement? | Cement must meet or exceed the ASTM International C 150, Type I, II or III Standard or API Specification 10 when cementing surface casing or coal protective casing. | Cement tickets for each cemented string and a copy of all logs used to evaluate the quality of the cementing must be submitted. | Cementing quality requirements are set out for surface casing, cementing operations, cement quality, compressive strength tests and cementing report requirements. |
| Techniques to confirm integrity of the cementing and casing (ie, cement bond logging & pressure testing)? | A cement job log is required which includes the mix water temperature and pH, type of cement with listing and quantity of additive types, the volume, yield and density in lbs per gallon of the cement and the amount of cement returned to the surface, if any. Cementing procedural information must include a description of the pumping rates, in barrels per minute, pressures, in psi, time, in minutes and sequence of events during the cementing operation. | Any string of casing more than 200’ long shall be pressure tested before drilling the cement plug. The casing at pump pressure (in pounds per square inch) shall be calculated by multiplying the length of the casing string by 0.2. Required maximum test pressure shall not exceed 1,500 psi. If the pressure drops 10% or more from the original test pressure within 30 minutes, the casing shall be condemned until the leak is corrected. All cemented casing shall be steel casing that has been hydrostatically pressure tested with an applied pressure ≥ maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a full length electromagnet, ultrasonic, radiation thickness
gauging, or magnetic particle inspection may be used.

<table>
<thead>
<tr>
<th>Table C-3: Testing of Water and Water Wells</th>
</tr>
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<tbody>
<tr>
<td></td>
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<tr>
<td><strong>Is baseline groundwater testing required?</strong></td>
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<tr>
<td>What is the radius required for baseline testing</td>
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<tr>
<td><strong>What chemical parameters are tested for in the water?</strong></td>
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<td>• NA.</td>
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<tr>
<td><strong>How are the minimum standards determined? What are the minimum standards for water testing i.e. chemicals, metals, anions?</strong></td>
</tr>
<tr>
<td><strong>Is a public</strong></td>
</tr>
</tbody>
</table>

69
| complaint process in place? | - surface owners or water purveyors with a water supply within 1,000’ of proposed well location, including direction and distance to water supply from well location, and  
  - any workable coal seams underlying land upon which well is to be drilled or altered.  
  - Objection may be made to the well location.  
  - Wells may not be drilled within 200’ of any existing building or existing water well without the written consent of the owner.  
  - An operator or owner must immediately conduct an investigation as soon as they are made aware of a potential natural gas migration incident. The operator shall notify the DEP and, in conjunction with the DEP, take measures necessary to ensure public health and safety, if sustained detectable concentrations of combustible gas are:  
    (1) > 1% and < 10% of the L.E.L. (lower explosive limit), in a building or structure.  
    (2) ≥ 25% of the L.E.L. in a water well head space.  
    (3) Detectable in the soils.  
    (4) ≥7 mg/l dissolved methane in water.  
  with the DOGRM.  
  - DOGRM procedures require staff to address all complaints.  
  - A complaint may be received in writing, by e-mail, via phone, or in person. Complaints are logged and tracked in an electronic log. Reports are maintained within the DOGRM Risk Based Data Management System (RBDMS) and/or a hard copy complaint file.  
  - When water samples are collected and analyzed, analytical information is maintained within the DMRM Laboratory Information Management System (LIMS). The LIMS data, along with other data, populates the DMRM RBDMS-Water (RBDMS-W) data management system. The DMRM has an investigation manual for ground water related complaints.  
  - Staff are trained in sample collection techniques and follow a chain-of-custody.  
  - The DOGRM have geologists within the UIC Program and within the Enforcement Program to investigate such complaints.  
  - Objections may be made to the well location.  
  - Wells may not be drilled within 200’ of any existing building or existing water well without the written consent of the owner.  
  - An operator or owner must immediately conduct an investigation as soon as they are made aware of a potential natural gas migration incident. The operator shall notify the DEP and, in conjunction with the DEP, take measures necessary to ensure public health and safety, if sustained detectable concentrations of combustible gas are:  
    (1) > 1% and < 10% of the L.E.L. (lower explosive limit), in a building or structure.  
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  with the DOGRM.  
  - DOGRM procedures require staff to address all complaints.  
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  - When water samples are collected and analyzed, analytical information is maintained within the DMRM Laboratory Information Management System (LIMS). The LIMS data, along with other data, populates the DMRM RBDMS-Water (RBDMS-W) data management system. The DMRM has an investigation manual for ground water related complaints.  
  - Staff are trained in sample collection techniques and follow a chain-of-custody.  
  - The DOGRM have geologists within the UIC Program and within the Enforcement Program to investigate such complaints.  
  | within 24 hours. | within 24 hours. |

<p>| Post-operation monitoring—how long is monitoring done for? Is monitoring required throughout the drilling process? | within 24 hours. | NA |</p>
<table>
<thead>
<tr>
<th>Control Wells for Shale Gas Production?</th>
<th>Pennsylvania (not interviewed)</th>
<th>Ohio (not interviewed)</th>
<th>Texas (not interviewed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Requirements for the fracturing (well injection) process?</td>
<td></td>
<td></td>
<td>NOTE: Texas does not consider HF to be “injection.” ● A completion report required, as per Gas Well Back Pressure Test, Completion or Recompletion Report for gas wells which includes information on fracturing depth interval, amount and kind of material used.</td>
</tr>
<tr>
<td>Geologic prognosis design required prior to the hydraulic fracturing process?</td>
<td></td>
<td></td>
<td>Rules do not require testing/tracking, however, operator is required to maintain control of the well at all times and prohibit pollution of surface or subsurface water. ● Financial incentive to do whatever testing/tracking is required to ensure the economics of well.</td>
</tr>
<tr>
<td>Is there a need to do microseismic testing/tracking?</td>
<td></td>
<td></td>
<td>● Most HF operations are of vertical wells and use relatively low volumes of water. ● Some companies buy water from municipal water plants, especially in urban areas, main source is surface water. ● The Division of Soil and Water Resources in ODNR</td>
</tr>
<tr>
<td>Volumes of water needed?</td>
<td></td>
<td></td>
<td>● The volume of water or other base fluid necessary for HF depends on the targeted formation(s) and the number of stages.</td>
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</tbody>
</table>
requires the registration of water withdrawals that may exceed 100,000 gallons per day.
- If large volume HF occurs in a watershed where a river basin commission or other watershed authority has jurisdiction, a permit may be required by the watershed authority.
- Water Resources Management Decision Support System has been developed within the Great Lakes Watershed, and a water use database has been created to inventory water withdrawals and use.

### What is the base fluid used for hydraulic fracturing procedures in your jurisdiction?

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<tr>
<td><strong>HF of Marcellus wells typically uses “slickwater”, predominantly water, pumped at high pressure, with lesser amounts of sand, with very dilute concentrations of additives and chemicals to stimulate the formation, enhance the return, or “flowback” of the slickwater solution following well stimulation, and increase the production of gas from the reservoir.</strong></td>
<td><strong>Nitrogen-based fracturing solutions are used to stimulate shale gas plays. These “foam fractures” typically require ~25% of the water needed for a slickwater frac. However, foam fractures are effective only in relatively shallow formations.</strong></td>
</tr>
<tr>
<td><strong>Marcellus Formations normally occur at greater depths, increased formation pressure limits the ability of foam-based fracture treatments to effectively fracture the formation and deliver the proppant. For this reason, water-based fracture solutions are more common.</strong></td>
<td><strong>Almost all have been water, either fresh, recycled water, or brackish water. Currently, very few HF treatments are performed using propane or other base fluids.</strong></td>
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### What proppant is

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<tbody>
<tr>
<td></td>
<td><strong>Sand/silica beads.</strong></td>
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<tr>
<td>Question</td>
<td>Answer</td>
</tr>
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<td>-------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Is pressure-testing likely to be done prior to the fracking procedure?</td>
<td>• All casing cemented in any well must be steel casing that has been hydrostatically pressure tested with an applied pressure ≥ maximum pressure to which the pipe will be subjected in the well.</td>
</tr>
</tbody>
</table>
| Does your jurisdiction require disclosure of fracturing fluid composition? Is this information publicly available and if yes, how? | • A well completion report must be submitted to the DEP within 30 days of completion of the well which includes the following information:  
  (i) A descriptive list of chemical additives in stimulation fluid, including any acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor and surfactant.  
  (ii) % by volume of each chemical additive in stimulation fluid.  
  (iii) List of chemicals in the MSDS (Material Safety Data Sheets), by name and chemical abstract service number, corresponding to appropriate chemical additive.  
  (iv) The % by volume of each chemical listed in the MSDS.  
  (v) Total volume of base fluid.  
  (vi) List of water sources used under an approved water management plan and volume of water used from each source.  
  (vii) Total volume of recycled water used.  
  (viii) Rate and pressure used in the well.  
  • MSDS information must be submitted to the DMRM.  
  • DMRM posts MSDS information on its website for public access.  
  • Ohio has not yet dealt with any confidential information.  
  NOTE: should the need arise, Ohio will plan to address this issue by the development of rules and/or a Standard Operating Procedure (SOP).  
  • DMRM has been considering if Chemical Abstract Services (CAS) numbers should be included as a requirement.  
  • As of February 1, 2012, the RC requires a completed form be posted on the Chemical Disclosure Registry on or before submissions of the well completion report for a well on which an HF treatment was conducted, including:  
    (i) operator name;  
    (ii) date of HF treatment;  
    (iii) county in which well is located;  
    (iv) API number for the well;  
    (v) well name and number;  
    (vi) longitude and latitude of wellhead;  
    (vii) total vertical depth of well;  
    (viii) total volume of water used in HF treatment of the well or type and total volume of base fluid used in HF treatment, if something other than water;  
    (ix) each additive used in HF fluid and the trade name, supplier, and a brief descriptor of the intended use or function of each additive in the HF treatment;  
    (x) each chemical ingredient used in HF treatment of well subject to requirements of 29 Code of Federal Regulations §1910.1200(g)(2), as required. |
Specific portions of a stimulation record may designated as confidential proprietary information, and DEP will prevent disclosure of the designated information to the extent permitted under the Right-to-Know Law.

provided by chemical supplier or service company or operator, if operator provides its own chemical ingredients;

(xi) all chemical ingredients intentionally added by operator; and

(xii) actual or max concentration of each chemical ingredient listed under clause (ix), (x), or (xi) of this subparagraph in % by mass.

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<table>
<thead>
<tr>
<th>Table C-5: Well Spacing</th>
<th>Pennsylvania (not interviewed)</th>
<th>Ohio (not interviewed)</th>
<th>Texas (not interviewed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>How is well spacing regulated? How is it changing with the development of unconventional resources? What criteria are used to determine appropriate spacing?</td>
<td>No permit may be issued to drill a new, or reopen a gas well which has been plugged in accordance with Oil and Gas Act, unless proposed gas well is located ≥ 1,000’ from any other well. No permit for a gas well which is intended to be part of a well cluster shall be issued unless the well cluster is located ≥ 2,000’ from nearest well cluster as measured from center of well bore of nearest well, unless permit applicant and owner of workable coal seam consent in writing to spacing well clusters closer than 2,000’. Well location limitations are not applicable between and among wells located within same well cluster.</td>
<td>No oil, gas, or geothermal well shall be drilled nearer than 1,200’ to any well completed in or drilling to the same horizon on the same tract or farm; and No well shall be drilled nearer than 467’ to any property line, lease line, or subdivision line. To prevent waste or to prevent the confiscation of property, the RC may grant exceptions to permit drilling within shorter distances. No point on a horizontal drainhole shall be drilled nearer than 1,200’ (horizontal displacement), or other between-well spacing requirement under applicable rules for the field, to any point along any other horizontal drainhole in another well, or to any other well completed or drilling in the same field on the same lease, pooled unit, or unitized tract.</td>
<td>No oil, gas, or geothermal well shall be drilled nearer than 1,200’ to any well completed in or drilling to the same horizon on the same tract or farm; and No well shall be drilled nearer than 467’ to any property line, lease line, or subdivision line. To prevent waste or to prevent the confiscation of property, the RC may grant exceptions to permit drilling within shorter distances. No point on a horizontal drainhole shall be drilled nearer than 1,200’ (horizontal displacement), or other between-well spacing requirement under applicable rules for the field, to any point along any other horizontal drainhole in another well, or to any other well completed or drilling in the same field on the same lease, pooled unit, or unitized tract.</td>
</tr>
</tbody>
</table>
Well set-backs and separation distances

- No well shall be drilled within:
  - 100’ from any stream, spring or body of water or of any wetlands >1 acre in size, and
  - 200’ from any existing building or existing water well without written consent of owner thereof.

NOTE: Marcellus Shale Advisory Commission recommends increasing setbacks to 500’ for private wells; 1,000’ feet for public water systems; and 300’ from water bodies.

- 467”, or other lease-line spacing requirement under applicable rules for the field, from any property line, lease line, or subdivision line.

- No well shall be drilled nearer than 1,200’ of another well in same horizon or tract, and no well shall be drilled nearer than 467’ to any property line or lease line.

NOTE: The RC may increase or decrease minimum distances in the interest of protecting life and for preventing waste and confiscation of property. An application for exceptions to this rule may be subject to a hearing.

| Table C-6: Regulatory requirements related to water use for drilling and hydraulic fracturing |
|----------------------------------|-------------------------------------------------------------|-------------------------------------------------------------|
| **Pennsylvania (not interviewed)** | **Ohio (not interviewed)** | **Texas (not interviewed)** |
| **Trigger for water withdrawals (does water withdrawal over a certain amount trigger regulatory requirements?)** | **The Water Resources Planning Act requires registration of any water withdrawal >300,000 gallons over a 30 day period.** **The Clean Streams Law limits amount of water that can be withdrawn from streams.** **Water management plans are required identifying where water is withdrawn and the quantity.** **Evaluation of plan considers upstream and downstream impacts, other withdrawals from the water resource, impact on low-flow period, etc. as part of a cumulative impact assessment.** | **Division of Soil and Water Resources in ODNR requires registration of water withdrawals >100,000 gallons per day.** **Permit may be required by a watershed authority if HF occurs in a watershed where a river basin commission or other watershed authority has jurisdiction.** | **Any diversion, impoundment, taking, or use of surface water, or construction for those activities requires a water right from TCEQ (Texas Commission on Environmental Quality).** **A temporary water rights permit is primarily designed for water requirements for short duration projects such as oil or gas well drilling projects. Temporary permits for < 1 year and < 10 acre-feet do not require public notice, and are approved or denied within 30 days. The other types of water rights involve public notice.** **NOTE: Water rights may be with or without a term, on an annual or seasonal basis, or on a temporary or** |
There are certain areas of the state where it may be difficult to find water available on any basis, due to existing permits and specific conditions in stream.

<table>
<thead>
<tr>
<th><strong>What best practices in place for water withdrawal practices? What withdrawal method is generally recommended? Screening requirements in place?</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>• Water Management Plans required since 2008 as a result of development of Marcellus shale, to identify where water would be withdrawn and volumes of withdrawal to ensure water quality standards are maintained and protected.</td>
</tr>
<tr>
<td>• Because large withdrawals of surface water can, individually or cumulatively, impact water quality, DEP must ensure excessive withdrawals do not occur.</td>
</tr>
<tr>
<td>• DEP follows water withdrawal guidance promulgated by Susquehanna River Basin Commission (SRBC) to ensure uniform statewide evaluation.</td>
</tr>
<tr>
<td>• Delaware River Basin Commission (DRBC) evaluates impacts within that river basin, and is in the process of promulgating regulations to address Marcellus shale well drilling within its jurisdiction.</td>
</tr>
<tr>
<td>• Studies are underway by universities attempting to provide for greater use of water impacted by acid mine drainage (AMD) for HF. In addition, Pennsylvania State University is studying groundwater before and after HF operations. Industry has been testing wastewater from hydraulic fracturing flowback to establish a baseline of chemical quality through time.</td>
</tr>
</tbody>
</table>

The Texas Commission on Environmental Quality regulates temporary surface water use permits.
| Are potential impacts on other users of the water considered? | • DOGRM does not evaluate water resources for HF operations.  
• The division does encourage operators to work closely with landowners and local governments. Scale of fracturing operations has not approached that of neighboring states, but it is likely only a matter of time until larger HF operations are used.  
• Within Great Lakes Watershed, a Water Resources Management Decision Support System has been developed. A water use database has been created and study of inventory of water withdrawal and use has been completed.  
• A technical subcommittee has studied an inventory of information on ecological impacts. DOGRM, OEPA, and Ohio Department of Health have initiated discussions on Marcellus drilling, water use, waste management, and infrastructure issues. |
<p>| Are potential impacts to the aquatic ecosystem considered? | • Ohio’s Environmental Protection Agency (OEPA) is in process of developing a new general permit for “Wetland and Stream Impacts at Shale Gas Well Sites.” |
| Are aspects such as percentage of flow and/or regular maintenance flow considered? |  |</p>
<table>
<thead>
<tr>
<th>What is the on-site storage system of flowback/produced water (such as double-walled tanks?)</th>
<th>Pennsylvania (not interviewed)</th>
<th>Ohio (not interviewed)</th>
<th>Texas (not interviewed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>• A plan consistent with the Clean Streams Law must be prepared and implemented for control and disposal of fluids, residual waste and drill cuttings, including tophole water, brines, drilling fluids, additives, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids and drill cuttings from the drilling, alteration, production, plugging or other activity associated with oil and gas wells.</td>
<td>• Use of facilities to treat waste is under review. • Currently, the main way waste is dealt with in Ohio is through deep well injection.</td>
<td>• A person shall not deposit or cause to be deposited into a completion/workover pit any oil field fluids or oil and gas wastes other than spent completion fluids, workover fluid, and materials cleaned out of wellbore of a well being completed or worked over. • A permit to maintain or use a pit will state conditions under which the pit may be operated, including the conditions under which permittee shall be required to dewater, backfill, and compact the pit. • These permits address design and construction of pits and disposal facilities, including requirements relating to pit construction materials, dike design, liner material, liner thickness, procedures for installing liners, schedules for inspecting and/or replacing liners, overflow warning devices, leak detection devices, and fences. NOTE: A permit to maintain or use any lined brine mining pit or any lined pit for storage or disposal of oil field brines, geothermal resource waters, or other mineralized waters contain requirements for liner material, liner thickness, procedures for installing liners, and schedules for inspecting and/or replacing liners.</td>
<td></td>
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</table>

<p>| How are the piping (transfer) systems set up? End of Pipe Standards for | The preferred method of flowback water disposal, prior to April 19, 2011, was through existing DEP approved wastewater treatment plants. • These plants typically do not have the technology | Ohio Environmental Protection Agency (OEPA) regulates discharge of fluid wastes via the National Pollution Discharge Elimination System (NPDES). • OEPA has been approached by municipalities | HF flowback water is not allowed to be discharged to surface water in Texas. |</p>
<table>
<thead>
<tr>
<th>discharge - ie, do they ship to a third party to treat? If and how are facilities that treat wastewater approved?</th>
<th>necessary to remove TDS from the effluent and instead rely on dilution. To address concerns over protecting downstream drinking water supplies, Marcellus Shale drillers have ceased taking wastewater to facilities that do not remove dissolved solids such as bromide.</th>
<th>interested in treating oil and gas wastewater and flowback from HF operations in publicly owned treatment works (POTWs). OEPA is working with Ohio’s Department of Health (ODH) to monitor wastewater for NORM and other constituents which could determine if it is appropriate to send wastewater to POTWs for treatment.</th>
</tr>
</thead>
<tbody>
<tr>
<td>What monitoring is done for quality and quantity (flow rate and chemical composition)? Long-term monitoring of the storage system?</td>
<td>• DEP limits the discharge of TDS from new or expanded facilities that take oil and gas wastewater. • Drinking water standards must be met. • Regulations do not allow new discharges &gt;250 mg/l for chlorides, so drinking water supplies would not be impaired due to oil and gas drilling. NOTE: The process of eliminating TDS will also remove radium. Thus, in addition to reducing contaminants discharged to streams, the new rule will increase use of recycled water, promote development of alternative forms of disposal, and promote use of alternative sources of fracturing fluid.</td>
<td>NA</td>
</tr>
<tr>
<td>Techniques used to treat, dispose, and recycle used water</td>
<td>• A plan consistent with the Clean Streams Law must be prepared and implemented for control and disposal of fluids, residual waste and drill cuttings, including tophole water, brines, drilling fluids,</td>
<td>• Recycling of flowback is not typically done due to the small size of operations and associated transportation costs. • The logistics and timing of water reuse make re-use</td>
</tr>
</tbody>
</table>

RC is responsible for control and disposition of waste and abatement and prevention of pollution of surface and subsurface water from exploration, development, and production of oil or gas.
additives, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids and drill cuttings from the drilling, alteration, production, plugging or other activity associated with oil and gas wells.

- Information pertaining to waste volumes & location of disposal/recycling facilities must be submitted in an Annual Report as part of the operator's annual production & waste report.
- Form 26R: Analysis of Residual Waste Annual Report by the Generator provides the reporting & analytical requirements for generators of HF waste.

difficult. NOTE: DOGRM encourages use of alternate sources of water for HF. Some companies are experimenting with the reuse of produced water which is available in large quantities.

- Includes drilling of injection water source wells which penetrate base of useable quality water, requiring the following:
  - a permit to use a disposal well, drill a disposal well or convert an existing well into a disposal well to dispose of oil and gas waste,
  - a letter from the Texas Natural Resource Conservation Commission stating drilling and using the disposal well and injecting oil and gas waste into the subsurface stratum will not endanger the freshwater strata, and
  - that the formation or stratum to be used for the disposal is not freshwater sand.
- Class II disposal and injection wells regulated by RC, through EPA delegated UIC Program.
- RC's program follows requirements under FSDWA and the SDWA to ensure Texas' surface and subsurface water is protected from pollution or contamination by ensuring:
  - proper completion, operation, and monitoring of oil and gas injection and waste disposal wells.
  - Minimum permitting and operating standards and requirements for mobile and stationary commercial oil and gas waste recycling facilities established by RC.
- Recycling and reuse of water encouraged and if proposed, requires an approval.
- Most produced water in Texas is injected in Class II wells permitted for disposal. Produced water
### Deep-Well Injection: is this practice used, and how is it regulated?

- Deep-well injection is not an option because best geological sites for this activity are currently used for gas storage.
- Exploration is on-going to determine new sites for deep-well injection.
- Deep-well injection is primary method to dispose of waste generated by exploration and production operations.
- Fluid injection is prohibited without a permit.
- ~98% of oil and gas waste is injected into Class II disposal wells.
- DOGRM has primacy for Class II UIC wells.

**NOTE:** There are 170 permitted Class II disposal wells, which are sufficient for current anticipated volumes of waste.

### Are techniques such as secondary containment, berms, tanks with liners used?

- Containment of polluting substances and wastes from drilling, altering, completing, recompleting, servicing and plugging well, including brines, drill cuttings, drilling muds, oils, stimulation fluids, well treatment and servicing fluids, plugging and drilling fluids other than gases is required in a pit, tank or series of pits and tanks.
- Construction and maintenance of the pit, tank or series of pits and tanks shall meet the following

- RC permits include necessary requirements.
- Federal regulations require secondary containment.
**requirements:**

1. **be constructed and maintained with sufficient capacity to contain all polluting substances and wastes used or produced during drilling, altering, completing and plugging well.**
2. **designed, constructed and maintained so ≥ 2’ of freeboard remain at all times**
   - unless the tank is provided with an overflow system to a standby tank or pit with sufficient volume to contain all excess fluid or waste.
   - If an open standby tank is used, ≥ 2’ of freeboard is required.
3. **designed, constructed and maintained to be structurally sound and reasonably protected from unauthorized acts of third parties.**
4. **a pit or tank containing drill cuttings from below casing seat, polluting substances, wastes or fluids (other than tophole water, fresh water and uncontaminated drill cuttings) shall be impermeable and constructed with a synthetic flexible liner with permeability < $1 \times 10^{-7}$ cm/sec and with sufficient strength and thickness to maintain integrity of the liner**
   - **liner shall be designed, constructed and maintained to be physically and chemically compatible with the waste and**
   - **resistant to physical, chemical and other failure during transportation, handling, installation and use;**
   - **adjoining sections of liners shall be sealed**
together to prevent leakage in accordance with the manufacturer’s directions;

• If liner material other than a synthetic flexible liner is to be used, a plan must be submitted to identify the type and thickness of the material, installation procedures and approved by Dept before proceeding.

(ii) Liner sub-base shall be smooth, uniform and free from debris, rock and other material that may puncture, tear, cut or otherwise cause the liner to fail.

• The liner sub-base and sub-grade shall be capable of bearing weight of the material stored without settling that may affect integrity of liner.

• If pit bottom or sides consist of rock, shale or other materials that may cause liner to fail, a sub-base of at least 6” of soil, sand or smooth gravel, or sufficient amount of an equivalent material, shall be installed over the area as the sub-base for the liner.

(iii) pit bottom shall be at least 20” above the seasonal high groundwater table, unless otherwise approved under subsection (b)(ie, pit exists only during dry times of the yr, located above groundwater).

(iv) If a liner loses its integrity, the pit shall be managed to prevent the contents from leaking from the pit. If repair of liner or construction of another temporary pit is not
practical or possible, contents shall be removed and disposed at an approved waste disposal facility or disposed on well site in accordance with regulations.

(v) If liner drops below the 2’ of freeboard, the pit shall be managed to prevent contents from leaking from pit and lined freeboard shall be restored.

| Are storage ponds allowed as an option? | • Centralized impoundments, dam like structures, hold enough water to service multiple wells over an extended period of time. These impoundments can store freshwater, and flowback from HF.  
• Small freshwater impoundments do not require approval under DEP’s dam safety regulations. Marcellus Shale impoundments can hold over 15 million gallons and if wastewater is stored, must be permitted and constructed according to DEP standards.  
• Key standards include:  
  • embankment construction standards, an impervious clay sub-base, 2 impervious 40 mil liners with a leak detection zone between; and  
  • groundwater monitoring wells around the impoundment.  
• Impoundments located where a breach could threaten public safety require a stringent engineering review.  
• Stormwater management program may be required by DEP, including an erosion & sediment control | • Yes, but a permit is required. |
plan, plus obtain an Erosion and Sediment Control General Permit.

- To obtain a permit, operator must agree to notify homeowners within 1,000’ of well.
- *Erosion and Sediment Control Regulations* require a site-specific Erosion and Sediment Control Plan consisting of both drawings and a narrative that identifies BMPs to minimize accelerated erosion and sedimentation before, during and after earth disturbance activities.

<table>
<thead>
<tr>
<th><strong>Is baseline soil testing required at the well-site?</strong></th>
<th><strong>Requirement for a geomembrane liner for drilling practices?</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>No requirement for baseline testing.</td>
<td>Pits/ponds generally authorized by rule; a permit is required for any pit/pond not specifically authorized by rule.</td>
</tr>
<tr>
<td>Pits/ponds generally authorized by rule; a permit is required for any pit/pond not specifically authorized by rule.</td>
<td>For those pits/ponds authorized by rule, eg, a reserve pit, a liner is required if necessary to prevent pollution.</td>
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**Table C-8: Environmental Impacts Caused and Public Concerns Associated with Hydraulic Fracturing**

<table>
<thead>
<tr>
<th><strong>Pennsylvania (not interviewed)</strong></th>
<th><strong>Ohio (not interviewed)</strong></th>
<th><strong>Texas (not interviewed)</strong></th>
</tr>
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</table>
| **Documented negative environmental occurrences associated with hydraulic fracturing? Mitigation measures to** | **In Bainbridge Township, Ohio in December 2007 a house exploded as a result of gas migration due to improper cementing and casing practices.**  
**It is reported that water wells were contaminated and residents had to be evacuated from their homes for a period of time.** | **No documented cases of groundwater pollution from HF.**  
**Have been spills associated with unconventional natural gas development activities.**  
**NOTE: RC has not encountered issues specifically associated with HF or horizontal wells.** |

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| **Address these occurrences?** | • HF began in the 1950s.  
• Most wells drilled and completed today HF operations and most are vertical wells.  
• Estimated 80,000 wells have been fractured in Ohio, state agencies have not identified any instance of groundwater contamination by HF operations. | • Yes, as described in Joint Groundwater Monitoring and Contamination Report, 2010. |
| **Types of concerns being raised by landowners, communities, and interest groups?** | • Traffic, dust, noise, air pollution (TCEQ), water pollution, eminent domain issues, aesthetics, earthquakes. | |
| **How are these concerns considered in the regulatory process? Do you require public consultation? At what point in the process?** | • If water supply impacted (by pollution or diminution), the water supply must be restored or replaced and operator pay for any increased costs of maintaining or operating replacement water supply.  
• Stormwater Management: development, implementation and maintenance of BMPs for earth disturbance activities required to:  
  • minimize potential for accelerated erosion and sedimentation, and  
  • manage post construction stormwater, and  
  • protect, maintain, reclaim and restore water quality and the existing and designated uses of waters | • No public consultation is required by RC regulations or state statutes for a drilling permit.  
• Public notice and consideration is required for disposal wells and commercial recycling or disposal facilities.  
• RC’s regulations address concerns of the public within its jurisdiction.  
• Wells in municipalities may be subject to municipal requirements, including consultation. |
<p>| <strong>What measures</strong> | • DEP recently promulgated new regulations that | • RC has held public meetings and used the |</p>
<table>
<thead>
<tr>
<th>Question</th>
<th>Answer</th>
</tr>
</thead>
</table>
| What are important environmental issues related to hydraulic fracturing operations in your jurisdiction and how are you addressing these issues? | **1.** Air issues are being addressed by TCEQ.  
**2.** RC is addressing issues associated with commercial or large volume disposal wells through its permitting.  
**3.** Water use in drought conditions is a concern, however, RC has no jurisdiction over water use. NOTE: The RC is reviewing its regulations to encourage recycling of flowback fluid, produced water or water sources other than fresh water sources in HF. |
| Does your jurisdiction have environmental issues related to hydraulic fracturing operations? | **1.** Air issues are being addressed by TCEQ.  
**2.** RC is addressing issues associated with commercial or large volume disposal wells through its permitting.  
**3.** Water use in drought conditions is a concern, however, RC has no jurisdiction over water use. NOTE: The RC is reviewing its regulations to encourage recycling of flowback fluid, produced water or water sources other than fresh water sources in HF. |
hydraulic fracturing operations which need future work/research? If yes, what plans do you have?

<table>
<thead>
<tr>
<th>Table C-9: Emergency Response, Site Restoration, Financial Security and Data Collection and Reporting</th>
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<tbody>
<tr>
<td>Emergency Response Plan in place to help mitigate the risk?</td>
</tr>
<tr>
<td>A PPC Plan is required when storing, using or transporting materials including: fuels, chemicals, solvents, pesticides, fertilizers, lime, petrochemicals, wastewater, wash water, core drilling wastewater, cement, sanitary wastes, solid wastes or hazardous materials onto, on or from the project site during earth disturbance activities.</td>
</tr>
<tr>
<td>A PPC Plan identifies an emergency response program, material and waste inventory, spill and leak prevention and response, inspection program, housekeeping program, security and external factors, is developed and implemented at construction site to control potential discharges of pollutants other than sediment into waters of the state, shall be available upon request by DEP or conservation district, shall be designed, implemented, and maintained</td>
</tr>
</tbody>
</table>
to protect waters from discharges of pollutants from accidental spills, releases or other activities,
- must identify and list by common chemical name and trade name, locations, sources and quantities of raw chemical materials, commercial chemical products, manufacturing chemical intermediates, and process wastes managed at installation which have potential for causing environmental degradation or endangerment of public health and safety through accidental releases.
- Requests for confidentiality of this information will be handled in accordance with DEP regulations.
- Material Safety Data Sheet (MSDS) for each material in storage must be attached to the Plan.

| What site restoration requirements are in place once the drilling operation is completed? | Plan required for restoration of the land surface disturbed by drilling operations. | The operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines not actively used in continuing operation of the lease within 120 days after plugging work is completed.
- Within same 120 day period, the operator shall remove tanks, vessels, and related piping, loose junk and trash from site, and contour site to discourage pooling of surface water at or around facility site.
- Operator shall close all pits in accordance with the Water Protection Rule 8. The district director may grant a maximum extension of time of 120 days to remove tanks, vessels and related piping. |
| What financial security is required | A bond is required at $2,500/well for 2 years, or a blanket bond for all wells at $25,000/company for 2 years | Surety Bond
- Required to be executed and filed before operating
- Types and amounts of financial security required are: |
<table>
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<tr>
<th>Years, after which time the bond amount may be adjusted by the Environmental Quality Board (and every 2 years subsequent) to reflect the cost of performing well plugging. <strong>NOTE:</strong> Marcellus Commission (2011) recommended increasing bond amounts from $2,500 to $10,000 for wells, and from $25,000 to $250,000 for blanket bonds</th>
<th><strong>(A)</strong> 1 or more wells may file an individual performance bond, letter of credit, or cash deposit in an amount equal to $2.00/foot of total well depth for each well operated, excluding any well bore included in a well-specific plugging insurance policy.</th>
<th><strong>(B)</strong> 1 or more wells may file a blanket bond, letter of credit, or cash deposit to cover all wells in an amount equal to the sum of the base amount determined by total number of wells operated excluding any well bores and/or permits issued to drill, recomplete, or re-enter wells included in a well-specific plugging insurance policy.</th>
</tr>
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<tr>
<td>or producing from a well and prior to being issued a permit. • New surety bond in event of forfeiture of surety bond. • Establishes owner’s failure to comply with a final non-appealable order or compliance agreement, as a reason for surety bond forfeiture. • Authorizes ability to require an owner, operator, producer, or other person who forfeited a surety bond to post a new surety bond in the amount of $15,000 for a single well, $30,000 for 2 wells, or $50,000 for 3 or more wells. <strong>Liability insurance</strong> • Increases the amount from $300,000 bodily injury coverage and $300,000 property damage to $1 million bodily injury and property damage coverage unless well is located in an urbanized area, in which case liability coverage must be $3 million.</td>
<td><strong>(A)</strong> A person performing multiple operations shall be required to file only 1 blanket bond, letter of credit, or cash deposit unless the person is operating a commercial facility. <strong>(B)</strong> The financial security amount shall be the base amount determined by the total number of wells operated or $25,000, whichever is greater. <strong>(C)</strong> After excluding any well bores and/or permits issued to drill, recomplete or re-enter wells included in a well-specific plugging insurance policy, the base amount is determined as follows: (i) The base amount for a person operating 10 or fewer wells or performs other operations shall be $25,000. (ii) The base amount for a person operating &gt;10 but &lt;100 wells shall be $50,000. (iii) The base amount for a person operating ≥ 100</td>
<td></td>
</tr>
</tbody>
</table>
Do financial security requirements differ for large vs. small operations? For conventional vs. unconventional operations?

| Financial security requirements generally tied to the magnitude of operator's activity. |
| No difference in financial security requirements for conventional vs unconventional. |

Have you modified data submission requirements to accommodate hydraulic fracturing operations?

| All permit application information is carefully reviewed before issuing a permit. |
| All required reports are reviewed to ensure compliance with regulations and permit conditions. |
| RC has implemented online permitting and reporting. |
| These programs include many automatic checks to ensure compliance. |

What do you believe is critical data and how is that data used to effectively manage the development of the resource?

| In general, all information is public information with |
| the confidentiality of industry-submitted data? Is unconventional resource data handled differently from conventional resource data? | few exceptions for certain geological or well log information and Trade Secrets.  
- RC does not require the filing of confidential information.  
- In the few cases it is necessary, the RC is required to maintain the confidentiality of the information. |
Attachment 1: Web links to legislation, regulations, and/or guidelines relevant to unconventional resource development

Alberta

The ERCB website provides links to legislation and the various Directives regulating oil and gas activities in Alberta:
(http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_308_265_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/publications_catalogue/publications_available/).


Key relevant legislation in Alberta is

- *Energy Resources Conservation Act* (http://www.ercb.ca/docs/requirements/actsregs/erc_act.pdf), giving powers to the ERCB,

- *Oil and Gas Conservation Act* (http://www.ercb.ca/docs/requirements/actsregs/ogc_act.pdf) and regulations (http://www.ercb.ca/docs/requirements/actsregs/ogc_reg_151_71_ogcr.pdf) governing oil and gas operations.

The *Oil and Gas Conservation Act* is complemented by over 50 Directives (http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_308_265_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/industry_zone/rules_regulations_requirements/directives/) issued by the ERCB which address specific operational issues and approval requirements in a very detailed manner and carry the force of law.


**Directive 8: Surface Casing Depth Requirements** (Dec.14, 2010, http://www.ercb.ca/docs/documents/directives/directive008.pdf) provides a Surface Casing Depth Calculation form to determine the required surface casing depth and any applicable reductions or adjustments. The surface casing depth requirement is generally a function of reservoir pressure and TVD, and always at least 25 m deeper than deepest water well within a 200 m radius of the well.

**Directive 9: Casing Cementing Minimum Requirements** (July 1990, http://www.ercb.ca/docs/documents/directives/Directive009.pdf) outlines the ERCB’s cementing requirements for casing, including certain conditions if special cements (foam cement, thermal cement) are used. For surface casing, the intent of the cementing requirements is to protect useable groundwater. Need to meet API specifications.

**Directive 20: Well Abandonment** (June 2010, http://www.ercb.ca/docs/documents/directives/directive020.pdf) details the minimum requirements for abandonments, casing removal, zonal abandonments, and plug backs. The objective is to cover all non-saline groundwater (water with total dissolved solids [TDS] less than 4000 milligrams per litre [mg/l]) and to isolate or cover all porous zones.

**Directive 27: Shallow Fracturing Operations—Restricted Operations** (Aug. 14, 2009, http://www.ercb.ca/docs/documents/directives/Directive027.pdf) protects water wells and shallow aquifers by requiring licensees to not conduct fracturing operations at depths less than 200 m unless they have fully assessed, as a minimum,

- the fracture program design, including proposed pumping rates, volumes, pressures, and fluids,
- a determination of the maximum propagation expected for all fracture treatments to be conducted,
- identification and depth of offset oilfield and water wells within 200 m of the proposed shallow fracturing operations,
- verification of cement integrity through available public data of all oilfield wells within a 200 m radius of the well to be fractured, and
- landholder notification when active water wells are within 200 m of the proposed fracturing operations.

**Directive 35: Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed** (May 8, 2006, http://www.ercb.ca/docs/documents/directives/directive035.pdf). Baseline water well testing is mandatory for drilling a new well or completing or recompleting wells for the purpose of producing coalbed methane (CBM) above the base of groundwater protection (BGWP). The licensee must offer to test any active water wells or observation wells within 600 m of the CBM well, or if there are no such wells within 600 m, the nearest water well or observation well within 800 m. AE&W and the ERCB expect industry to identify those situations where unique geological or topographical conditions or landowner concern warrant testing at greater distances or more than one well in the 600-800 m radius.

**Directive 040: Pressure and Deliverability Testing Oil and Gas Wells** (Aug 2010, http://www.ercb.ca/docs/documents/directives/Directive040.pdf), section 7.1, states that “While requirements for shale gas control wells are in place as referenced above, there are few shale gas control wells established to date, and further elaboration on the testing requirements for these wells is still under development”.


- requires ongoing self-audits on all hydrocarbon wells that have completions above the BGWP, and
- sets trigger of 30 m$^3$ per month for when monthly water production must be reported for hydrocarbon wells with completions above the BGWP; report and analysis may trigger actions.


- Clarifies completion, logging, testing, monitoring, and application requirements for injection and disposal wells.
- Specifies procedures and practices designed to protect the subsurface environment, including all usable groundwater and hydrocarbon-bearing zones.


Directive 56: Energy Development Applications and Schedules (Sept 2011, http://www.ercb.ca/docs/documents/directives/Directive056.pdf) presents the requirements and procedures for filing a licence application to construct or operate any petroleum industry energy development that includes facilities, pipelines, or wells.


- outlines comprehensive regulatory requirements for the handling, treatment, and disposal of upstream oilfield waste, and
- provides a comprehensive overview of oilfield waste characterization and classification, waste manifesting and tracking, oilfield waste management facilities, application requirements for oilfield waste management facilities, waste management and disposal options.

casing), completion, reconditioning, or abandonment of a well must contain complete data on all operations carried out on the well, including fracturing.

**Directive 62: Coalbed Methane Control Well Requirements and Other Matters** (Aug 2010, [http://www.ercb.ca/docs/documents/directives/directive062.pdf](http://www.ercb.ca/docs/documents/directives/directive062.pdf)) sets out requirements for the designation and testing of control wells, which are required for the purpose of collecting pressure, productivity, and gas content information to allow for an understanding of gas resources in coals.


1. Appropriate emergency response plans (ERPs) are in place to respond to incidents that present significant hazards to the public and the environment.
2. An effective level of preparedness to implement ERPs.
3. The capability in terms of trained personnel and equipment to carry out an effective emergency response to incidents.


Relevant legislation under AE&W includes:

**The Environmental Protection and Enhancement Act** ([http://www.qp.alberta.ca/574.cfm?page=E12.cfm&leg_type=Acts&isbncln=9780779735495](http://www.qp.alberta.ca/574.cfm?page=E12.cfm&leg_type=Acts&isbncln=9780779735495)) which is to support and promote the protection, enhancement and wise use of the environment.

- The drilling, construction, operation or reclamation of an oil or gas well is exempt from an environmental impact assessment under the **Environmental Assessment (Mandatory and Exempted Activities) Regulation** ([http://www.qp.alberta.ca/574.cfm?page=1993_111.cfm&leg_type=Regs&isbncln=9780779738137](http://www.qp.alberta.ca/574.cfm?page=1993_111.cfm&leg_type=Regs&isbncln=9780779738137)). Hydraulic fracturing is not subject to an EIA.

access. In effect, it may become an EIA at regional level, and may have a specific focus, such as hydraulic fracturing, in additional to regional focus. Use of RSAs is still in development, and yet to be actually applied in Alberta.

The Water Act
(http://www.qp.alberta.ca/574.cfm?page=w03.cfm&leg_type=Acts&isbncln=9780779733651) which supports and promotes the conservation and management of water, including the wise allocation and use of water, while recognizing
(a) the need to manage and conserve water resources to sustain our environment and to ensure a healthy environment and high quality of life in the present and the future;
(b) the need for Alberta’s economic growth and prosperity;
(c) the need for an integrated approach and comprehensive, flexible administration and management systems based on sound planning, regulatory actions and market forces;
(d) the shared responsibility of all residents of Alberta for the conservation and wise use of water and their role in providing advice with respect to water management planning and decision-making;
(e) the importance of working co-operatively with the governments of other jurisdictions with respect to trans-boundary water management;
(f) the important role of comprehensive and responsive action in administering this Act.

Water (Ministerial) Regulation
(http://www.qp.alberta.ca/574.cfm?page=1998_205.cfm&leg_type=Regs&isbncln=9780779738946) which regulates diversions of water, distinguishing between temporary water permit and permanent permit; 5000 m3 is trigger in Green area, and elsewhere all freshwater (TDS <4000 mg/litre) use requires water diversion approval.

Alberta’s Water for Life (http://www.waterforlife.alberta.ca/) is a high level, strategic document setting out broad goals that policies and regulations respecting water management are intended to achieve.

Guide to Groundwater Authorizations (Mar 2011,
http://environment.gov.ab.ca/info/library/8361.pdf) clarifies the process for applying to divert groundwater, including:
(a) listing administrative and technical requirements that need to be met to obtain authorization to divert groundwater,
(b) directing applicants to a monitoring and reporting system where they can report the results of conditions attached to their authorization,
(c) clarifying the distinction between replacement wells and supplementary wells,
(d) providing water well users with a hotline number to report complaints related to their water wells, and
(e) directing applicants seeking to disturb groundwater for an activity with specific authorization requirements to the appropriate policy.
Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations (April 2006, http://environment.alberta.ca/documents/Standard_for_Baseline_Water-Well_Testing_for_CBM_Apr2006.pdf) provides the standard for testing of these wells, and the licensee must provide test data and analyses to AE&W and the landowner/occupant. Testing requirements according to the standard are water well capacity, water quality data including routine potability, bacteriological analysis, presence and analysis of gas. This program must be carried out under the direction of a professional registered with APEGGA.
British Columbia

Oil and Gas Activities Act (Oct 2010, http://www.bcogc.ca/OGAA/) consolidated the Oil and Gas Commission Act, the Pipeline Act and the Petroleum and Natural Gas Act, providing a "unique to BC" single window permitting and regulating process.

Drilling and Production Regulation (Sept 2010, http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/536427494%20) addresses well permits, well spacing, well operations, well abandonment, well data, safety, pollution prevention and production operations. In particular, it includes sections on fracturing operations, hydraulic isolation, fracturing fluids records, produced water and water source wells.

Oil and Gas Waste Regulation http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/32_254_2005 provides authorization under the Environmental Management Act for air discharges related to drilling operations and for the injection of produced water and returned completion fluids into approved disposal wells.

Environmental Protection and Management Regulation (http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/21404536) contains specific objectives and requirements related to addressing the potential impact of oil and gas development on water resources.


Well Completion, Maintenance and Abandonment Guideline (Oct 2011, http://www.bcogc.ca/document.aspx?documentID=920&type=.pdf) addresses the various operational steps and regulatory requirements related to well servicing activities, including completions, workovers, maintenance and abandonments. In particular, it includes guidance relating to shallow fracturing and fracturing fluids records.


containment, storage and disposal of returned fracture fluids to enhance protection of the environment, wildlife, and groundwater.


Environmental Protection and Management Guidebook (http://www.bcoqc.ca/document.aspx?documentID=927) contains specific guidance related to addressing the potential impact of oil and gas development on water resources.


New Brunswick

New Brunswick has a web site dedicated to shale gas exploration and development that is designed to provide the most information possible to make informed choices on development of a resource that is potentially to the New Brunswick economy (see http://www2.gnb.ca/content/gnb/en/corporate/promo/natural_gas_from_shale.html).

Many different Acts provide safeguards in the oil and gas industry. The key ones, and the departments they fall under, are as follows:

**Department of Natural Resources**
- Oil and Natural Gas Act
- Crown Lands and Forests Act

**Department of Environment**
- Clean Environment Act
- Environmental Impact Assessment Regulation
- Clean Water Act
- Clean Air Act
- Community Planning Act

**Environmental Impact Assessments**
- Projects that must be registered under EIA, SCHEDULE A: UNDERTAKINGS (see http://laws.gnb.ca/en/showdoc/cr/87-83) include “all commercial extraction or processing of a mineral as defined in the Mining Act”. The EIA process is an important regulatory vehicle in New Brunswick, as it allows wide range of questions to be asked regarding the project and the imposition of conditions in the project approval. Requirements can be imposed by conditions in approvals rather than under regulations.
- New Brunswick follows a phased EIA approach (see http://www.gnb.ca/0009/0377/0003/0001/0012-e.pdf)
- EIA Sector Guidance Notes, Additional Information Requirements For Mining and Mineral Extraction Projects, Version 04-07-14 (http://www.gnb.ca/0009/0377/0002/0001/0012-e.pdf) to assist proponents in preparing a submission for projects involving this sector. It should be read in conjunction with the General Information Requirements as outlined in the latest version of the Registration Guide. The items in this Guidance Note are requirements in addition to those outlined in the Registration Guide.
- On June 23, 2011, new requirements were announced for oil and natural gas exploration, development and production (http://www2.gnb.ca/content/gnb/en/news/news_release.2011.06.0703.html):
  - baseline testing on all potable water wells within a minimum distance of 200 m of seismic testing and 500 m of oil or gas drilling before operations begin. These will be minimum requirements and may be increased depending upon the situation;
• full disclosure of all proposed, and actual, contents of all fluids and chemicals used in the hydraulic fracturing process; and
• a security bond to protect property owners from industrial accidents, including the loss of/or contamination of drinking water, that places the burden of proof on industry.

• On Dec 14, 2011, the following principles were announced as the basis for developing an environmental protection plan for shale gas development in NB (http://www2.gnb.ca/content/gnb/en/departments/natural_resources/news/news_release.2011.12.1351.html):
  o monitoring to protect water quality;
  o addressing the need for sustainable water use;
  o protecting public health and safety;
  o protecting communities and the environment;
  o reducing financial risk and protecting landowner rights;
  o addressing potential impacts of geophysical (seismic) activities;
  o taking steps to prevent potential contaminants from escaping the well bore;
  o verifying geological containment outside the well bore;
  o managing wastes and taking steps to prevent potential contaminants from escaping the well pad;
  o addressing air emissions;
  o maintaining an effective regulatory framework; and
  o sharing information.

• Future regulatory development in New Brunswick may take the form of standards rather than prescriptive regulations, and may be imposed as requirements under an EIA rather than by regulations. NB may determine that a new act/regulations would be necessary, if a large-scale industry were to develop.
Saskatchewan

Oil and Gas Conservation Act,
(http://www.qp.gov.sk.ca/documents/English/Statutes/Statutes/O2.pdf), regulates orderly exploration for, and development of, oil and gas and optimized recovery of these resources.

Oil and Gas Conservation Regulations,
(http://www.qp.gov.sk.ca/documents/English/Regulations/Regulations/O2R1.pdf)


Upstream Waste Management Guidelines, SPIGEC 1, Feb 1996

Saskatchewan Watershed Authority Act, (http://www.publications.gov.sk.ca/details.cfm?p=10498) establishes the Watershed Authority and outlines the Authority’s mandate to manage, control and protect the water resources, watersheds and related lands by regulating water development and water use.
New York

Environmental Conservation Law (ECL)-Article 23: Mineral Resources (Article 23 is also referred to as the Oil, Gas, and Solution Mining Law).


State Environmental Quality Review Act (SEQRA) (http://www.dec.ny.gov/permits/357.html) authorizes the use of generic environmental impact statements to assess the environmental impacts of separate actions having generic or common impacts. Drilling and production of separate oil and gas wells, and other wells regulated under the Oil, Gas and Solution Mining Law (ECL 23) have common impacts. After a comprehensive review of all the potential environmental impacts of oil and gas drilling and production in New York, the Department finalized a Generic Environmental Impact Statement and issued SEQRA Findings on the regulatory program in 1992 (1992 GEIS, http://www.dec.ny.gov/energy/45912.html). In 2008, the Department determined that some aspects of current and anticipated application of high-volume hydraulic fracturing, often used in conjunction with horizontal drilling and multi-well pad development, warranted further review in the context of a Supplementary GEIS (2011 SGEIS, http://www.dec.ny.gov/energy/75370.html). This revised draft SGEIS discusses high-volume hydraulic fracturing in great detail and describes the potential significant impacts from this activity as well as measures that would fully or partially mitigate the identified impacts. Specific mitigation measures would be adopted as part of the Department’s Findings Statement in the event high-volume hydraulic fracturing is authorized pursuant to the studies presented herein.

Information on New York’s proposed regulatory approach to well permitting for high-volume hydraulic fracturing is found in the 2011 SGEIS. The SGEIS recently completed its public review process and the Regulations will be updated as a result of the SGEIS. The proposed definition of “high-volume hydraulic fracturing” (HVHF) is “the stimulation of a well using 300,000 gallons or more of water as the base fluid in fracturing fluid”; this is the cut-off for where more substantial impacts from HVHF arise and incremental environmental provisions apply (SGEIS 2011, Glossary, Page 6). NYSDEQ is currently using 80,000 as a cut-off, based on the 1992 GEIS. Note that most Marcellus Shale fracturing jobs are above the 300,000 gal. cut off.

The 2011 SGEIS Appendix 10 provides a comprehensive list of all proposed permit conditions.
**Ohio**

Statues pertaining to hydraulic fracturing are contained in Chapter 1509 of the Ohio Revised Code (ORC). These laws were amended with the passage of SB 165 which became effective on June 30, 2010.

For a list of the regulatory revisions outlined in Senate Bill 165, see the *The Ohio Legislative Service Commission Final Analysis, Sub. S.B. 165* by Eric Vendel. The actual Senate Bill which was adopted as an act is entitled: 128th General Assembly Substitute Senate Bill Number 165.

*Law*

**Title 15, Conservation of Natural Resources,** Ohio Revised Code (ORC), Chapter 1509: DIVISION OF OIL AND GAS RESOURCES MANAGEMENT - OIL AND GAS, [http://codes.ohio.gov/orc/1509](http://codes.ohio.gov/orc/1509)

*Regulations*

Pennsylvania

*Oil and Gas Act* ([http://www.dep.state.pa.us/dep/deputate/minres/oilgas/act223.htm](http://www.dep.state.pa.us/dep/deputate/minres/oilgas/act223.htm)) in order to:

1. Permit the optimal development of the oil and gas resources of Pennsylvania consistent with the protection of the health, safety, environment and property of the citizens of the Commonwealth.
2. Protect the safety of personnel and facilities employed in the exploration, development, storage and production of natural gas or oil or the mining of coal.
3. Protect the safety and property rights of persons residing in areas where such exploration, development, storage or production occurs.
4. Protect the natural resources, environmental rights and values secured by the Pennsylvania Constitution.

*Coal and Gas Resource Coordination Act* ([http://www.dep.state.pa.us/dep/deputate/minres/oilgas/Act214uc.htm](http://www.dep.state.pa.us/dep/deputate/minres/oilgas/Act214uc.htm)), requires coordination of coal mine and gas well operations; authorizes DEP enforcement powers; and provides penalties.

*Oil and Gas Conservation Law* ([http://www.dep.state.pa.us/dep/deputate/minres/oilgas/Act359uc.htm](http://www.dep.state.pa.us/dep/deputate/minres/oilgas/Act359uc.htm)) defines and prohibits waste in the production of oil and gas; protects correlative rights; spacing of well drilling operations; unitization of lands and horizons; prescribes the rights, obligations and duties of owners and operators with respect to the drilling of oil and gas wells; provides for hearings and the procedures to be followed; imposes duties upon the courts.

*Clean Streams Law* ([http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-52060/Act%20394%20of%201937.pdf](http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-52060/Act%20394%20of%201937.pdf)) to protect and enhance the quality of water in the state.

*Air Pollution Control Act* ([http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-52082/Act%20787%20of%201959.pdf](http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-52082/Act%20787%20of%201959.pdf)) provides for the control, abatement, reduction and prevention of the pollution of the air by smokes, dusts, fumes, gases, odors, mists, vapors, pollens and similar matter, or any combination thereof.

*Solid Waste Management Act* ([http://www.elibrary.dep.state.pa.us/dsweb/View/Collection-10700](http://www.elibrary.dep.state.pa.us/dsweb/View/Collection-10700)) providing for the planning and regulation of solid waste storage, collection, transportation, processing, treatment, and disposal.

*The Water Rights Act*, ([http://www.legis.state.pa.us/WU01/LI/LI/US/PDF/1939/0/0365.PDF](http://www.legis.state.pa.us/WU01/LI/LI/US/PDF/1939/0/0365.PDF)), enacted in 1939, provides authority for allocation of water supplies to public water suppliers, who must obtain Water Allocation Permits from DEP to acquire rights to use surface water sources in Pennsylvania. Landowners’ rights to withdraw surface and ground water from sources on their land for their use on that property are subject to common law rules.

*Water Resources Planning Act* ([http://www.pacode.com/secure/data/025/chapter110/chap110toc.html](http://www.pacode.com/secure/data/025/chapter110/chap110toc.html)) establishes the registration, monitoring, recordkeeping and reporting requirements for purposes of obtaining
accurate information for water resources planning. This legislation is for planning purposes only, and does not include any regulations for any agency to allocate water withdrawals or to permit water use. Any water user exceeding 10,000 gallons per day will be required to register with DEP and periodically report their water use.

*Oil and Gas Operator’s Manual, Appendix 1*  
([http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-48236/Appendix1.pdf](http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-48236/Appendix1.pdf)) provides a list of laws applicable to oil and gas exploration and development in Pennsylvania.

**Regulations:**

*Oil and Gas Wells*  
([http://www.pacode.com/secure/data/025/chapter78/chap78toc.html](http://www.pacode.com/secure/data/025/chapter78/chap78toc.html)) specifies procedures and rules for the drilling, alteration, operation and plugging of oil and gas wells, and for the operation of a coal mine in the vicinity of an oil or gas well.

*Wastewater Treatment Requirements*  
([http://www.pacode.com/secure/data/025/chapter95/chap95toc.html](http://www.pacode.com/secure/data/025/chapter95/chap95toc.html)) under the *Clean Streams Law*.

*Erosion and Sediment Control*  
([http://www.pacode.com/secure/data/025/chapter102/chap102toc.html](http://www.pacode.com/secure/data/025/chapter102/chap102toc.html)) requires persons proposing or conducting earth disturbance activities to develop, implement and maintain BMPs to minimize the potential for accelerated erosion and sedimentation and to manage post construction stormwater; the BMPs are to protect, maintain, reclaim and restore water quality and the existing and designated uses of waters.

**Guidelines:**

*Instructions for completing an application for a permit to drill or alter an oil or gas well,*  
([http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-83435/01%205500-PM-OG0001%20Instructions.pdf](http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-83435/01%205500-PM-OG0001%20Instructions.pdf)).

*Oil and Gas Operator's Manual*  
([http://www.governor.state.pa.us/portal/server.pt/directory/oil_and_gas_operator's_manual/142161?DirMode=1](http://www.governor.state.pa.us/portal/server.pt/directory/oil_and_gas_operator's_manual/142161?DirMode=1)) consists of 5 chapters and 5 appendices addressing different aspects of oil and gas operations and regulatory compliance.

*Oil and Gas Wastewater Permitting Manual*  
([http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-48256/550-2100-002.pdf](http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-48256/550-2100-002.pdf)) provides guidance to the oil and gas industry on DEP policies and the process of permitting facilities for the handling, treatment, and disposal of wastewaters from oil and gas drilling and production.

*Guidelines for the Development and Implementation of Environmental Emergency Response Plans*  
([http://www.elibrary.dep.state.pa.us/dsweb/Get/Version-48522/400-2200-001.pdf](http://www.elibrary.dep.state.pa.us/dsweb/Get/Version-48522/400-2200-001.pdf)) are to improve and preserve the purity of the waters by prompt adequate response to all emergencies and accidental spills of polluting substances for the protection of public health, animal and aquatic life and for recreation.

DEP has extensive information on its website. A particularly good source is the *list of fact sheets* related to the Marcellus Shale available, which includes well drilling application forms.
Texas

*Texas Administrative Code (TAC), Title 16, Chapter 3, Oil and Gas Division*,

*Texas Administrative Code (TAC), Title 30, Chapter 297, Water Rights*

*Texas Administrative Code (TAC), Title 30, Chapter 30, Subchapter J, Wastewater Operators and Operations Companies*

Oil and Gas Industry Information: http://www.rrc.state.tx.us/industry/og.php, provides forms and compliance information for oil and gas industry.

Oil and Gas Permit Information: http://www.rrc.state.tx.us/licenses/og/index.php

Texas Commission on Environmental Quality (TCEQ) website provides a current summary of TCEQ regulatory requirements related to oil and gas activity:
Wyoming

Title 30, Mines and Minerals, Chapters 5 and 8 (http://legisweb.state.wy.us/statutes/statutes.aspx?file=titles/Title30/Title30.htm)

Oil and Gas Rules (http://soswy.state.wy.us/Rules/default.aspx), under Title 30, Mines and Minerals, consisting of
- Chapter 1: Authority and Definitions,
- Chapter 2: General Rules,
- Chapter 3: Operational Rules, Drilling Rules,
- Chapter 4: Environmental Rules, Including Underground Injection Control Program Rules for Enhanced Recovery and Disposal Projects, and
- Chapter 5: Rules of Practice and Procedure before the Wyoming Oil and Gas Conservation Committee.

Chapter 3, Section 45 is key authority for regulating hydraulic fracturing --

Environmental Quality Act (http://legisweb.state.wy.us/statutes/titles/title35/t35ch11.htm) stipulates that no person shall
- construct, install, modify or operate any public water supply, sewerage system, treatment works, disposal system or other facility capable of causing or contributing to pollution, without a permit, except for any publicly owned or controlled sewerage system, treatment works, disposal system or public water supply, and
- cause, threaten or allow violation of a surface water quality standard contained herein.

Regulations for Permit to Construct, install or Modify Public Water Supplies, Wastewater Facilities, Disposal Systems, Biosolids Management Facilities, Treated Wastewater Reuse Systems and other Facilities Capable of Causing or Contributing to Pollution (http://deq.state.wy.us/wqd/WQDrules/Chapter_03.pdf) excludes the following facilities being regulated by other agencies of the State of Wyoming, while subject to the requirements of the Wyoming Environmental Quality Act, from requiring a permit:
(i) Noncommercial pits and ponds permitted by the Wyoming Oil and Gas Conservation Commission for the storage, treatment and disposal of drilling fluids, produced waters, emergency overflow wastes or other oil field wastes associated with the maintenance and operation of oil and gas exploration and production wells on a lease, unit or communitized area;
(ii) Noncommercial underground disposal into Class II injection wells, as defined under the federal Safe Drinking Water Act, of salt water, non potable water and oil field wastes related to oil and gas production and permitted by the Wyoming Oil and Gas Conservation Commission.

Guideline for Sampling and Testing Water Well Quality (Dec 2010)
http://deq.state.wy.us/wqd/groundwater/downloads/Water%20Well%20Testing%20Dec%202010%20Final.pdf recommends that all domestic wells be initially sampled and analyzed.

Guideline for Sampling and Testing Water Wells in Areas of Oil and Gas Development (Dec 2010)
http://deq.state.wy.us/wqd/groundwater/downloads/Water%20Well%20Testing%20for%20Oil%20and%20Gas%20Guideline%20Final%20Dec%202010%20Final.pdf was developed in response to concern of water well owners about potential impacts to water wells due to industrial activity, such as oil and gas exploration and development.

Guidelines: Commercial Oilfield Wastewater Disposal Facilities (Rev Feb 2011,
http://deq.state.wy.us/wqd/www/Permitting/Downloads/Produced%20Water/COWDF%20Guidance%20Doc%20Final.pdf) consolidates into one document the DEQ Water Quality Division (WQD) rules and regulations pertaining to the permitting, construction, operation, bonding, and monitoring of
Attachment 2: Questionnaire Template

Nova Scotia Review of Hydraulic Fracturing Practices
Questions for Jurisdictional Review of Regulatory Practices
RESEARCH QUESTIONS RESPECTING XX

About this Study
The Government of Nova Scotia is currently reviewing the practice of hydraulic fracturing for onshore oil and gas exploration. Specifically under review is: the identification of potential environmental issues related to hydraulic fracturing; a study of how these issues are managed in other jurisdictions; and an identification of current best practices for regulatory management.

Nova Scotia has established a Hydraulic Fracturing Review Committee consisting of staff from Nova Scotia’s Department of Energy and Department of Environment. Staff from this committee will work with consultants Paul Precht (Energy Economics Ltd.) and Don Dempster (Wolf Island Engineering) to conduct jurisdictional interviews with 9 regulatory bodies in the United States and Canada. The goal is to learn how other jurisdictions have established regulatory best practices for hydraulic fracturing operations.

What we ask of you:
We would like to thank you for taking the time to participate.

Prior to your follow-up phone call, please take a moment to review the interview questions attached. You will note that we have made efforts to answer questions about your jurisdiction for which we had information. As you review our answers, please ensure we have captured the correct and most up-to-date information for your jurisdiction. The questions are regulatory in nature, with several inquiries on technical details. Questions for which we did not have data and/or thought were best answered directly by your jurisdiction have been left blank.

These questions will be what we review with you during the follow-up phone call.

Confidentiality
The information you provide will be captured in a final report written by our consultants. There will be two reports, one to be released publicly that will include information that is in the public domain, or can be share publicly, and a more detailed report for internal use within the Nova Scotia Departments of Energy and Environment which may include information provided on a confidential basis. The public report will identify the regulatory authorities interviewed and the respective jurisdictions. The internal report will include the names of persons interviewed.
Logistics
The interview questions are listed below, in **bold print**. You are welcome to submit your answers in writing prior to your scheduled interview. If there are follow-up resources, websites, and/or contacts you think would be of use from your jurisdiction, please provide in the space at the end of this questionnaire. If you have questions regarding this document, please contact Paul Precht at (780) 437-7587 (precht@nrgeconomics.com) or Don Dempster at (250)333-8654 (wie@uniserve.com).

**Definition: Unconventional Resource Development**
The term “unconventional resource development” is used throughout these questions. Captured under this term are any unconventional oil and gas development areas (i.e. shale oil and gas, coal bed methane, tight gas, etc.) for which hydraulic fracturing might be used.

**QUESTIONS**

**OVERVIEW OF REGULATORY PROCESS**

1.1 What are the regulatory bodies responsible for regulating unconventional resource development in your jurisdiction? Do they differ from conventional gas? If so, how?

1.2 Could you provide us with web-based links to relevant legislation, regulations, and/or guidelines relevant to unconventional resource development in your jurisdiction? We are particularly interested in aspects relevant to hydraulic fracturing.

1.3 Please provide a brief overview of how the application and approval process for unconventional resource development projects involving hydraulic fracturing operations functions. If and how does this differ from conventional projects?

1.4 Are unconventional resource development applications and approvals accepted for individual wells? Do you require a separate application for schemes or projects?

1.5 Has there been a need to hire additional staff at regulatory bodies in your jurisdiction to respond to unconventional resource development?

1.6 What have been the most important challenges presented by unconventional resource development? How have you addressed these?
DRILLING AND COMPLETION OPERATIONS

2.1 What are your drilling and completion regulatory requirements that are unique to unconventional resource development, particularly for projects which involve hydraulic fracturing? Specifically:

a) What details do you require for the well design, such as the installation, casing, grout and testing program?

b) Depth of casing required?

c) Regulations for next string of casing (how many strings i.e. surface, conductor, production, intermediate—is casing done right up to the surface)?

d) How do you measure the quality of cement?

e) What techniques are in place to confirm the integrity of the cementing and casing (i.e. cement bond logging & pressure testing)?

2.2 Baseline groundwater and surface water testing requirements:

a) Is baseline testing of water wells (drinking water) required?

b) What is the radius required for baseline testing?

c) What chemical parameters are tested for in the water?

d) What are the minimum standards for water testing (e.g., chemicals, metals, anions)

e) Is a public complaint process in place?

f) What monitoring is required throughout the drilling process?
g) Post-operation monitoring—how long is monitoring done for?

2.3 Well-injection (hydraulic fracturing) process:

a) What geologic prognosis design do you require prior to the hydraulic fracturing process?
For instance: depth of overburden, thickness of target geologic formation, depth of targeted geology, hardness of the modulus, location of major geologic faults in proximity to site.

b) Are control wells used for shale gas production?

c) Is there a need to do microseismic testing/tracking?

d) What volumes of water are generally needed for the hydraulic fracturing process?

e) What is the base fluid used for hydraulic fracturing procedures in your jurisdiction (i.e. water, nitrogen, propane, diesel, etc.)?

f) What proppant is used?

g) Is pressure-testing likely to be done prior to hydraulic fracturing?

h) How does your jurisdiction regulate disclosure of fracturing fluid additives and proppants?
Do you make this information publicly available, and if yes, how?

2.4 How is well spacing regulated? How is it changing with the development of unconventional resources? What criteria are used to determine appropriate spacing?

a) Well set-backs and separation distances:

2.5 What are your jurisdiction’s regulatory requirements related to water acquisition for drilling and hydraulic fracturing?
a) Does water withdrawal over a certain amount trigger regulatory requirements?

b) What best practices are in place for water withdrawal practices? What withdrawal method is generally recommended? Screening requirements in place?

c) Are potential impacts on other users of the water considered?

d) Are potential impacts to the aquatic ecosystem considered?

e) Are aspects such as percentage of flow and/or regular maintenance flow considered?

2.6 How does your jurisdiction regulate the handling and storage of produced and flowback waters from hydraulic fracturing operations? Specifically:

a) What is the on-site storage system of flowback/produced water (such as ponds, tanks)?

b) How is the piping (transfer) system set up?

c) What monitoring is done for quality and quantity (flow rate, chemical composition, return rate)?

2.7 How does your jurisdiction regulate the treatment, disposal, and recycling of water used in the hydraulic fracturing process? Specifically:

a) Treatment: end of pipe standards for discharge i.e. is waste water shipped to a third party to treat?

b) If and how are facilities that treat waste water approved in your jurisdiction?

c) Disposal: does your jurisdiction allow deep-well injection? If so, how is this regulated?

d) Recycling: does the reuse of the water treated on site occur?
2.8 Do you have any documented occurrences of negative environmental impacts caused or suspected to have been caused by hydraulically fracturing a new unconventional well? Please explain what mitigation measures are in place to address these occurrences.

2.9 Have there been any environmental impacts associated with conventional well drilling and operations in your area?

2.10 What are your well plugging and well abandonment requirements? Have you had any issues associated with plugging wells that have been subjected to massive hydraulic fracturing or associated with long-reach horizontal wells?

LANDOWNER/PUBLIC CONCERNS

3.1 What are the types of concerns being raised by landowners, communities, and interest groups?

3.2 How are these concerns considered in the regulatory process? Do you require public consultation? At what point in the process? What is required of exploration companies?

3.3 What measures are being implemented to mitigate the concerns being raised? Have you modified any aspects of your approval process for unconventional resource development to accommodate greater public concern?

3.4 What communication tools are used, and by whom, to educate the public about hydraulic fracturing and the issues being raised?

ENVIRONMENTAL ISSUES

4.1 What are considered to be important environmental issues related to hydraulic fracturing operations in your jurisdiction and how are you addressing these issues?

4.2 Does your jurisdiction have any environmental issues related to hydraulic fracturing operations which need future work/research? If yes, what plans you have in this regard?

4.3 How do you protect groundwater and surface water in your jurisdiction? Specifically:
   a) How are the chemicals stored on site?
b) Are techniques such as secondary containment, berms, tanks with liners used?

c) Are storage ponds allowed as an option?

d) Is hydraulic conductivity of the soil considered and how?

e) What setback distances of the drilling site from nearest watercourse are required?

f) Is there a requirement for a geomembrane liner for drilling practices?

g) Is an emergency response plans required to help mitigate the risk?

4.4 What regulations are in place to prevent potential impacts on land (such as soil contamination) as a result of hydraulic fracturing operations? (Note there may be overlap with this question and 4.3)

a) How are the fate and transport of chemicals in the environment monitored?

b) Is baseline soil testing required at the well-site?

4.5 What site restoration requirements are in place once the drilling operation is completed?

FINANCIAL SECURITY

5.1 What financial security is required to cover any potential environmental liabilities? How is the amount of the security determined?

5.2 Are there different financial security requirements in place for large vs. small operations? For conventional vs. unconventional operations?

DATA COLLECTION AND DISSEMINATION

6.1 If you have modified data submission requirements to accommodate hydraulic fracturing operations, please mention below.
6.2 What do you believe is critical data and how do you use that data to effectively manage the development of the resource?

6.3 What are your rules concerning the confidentiality of industry-submitted data? Is confidentiality of unconventional gas data handled differently from that of conventional resource data?

Thank you for completing this questionnaire. We look forward to touching base with you during our scheduled teleconference interview.

Further Resources

If you have any suggested further resources, contacts, and additional information from your jurisdiction that would be of benefit to this study, please suggest in the space below: