Report 2011-A

ERCB

Unconventional Gas Regulatory Framework—Jurisdictional Review

January 28, 2011

Energy Resources Conservation Board

ENERGY RESOURCES CONSERVATION BOARD
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Acknowledgement and Disclaimer

The Energy Resources Conservation Board (ERCB) would like to acknowledge the regulators and stakeholders who contributed to this report. The information provided herein is the ERCB’s summary and interpretation of those contributions. As a result, this report may contain discrepancies and inaccuracies.

1 Introduction

Established in 1938, the Energy Resources Conservation Board (ERCB/Board) has a long history of regulating oil and gas development. The ERCB's vision is "to be the best nonconventional regulator in the world by 2013."

The ERCB's mission reflects its legislative mandate "to ensure that the discovery, development, and delivery of Alberta's energy resources take place in a manner that is fair, responsible, and in the public interest."

As in many producing basins in the world, Alberta's conventional oil and gas production is in decline. Alberta has large reserves and increasing production of bitumen, as well as considerable potential for coalbed methane (CBM), shale gas, and tight gas. Much of the ERCB's current regulatory regime was designed for conventional oil and gas development and did not fully contemplate the unique nature of unconventional gas. As producers shift investment towards unconventional gas development, the ERCB needs to put effective regulation in place to address its development.

In support of its vision and mission, the ERCB has initiated a corporate-wide Unconventional Gas Regulatory Framework Project to develop and implement a new regulatory framework for the development of Alberta's CBM, shale gas, and tight gas by 2011. The project is assessing regulatory risk associated with developing unconventional gas, and it is assessing scientific and technological challenges and opportunities. The first phase of the project included three task teams: Regulatory Risk, Science and Technology, and Jurisdictional Review. This document summarizes the objectives and findings of the Jurisdictional Review Task Team.

The objective of the Jurisdictional Review was to learn how other jurisdictions were regulating unconventional gas development, what issues were encountered, and how these were managed within the regulatory framework. A key component of the ERCB's Jurisdictional Review was a survey of other jurisdictions, most of which have more extensive experience with shale gas development. A written survey that was prepared to collect information from the key oil and gas regulator in each jurisdiction was organized around seven topics drawn from the ERCB's mandate and the preliminary Regulatory Risk Review. These were resource appraisal and reserves, reservoir development, drilling and completion operations, landowner/public concerns, environmental issues, regulatory processes, and information collection and dissemination. (A copy of the survey is attached in Appendix 2.) While not all regulators share completely common mandates or approached issues in the same way, all are responsible for ensuring responsible energy development. The survey was sent to 18 jurisdictions in Canada and the United States, and outside of North America.

This report summarizes the findings of the Jurisdictional Review Task Team and identifies opportunities to be considered for Alberta's unconventional gas regulatory framework. Its primary purpose is for use by the ERCB, but it is also being provided to the jurisdictions that responded to our request for information to recognize their valuable input and to share the findings.

2 Jurisdictions

The following jurisdictions submitted completed written surveys:

- Michigan Department of Natural Resources and Environment—Office of Geological Survey
- Louisiana Department of Natural Resources—Office of Conservation
- Saskatchewan Ministry of Energy and Resources

The following jurisdictions provided input through detailed telephone interviews:

- British Columbia Oil and Gas Commission
- Pennsylvania Department of Environmental Protection—Bureau of Oil and Gas Management
- Oklahoma Corporation Commission
- Railroad Commission of Texas

The New York State Department of Environmental Conservation was unable to participate in the Jurisdictional Review survey, but it did direct the project team to relevant materials, most importantly the draft Supplemental Generic Environmental Impact Statement (SGEIS) for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus Shale (http://www.dec.ny.gov/energy/58440.html).

In addition to seeking input from the key oil and gas regulator in each jurisdiction, the Jurisdictional Review Task Team interviewed eight companies to get industry perspectives on regulatory frameworks in the jurisdictions. Companies were selected on the basis of having either current unconventional gas operations in Alberta or an interest in expanding Alberta shale gas development, and for being engaged in unconventional gas plays outside of Alberta. This survey group provided responses from the perspective of businesses with knowledge of a cross section of regulatory frameworks. Responses included specific suggestions and examples of actions taken in other jurisdictions for consideration in Alberta. The input is summarized in this report.

Input, both written and through the telephone interviews, was given in a very open and comprehensive fashion and provided valuable insight. The Jurisdictional Review Task Team appreciates the input provided. Although the number of responses from regulators was limited, key North American jurisdictions with unconventional gas did respond, and these were sufficient to allow the team to assess the issues, understand the differences and similarities between regulators, and identify potential regulatory opportunities for Alberta unconventional gas development.

In describing regulatory issues and regulators' comments in this report, the Jurisdictional Review Task Team has paraphrased and summarized written survey responses, interpreted verbal discussions with regulatory agency staff, and in some cases supplemented its understanding by reviewing documents on regulatory websites. Any inaccurate comment attributed in this report to a participating agency is unintentional and is the sole responsibility of the Jurisdictional Review Task Team.

3 Shale Gas Development in the Jurisdictions

Shale gas in North America is emerging as a key unconventional resource, and its development is spawning new regulatory issues. To provide context for the reader, the table below identifies the key energy regulatory agency and the major shale gas plays in each jurisdiction.

Locations of shale gas plays are shown on Figure 1. U.S.A. shale gas basin locations were provided by the United States Energy Information Administration. Prospective shale gas areas shown for Alberta and British Columbia are areas of potential activity based on preliminary analysis by Alberta Geological Survey geoscientists. The entire coverage of the shale basins in either province is not shown.

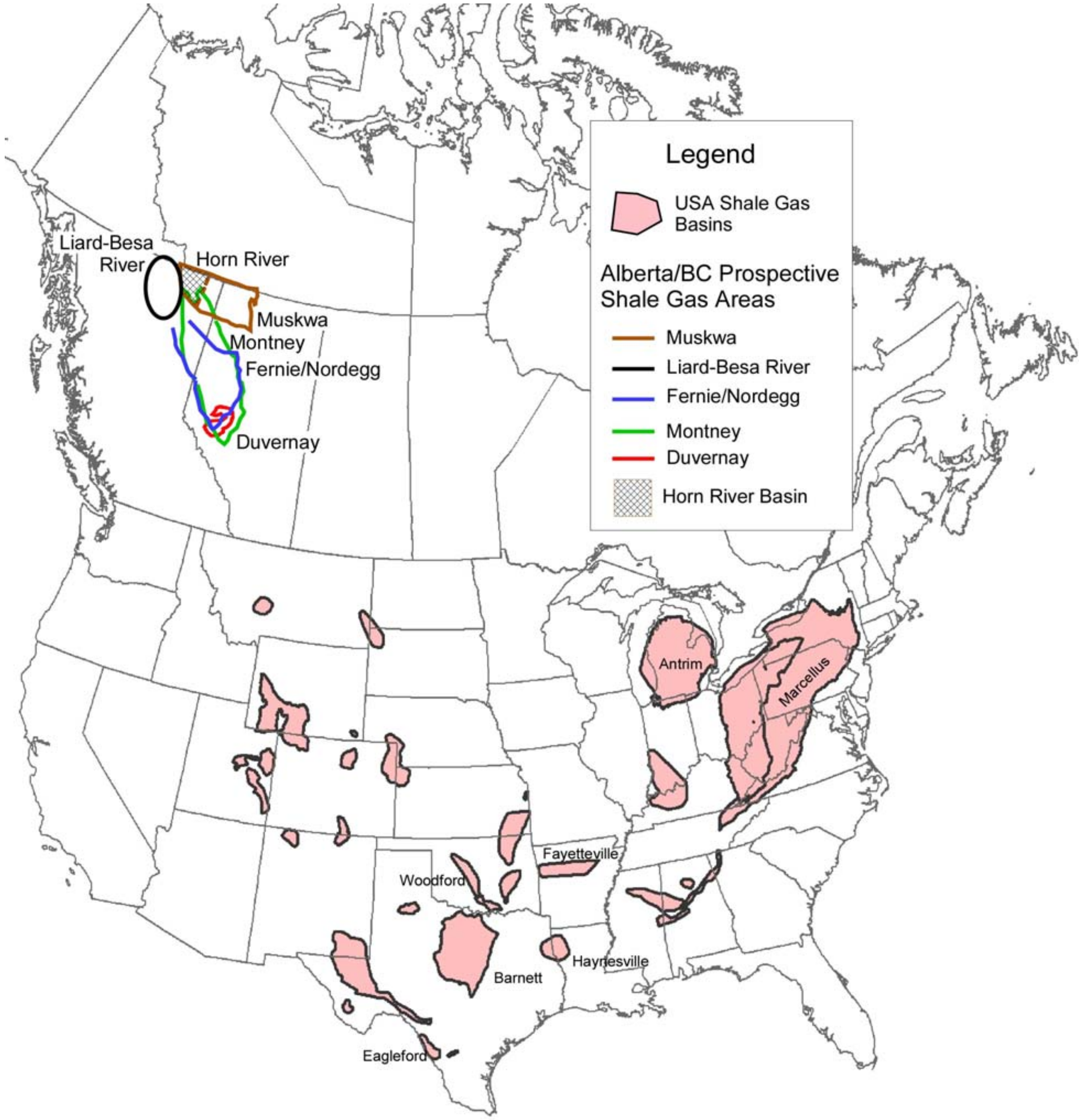
Jurisdictions and Shale Gas Plays

Location	Regulator	Shale Gas Plays
British Columbia	British Columbia Oil and Gas Commission (B.C. OGC)	Horn River Montney Liard-Besa River
Saskatchewan	Saskatchewan Ministry of Energy and Resources	No shale gas activity at this time
Louisiana	Louisiana Department of Natural Resources, Office of Conservation	Haynesville
Michigan	Michigan Department of Natural Resources and Environment, Office of Geological Survey	Antrim
New York	New York State Department of Environmental Conservation	Marcellus
Oklahoma	Oklahoma Corporation Commission	Woodford
Pennsylvania	Bureau of Oil and Gas Management, Department of Environmental Protection	Marcellus
Texas	Railroad Commission of Texas	Barnett Haynesville Eagleford

The geological and geochemical characteristics of each shale gas play are relatively unique. However, fundamental aspects of shale gas development common to other areas can be expected with shale gas development in Alberta, too. Shale gas plays cover potentially very large continuous areas, thousands to tens of thousands of square kilometres. Gas-in-place volumes are enormous, even for the smaller plays. Depths of prospective shale gas zones range from relatively shallow (less than 300 metres [m]) to quite deep (greater than 3000 m).

In Alberta, there is potential for both shallow and deep shale gas plays. Drilling long-reach horizontal wells is the preferred exploitation strategy for the deeper, thicker gas shales, where as vertical wells may more typically be used to exploit shallower, thinner shales, such as those in eastern Alberta. Whether a well is horizontal or vertical, stimulation of the shale formation is necessary for economic production, and this is currently most commonly done by hydraulic fracturing.

Given the common characteristics of shale gas development, many of the regulatory issues that have arisen are similar from one jurisdiction to another, but an issue’s importance and the regulatory response may be influenced by regional circumstances. Issues that have arisen in other jurisdictions can be expected with shale gas development in Alberta.



North American Shale Gas Plays

4 Common Regulatory Challenges

The survey identified a number of challenges facing regulators and industry across virtually all jurisdictions.

Well Spacing Requirements

- Optimal well spacing is important for efficient development of unconventional gas and is relevant to conservation, equity, and efficient and orderly development.
- Well densities significantly higher than conventional well spacing are necessary for reasonable recovery of unconventional gas in place.
- Regulators are approving increased well density or waiving standard well spacing by a variety of regulatory processes.

Hydraulic Fracturing

- Increasing public, media, and government attention is being focused on the potential for hydraulic fracturing of shale gas reservoirs to contaminate useable water aquifers with fracturing fluid chemicals and natural gas, despite no proven cases of hydraulic fracturing of deep zones having caused such a problem.
- There have been occurrences of intra-zone communication between wellbores that are being hydraulically fractured and adjacent wellbores, that are either producing or being drilled, sometimes considerable distances away. This has raised operational concerns because of the high fracturing pressures.
- There has been at least one instance of a mineral rights ownership issue arising from hydraulic fracturing outside of the intended zone.

Water Management

- Very large volumes of water, tens of thousands of cubic metres per well, are needed to hydraulically fracture shale gas wells using current technology.
- Most of the water used in shale development to date has been fresh surface water or groundwater.
- Access to sufficient water is critical to development, but cumulative effects on the sources of large water withdrawals must be managed.
- Transporting large volumes of water by truck or pipeline presents challenges.
- On-site containment and the transport and disposal of large volumes of used hydraulic fracture fluid must be carefully managed.
- Limiting overall water use, especially of fresh water, by using water with higher total dissolved solids and by reusing and recycling hydraulic fracture fluid is being promoted.

Landowner/Public Concerns

Landowner and public concerns include

- groundwater contamination caused by drilling and hydraulic fracturing
- spills of fracturing fluids and produced water
- heavy truck traffic during drilling and hydraulic fracturing operations
- noise
- light pollution
- effects of emissions on local air quality
- property damage
- density of development

Environmental Issues

Environmental issues identified in the survey include

- cumulative effects of surface infrastructure over very extensive play areas
- large multiwell pad sites requiring continuous operations for extended periods (12–24 months) to drill and complete wells
- water (see Water Management)
- air emissions (nitrogen oxides, hydrocarbons, carbon dioxide)

Regulatory Process

Regulatory process challenges identified in the survey include

- variance from standard well spacing requirements
- potential inefficiencies of processes used to assess and approve conventional oil and gas well drilling when applied to multiwell pad unconventional gas scenario
- effectiveness of historical well approval and other regulatory processes to adequately consider broader cumulative impacts of unconventional gas development across a large landscape
- adequacy of systems for management of water access, transport, storage, use, and disposal
- potential for impact of hydraulic fracturing operations on adjacent wellbores and operations
- sufficient regulatory resources for high industry activity

Information Collection and Dissemination

- Some information gathered for reserves assessment and for prudent management of conventional reservoirs may not be relevant to unconventional gas development.
- Different information may be necessary to better understand unconventional gas development.
- Data collection is costly and the economics of unconventional gas is marginal in times of low gas prices.
- Operators wish to keep confidential information that they deem to provide some competitive advantage.

5 Detailed Survey Observations and Regulatory Change Opportunities

This section provides a discussion of the issues arising from unconventional gas development and of the regulatory response to those issues by the various jurisdictions. Based on its review, the Jurisdictional Review Task Team identified a number of regulatory changes the ERCB could consider in developing a leading edge regulatory framework for unconventional gas.

For background, Appendix 1 provides detailed input from the regulator in each jurisdiction and a collage of the operator responses. The appendix is organized by the following subject areas as identified in the survey:

- Resource Appraisal and Reserves
- Reservoir Development
- Drilling and Completion
  - Water Management
- Landowner and Public Concerns
- Environment
- Regulatory Processes
- Information and Dissemination

Resource Appraisal and Reserves

The primary issue is the need, the practicality, and the validity of applying traditional deterministic reserves estimation techniques to unconventional gas resources.

Industry argues that in ultra-low permeability reservoirs, the collection and use of reservoir pressure data is impractical, and costly and yields invalid material balance estimates of gas in place. Furthermore, the volume of recoverable gas is the more relevant metric for operators in terms of project economics and evaluating the merit of different well spacing and drilling and completion techniques. After a sufficient period of stabilized production, production decline analysis will determine the recoverable reserves from the zone of reservoir affected by the fracturing of a wellbore.

Industry also argues that control wells dedicated to gathering pressure and flow data will be too costly and that the data is not needed.

Of the jurisdictions surveyed, only British Columbia has resource appraisal functions similar to those of the ERCB in Alberta, so B.C. respondents provided substantive comments on subject. The Oil and Gas Commission (OGC) and the Ministry of Energy, Mines and Petroleum Resources (MEMPR) both have a role in estimating B.C.'s reserves, and the difficulties applying traditional reserves estimation methods to unconventional gas are acknowledged. B.C. is considering a statistical analysis approach to estimating gas in place and recoverable gas volumes.

The ERCB's resource appraisal functions are primarily driven by its conservation and orderly development mandates and by its mandate to provide accurate resource appraisal information for the province. As part of its unconventional gas initiative, the ERCB is evaluating options for estimating reserves of unconventional gas. This work should continue as a priority and will influence information and reporting requirements.

Regulatory Change Opportunities

- The characteristics of unconventional gas might facilitate a more statistical approach to reserves estimating which could involve less data collection and analysis than with deterministic methods, and less ERCB effort with comparable accuracy and ability to meet ERCB mandates.

Reservoir Development

Unconventional gas resources are characterized by reservoirs that exhibit extremely low permeability and are laterally extensive. They may be very thick, as with some prospective shales, they may be a series of multiple thin stacked layers, including thin coal zones, or they may be a combination involving very thick sections of multiple, stacked, gas-bearing zones of varying lithology as in Alberta's deep basin tight gas. Vertical wells with commingling of multiple zones will be optimal in some cases. Long-reach horizontal wells will be optimal in other cases.

Common to all types of unconventional gas is the need to fracture the reservoirs to achieve permeability sufficient for gas to flow. The effective reservoir volume that will contribute to an unconventional gas well's production is therefore heavily influenced by the reservoir volume stimulated by fracturing.

Optimal well spacing is required to efficiently develop unconventional gas; it affects conservation, equity, and efficient and orderly development.

Neither operators nor regulators know currently how to determine optimal well spacing. It is linked to fracture stimulation effectiveness, as it is believed there is minimal production from reservoir outside of the fracture zone of influence. In turn, fracture effectiveness is related to various geotechnical and shale characteristics that vary from one play to another, and possibly within a play itself.

Unconventional gas development in every jurisdiction appears to be proceeding at well densities greater than the Alberta standard spacing of one gas well per 256 hectares (1 square mile). Regulators are approving special well spacing in one form or another that allows for increased well density for unconventional gas development. In U.S. jurisdictions, the size of a spacing unit associated with a well (or wells) may be determined by the parcel size of individual mineral leases (which sometimes may need to be pooled to achieve a minimum size to allow the drilling of a well). In some jurisdictions, both the size and the shape of spacing units are modified to accommodate the drilling of lengthy horizontal wells.

Spacing rules for unconventional gas typically specify a minimum distance between a proposed well and the lease line to prevent off-lease drainage, most commonly 330 feet (ft.) (100 m). Minimum interwell distances may be specified but not always. In some cases, multiple horizontal legs may be drilled from a single vertical motherbore permitted as a single well.

Of note is a response that indicated the need to drill a second well in a spacing unit in an upper interval of thick shale after a wellbore lower in the same shale had produced for some time. The drawdown pressure of the portion of reservoir contributing to the original production precluded commingling with the targeted upper interval, necessitating the drilling of a second well completed in the upper interval.

In very thick continuous shale (thicker than the extent of vertical fracture propagation) or in shale that contains multiple intervals isolated by vertical flow barriers, opportunities to simultaneously produce from horizontal wellbores at various depths would ensure that pressure depletion occurs more evenly across all intervals, so that the pressure differentials do not preclude later commingling and necessitate the need for a new standalone wellbore.

Operators are of the view that increased well density is necessary. They also report that the ERCB's current regulatory approach of approving special well spacing only after need has been demonstrated (by sufficient production history and other relevant information) will preclude efficiencies gained by initially drilling multiple wells from a single pad. As well, operators are generally of the view that with the limited drainage areas typical of CBM and, especially, shale gas, a modest buffer distance between a wellbore and offsetting mineral rights of different ownership is sufficient to prevent inequitable drainage, regardless of well density.

Regulatory Change Opportunities

- Increased well density is the standard for unconventional gas if reasonable resource recovery levels are to be achieved. Obtaining variance from standard well spacing as specified in the Oil and Gas Regulations by the special spacing approval processes will be unnecessarily burdensome for industry and the ERCB and may hinder efficient development. Providing for increased well density by regulation rather than by application and approval would reduce regulatory burden and provide operators with flexibility to develop optimally with minimal risk to ERCB mandates for conservation, equity and orderly and efficient development.

Drilling and Completion Operations (Includes Hydraulic Fracturing and Water Management)

In areas where unconventional, primarily shale gas is currently being developed, considerable attention is on the possibility for hydraulic fracturing of shale gas reservoirs to contaminate useable water aquifers with fracturing fluid chemicals and natural gas. For shallower zones, this is a recognized risk that must be managed because the fracturing operation is nearer the base of groundwater. For deeper zones, the likelihood that fracturing fluid or natural gas will migrate up to the groundwater table is much less likely because of the thousands of metres of vertical separation. In some geological settings, extensive natural fracturing might create a potential conduit to the groundwater table. More likely, potential conduits are existing wellbores (or the new well being fractured) with inadequately cemented casing.

Despite heightened concern about contamination of useable groundwater aquifers (primarily in Pennsylvania and New York) by hydraulic fracturing of deep shale formations, no such cases appear to be documented with evidence. Nevertheless, New York has adopted a precautionary approach and currently has a moratorium on shale gas drilling, Pennsylvania is implementing enhanced well casing and cementing requirements to reduce the likelihood of communication between deep fractured zones and shallower zones outside of the wellbore, and the U.S. Environmental Protection Agency is developing terms of reference for further study of hydraulic fracturing and whether it should remain exempt from federal regulation for the protection of useable groundwater.

There has been public pressure in U.S. jurisdictions for disclosure of the chemicals added to hydraulic fracturing fluid. The regulatory trend appears to be towards, as a minimum, requiring that operators submit this information and, in some cases, that the information be made available to the public. Generally, producers surveyed did not indicate that they would be opposed to this.

Instances of communication between a wellbore undergoing massive hydraulic fracturing and nearby oil or gas wellbores that are producing or being drilled have been observed. Distances have been up to several hundred metres. In some jurisdictions, operators notify well owners of their intent to conduct hydraulic fracturing operations. In response to a number of incidents in British Columbia, the Oil and Gas Commission recently introduced mandatory notification requirements.

At least one instance of fracturing from the zone where rights are owned into the zone above where ownership is different has been brought to the attention of a regulator.

Operators conducting hydraulic fracturing operations sometimes use fracturing monitoring methods, such as microseismic and tracers, to assess fracture characteristics. No jurisdiction currently requires that operators undertake such monitoring or submit the results or analysis of such monitoring for either the regulator's use or to be available publicly, although some regulators are of the view that it would be useful to have the information submitted.

The very large volumes of water needed to hydraulically fracture shale gas wells with current technology makes water consumption a critical issue in shale gas development. With hundreds of wells to be drilled over large shale gas plays, water management warrants considerable regulatory attention and could limit where, when, and how fast shale gas development occurs.

The level of concern about use of large volumes of fresh surface water and potable groundwater varies among the jurisdictions, but it generally relates to water availability and increases during dry or drought periods. In British Columbia, persistent dry conditions during summer 2010 caused the Oil and Gas Commission to suspend approved water withdrawals in some watersheds. Although fresh water is currently the largest portion of water sourced for hydraulic fracturing, all jurisdictions promote the use of non-useable (i.e., non-potable) water and the recycling of fracture fluid flowback for subsequent fracturing use. Disposal of hydraulic fracture fluid flowback is a concern in some jurisdictions because of the limited capacity of deep aquifers to accept the large volumes, necessitating alternatives to deep well disposal.

Water is transported using temporary surface pipelines and by trucks. Due to the large water volumes, truck traffic can have serious impacts. Water storage, usually on a well site, is typically in closed tanks, lined pits, or open-top engineered temporary storage (C-ring or corrugated steel ring).

Operators in Alberta stressed the importance of obtaining timely authorization to access large volumes of water. As well, use of saline water from deeper aquifers requires costly investment, and some authorization to use specified volumes of saline water would provide enhanced security for the initial investment., Regulatory changes may be necessary to allow for new water storage options to accommodate hydraulic fracturing operations. Also noted was the need to change the permitting of water withdrawals from borrow pits to facilitate the use of surface water runoff.

Regulatory Change Opportunities

- Assess need and develop an effective regulatory response to manage the risk of hydraulic fracturing creating a conduit, via existing wellbores, to surface or porous formation outside of the zone being fractured. Possible response components: evaluation of potential conduits, operational considerations such as planned wellbore geometry and fracturing program design, remediation of compromised wellbores, and assignment of responsibility.

- Assess the risk of natural fracturing allowing gas to move from a post-fractured gas shale to a shallow water aquifer and what information would need to be evaluated to mitigate the risk.

- Assess the need for minimum separation distances (i.e., buffers) between hydraulic fracturing and acid gas disposal schemes (also consider potential carbon dioxide sequestration schemes) and enhanced recovery schemes to prevent loss of scheme cap rock integrity.

- Manage the risk of fracturing pressure communication interfering with offsetting producing or drilling wells by requiring notification of intent to fracture. Also, evaluate the need for extraordinary drilling requirements in areas of past and/or present fracturing operations because of the potential to encounter overpressured zones during drilling.

- Evaluate existing equity-related legislation for regulatory remedies of potential cases of fracturing vertically into a zone of different ownership.

- Evaluate the public interest value of microseismic and other fracture propagation monitoring methods to increase understanding of fracture behaviour.

- Evaluate the need to collect and disseminate hydraulic fracture fluid chemical composition (pre-fracture) information.

- In collaboration with Alberta Environment, evaluate potential regulatory options to effectively manage water uses for shale gas development. This might include regional or project-based water management plans to accompany commercial shale gas development proposals. Plans would evaluate all feasible water supply options, including saline aquifers, as well as assess impacts of water withdrawal on supply sources, evaluate source locations with consideration of transportation options and impacts, and evaluate recycling and disposal options.

- Advise Alberta Environment of industry-suggested regulatory opportunities to encourage the use of borrow pits to supplement hydraulic fracturing water needs.

- Evaluate the need for authorizing/allocating withdrawals of saline water from deeper aquifers to protect capital investment.

- As a minimum, ensure that there are regulatory requirements for the approval and operation of fracture fluid recycle facilities and/or schemes, and evaluate regulatory options to encourage recycling of fracture fluid flowback.

- Evaluate the adequacy of current water storage and waste regulation to accommodate hydraulic fracturing.

- Evaluate whether regulatory requirements for approval and operation of temporary water delivery pipelines meet hydraulic fracturing water transport needs.

Landowner/Public Concerns

The most common landowner complaints related to unconventional gas development in jurisdictions surveyed are traffic, noise, light pollution, local air quality, groundwater contamination, spills, general disturbance, and property trespass and damage. Concern that hydraulic fracturing is contaminating groundwater is increasing and is driving an upcoming study by the United States Environmental Protection Agency (EPA). Increased subsurface well density can translate to increased density of surface sites and operations, which compounds the surface impacts.

In some jurisdictions, local surface effects of unconventional gas development are exacerbated by the close proximity of drilling sites to urban areas. Unconventional gas is also being developed in areas that have not had conventional oil and gas development, so local landowners are unfamiliar with what to expect.

Responses to local concerns have included establishing setback distances between well sites and residences or other inhabited structures, and for well sites close to people, imposing stricter operating requirements for noise suppression, hours for construction activity and heavy truck access, venting and flaring, site lighting, fencing and maintenance, and dust, vibration, and odours.

In response to local concerns that hydraulic fracturing causes groundwater contamination, some regulators have implemented, or are considering implementing, a requirement that operators disclose fracturing fluid composition.

Regulators commonly have information on their Web sites about shale gas development in their state or province to inform the public about activities and issues. Regulators may also target information more directly at landowners and communities that are being affected or might expect to be affected by unconventional gas development.

Alberta landowner concerns are likely to be similar to those raised in other jurisdictions: groundwater protection, surface disturbance, flaring, noise, traffic, and other nuisances caused by drilling and completion operations.

Because of the large areal extents of both shale and coal seams that are prospective for gas production, the potential for these resource developments to encroach on future growth areas of Calgary, Edmonton, and other urban areas in Alberta could necessitate increased planning and extraordinary regulatory requirements to mitigate impacts of operations. Many rural landowners today are affected by surface well sites and infrastructure associated with coalbed methane development, and this can be expected as well for shale gas development.

Drilling and completion operations for unconventional gas wells may be considerably more disruptive to local landowners and communities than conventional gas or oil drilling. Extended periods (24–36 months) of virtually continuous industrial activity at a single, large well pad site will be necessary to drill and complete numerous wells. Truck traffic to and from the site can be expected to be very heavy, moving in drilling equipment and supplies, fracturing equipment and supplies, and especially large volumes of water needed for hydraulic fracturing.

Siting of pad drilling operations and separation between residences and wellsites will need to be considered carefully to manage the noise and other activity-related impacts of these drilling and completion operations on landowners. Drilling multiple long-reach horizontal wells (as is most likely to exploit shale gas) from a pad site should allow for flexibility in siting surface drilling locations so that reasonable distances from residences can be maintained.

Regulatory Change Opportunities

- Evaluate the need for regulatory mechanisms to effectively manage the number, size, and location of surface sites to limit surface disturbance to levels tolerable for other surface users.
- Adopt leading edge risk assessment and regulation to prevent potential for any impact to shallow groundwater (see Drilling and Completion Operations Regulatory Change Opportunities above). Also, see ERCB's current shallow fracturing requirements in ERCB Directive 027.
- Evaluate the need for increased minimum separation distances between shale gas well sites and occupied buildings to manage the impacts of extended periods of high activity needed to drill, complete, and fracture multiple wells.
- Evaluate the need for modified regulations related to visual, noise, and traffic impacts of drilling and completion operations.
- Develop an effective, broad-based communication strategy to provide unbiased, factual information about unconventional gas development to Albertans.

Environmental Issues

Characteristics of unconventional gas resources and the technology to develop them can be expected to result in large, contiguous gas plays with a concentration of related surface infrastructure over areas larger than experienced with conventional oil or gas fields. This may cause some unique environmental impacts and cumulative effects issues, but it may also provide opportunities to take a broader approach to planning development and to implement mitigation strategies.

Some of the jurisdictions surveyed have implemented procedures to assess environmental impacts and develop mitigation measures on a project-area basis. Surface footprint is recognized as an important issue, and specific regulatory response to it has included encouraging and, in some cases, requiring pad development to limit the number of surface sites. Operational efficiencies that reduce costs of drilling, completing, and tying in multiple wells from a single pad site will likely drive this development model.

Surface impacts associated with well sites, roads, and pipeline rights-of-way present wildlife habitat preservation challenges. In some areas, surface footprint, activity levels, and the need for year-round access will challenge the objective of preserving of caribou and grizzly habitat and will require careful study and planning. Of note is the action taken by the British Columbia Ministry of Energy, Mines and Petroleum Resources in 2010 establishing "Resource Review Areas" within boreal caribou ranges where no new petroleum and natural gas tenures will be granted for the next five years.

Air quality impacts mentioned most in the responses include emissions of carbon dioxide stripped from the gas production (note that the proportion of carbon dioxide in the gas production stream increases in some shale gas plays as the producing life advances); sulphur dioxide and/or hydrogen sulphide from treating sour water for use as hydraulic fracture fluid, NOX and other emissions from compressors; pollution from diesel engines; and ground level ozone. The relatively new Eagleford shale gas production in Texas contains small amounts of hydrogen sulphide, which may also result in sulphur emissions.

In addition to implementing project-based environmental impact assessment and stewardship plans, jurisdictions have responded to shale gas development with regulatory changes related to air emissions and to water handling and disposal and well casing and cementing requirements to protect groundwater and surface water.

Operators suggested that unconventional gas regulation should be focused on groundwater protection and managing the surface footprint. Operators also advised that the most efficient development of shale gas will require year-round access to well sites for operations that may extend for two to three years on a site, and that although this may conflict with current seasonal access limitations in some parts of Alberta, it can be overcome by operators adhering to best operating practices.

Regulatory Change Opportunities

- Collaborate with Alberta Environment, Alberta Sustainable Resource Development (SRD), and industry to develop the most effective ways to assess and manage the cumulative surface infrastructure impacts of commercial shale gas development. This should include industry developing best practices for planning, constructing, and operating surface infrastructure to minimize environmental impacts.

- Based on preliminary knowledge of potential shale gas development, initiate early work with SRD and industry to identify potential conflicts with habitat preservation areas in Alberta and to develop possible operational solutions to access and timing restrictions.

- See Drilling and Completions Regulatory Change Opportunities for discussion of water use and protection.

- Although unconventional gas production does not appear to have significant unique air emission issues associated with it, a review of current ERCB and Alberta Environment regulations and standards would be appropriate to ensure they are adequate to maintain Alberta's current air quality given the expected intensity of shale gas development.

Regulatory Processes

Recognizing that unconventional gas has unique characteristics, new or modified approaches to regulate it effectively may be needed.

As noted in the discussion on reservoir development, reduced well spacing (i.e., increased well density) is common to unconventional gas development. All jurisdictions have regulatory processes that enable variance from standard well spacing when the need is demonstrated, and it appears that spacing variance, when requested, is routinely granted to accommodate unconventional gas drilling. Special spacing may be granted by field-wide rules. An example of a proactive regulatory process is the B.C. OGC's approval of the Liard-Besa River Development Scheme, which, among other things, waived standard well spacing requirements for the entire prospective play area from the outset.

With respect to approvals to drill wells, jurisdictions appear to be continuing with processes similar to those used to permit conventional wells. In some cases, very high drilling activity levels have strained regulatory resources. Because the typical shale gas drilling situation has multiple horizontal wells being drilled from a single surface pad site, some jurisdictions are looking at ways to streamline the drilling approval process; perhaps, for example, focusing more on the pad than on the individual wells on the pad.

Because of the large areal extents of unconventional gas plays, and with increasing interest in cumulative effects, some jurisdictions review and decide on "projects" rather than on well approvals, pipeline approvals, water storage and disposal approvals, and roads, etc., separately.

Of key importance to unconventional gas operators is efficiency of development. Costs, delays, and uncertainty caused by regulatory processes will hinder unconventional gas economics. Operators recommended changes to current ERCB processes to allow special spacing, including provision of a baseline well density of eight wells per section. Pad-based well licensing, with appropriate rules to enable pad drilling cost and time efficiencies, should be considered. Requirements related to emergency response plans and approval of flaring should be based on a well pad rather than on individual wells on the pad to avoid duplication of process, and especially of consultation. Specific well licensing requirements, such as those related to the setting of conductor pipe and to the 12 month licence expiry period, should be evaluated to ensure that they do not hinder the efficiency gains of drilling multiple wells from a single pad. Pre-approval of pipelines would be appropriate because of the relative certainty of the need to tie in all well sites, and it would reduce the overall time to get wells on production.

Operators consider project- or scheme-based approvals to be potential regulatory streamlining, although the risk that an objection to one proposed site or facility will delay the overall larger project is a concern. Operators would seek clarity from the ERCB about how objections would be handled in the context of a project-based application/approval format.

Unconventional gas development may lead to more consultation with First Nations, so improvements in the consultation process, both in resources that allow First Nations to consult in a timely way and in decisions about the adequacy of consultation within government, are needed.

Access to large volumes of water from a variety of sources for hydraulic fracturing will be needed, so timely assessment and approval processes are required. Water storage requirements on well sites are beyond those typical of conventional oil or gas drilling and completion operations, so new requirements and/or approval processes may be needed to address this difference.

Regulatory Change Opportunities

- The development of extensive unconventional gas plays, sometimes described as a manufacturing, lends itself to new regulatory approaches especially related to assessment and approval of a development or scheme. Some distinction should be made between early trial development that tests whether a play is prospective (which could fit the ERCB's traditional well licensing process) and full-scale commercial development involving multiple-pad well sites, roads, pipelines, and water handling facilities over a larger area. A project- or scheme-based approval process would enable an effective mechanism to assess cumulative effects, water management, and impact mitigation strategies. The need for an efficient regulatory process is critical to development.

- If project-based approvals are to be considered, ERCB standing criteria and requirements for notification and consultation will need review and possibly modification.

- Investigate and pursue arrangements with SRD to facilitate the sharing of information about compliance with and/or applicability of the Government of Alberta's First Nation consultation guidelines as applied to a given project. Consider the current memorandum of understanding (MOU) between the ERCB and SRD for conventional facilities.

- Evaluate the potential benefits of licensing multi-well pads as a single entity to eliminate multiple notification and consultation requirements and multiple approvals. Evaluate the well licence expiry period and the drilling operational requirements to ensure that they do not hinder multi-well pad drilling.

- See Reservoir Development Regulatory Change Opportunities for comments on well spacing. Traditional approaches to regulation of well spacing would preclude the efficiencies of drilling and completing multiple wells sequentially on a pad site, and they could cause more disturbance by requiring that a site be revisited to drill additional wells numerous times through its life.

Information Collection and Dissemination

The nature of unconventional gas reservoirs and related exploitation technology are different enough from conventional gas to warrant consideration of the whether the suite of geological and reservoir data, and current requirements for collecting it, are appropriate.

State regulators surveyed may collect certain types of geological and reservoir engineering data for classification of production or as needed for special rule making, but their resource appraisal, reserves assessment, or information dissemination mandates are not as strong as those that guide Canadian regulators. One US regulator noted that more information about individual well production performance, hydraulic fracturing results, reserves estimates, and reservoir characteristics would be helpful when evaluating proposed unconventional gas development plans. US regulators do not appear to have introduced any special data confidentiality provisions to accommodate unconventional gas development.

In British Columbia, consideration is being given to reducing the frequency of collection or "coverage" of some types of data while focusing more on collecting information considered highly relevant to determining the most effective reservoir development. The high-value data would be gathered from specified "data wells," which could be offered extended confidentiality provisions as an incentive.

A new data type emerging from unconventional gas development is the monitoring of fracture propagation by various means, including microseismic. Fracture propagation is potentially relevant to reservoir development considerations and to operational concerns. In British Columbia, the OGC is considering the potential value of requiring that microseismic information be submitted.

At the request of operators, the OGC has, in some cases, granted extended confidentiality periods for data submitted from some wells, but it notes that this has led to complicated administration and some difficulty deciding when extended confidentiality treatment should end as development proceeds. Of note is the Commission's treatment of the Liard-Besa River Development Scheme area as an experimental scheme with well data confidential for three years instead of one year.

Operators expressed concerns about the relevance of some ERCB data collection to unconventional gas, both for coalbed methane and for potential shale gas, especially as it pertains to reserves assessment. Also of concern is the practicality of obtaining traditional reservoir pressure measurements because of the ultra-low permeability of the reservoirs and the commingling of multiple zones. For some operators, the high cost of obtaining data to comply with ERCB requirements, especially very early in an operator's assessment of the economic viability of a prospect, may be prohibitive. While operators appreciate the ERCB's need for certain types of information, it is important that operators understand how the ERCB is using it, how it's relevant to the ERCB's mandate, and that it is cost effective. Operators do not support of the control well concept for data collection because of its high cost.

Data confidentiality is an important issue for Alberta operators, with some suggesting that extended confidentiality periods of three to four years for well data are necessary to provide competitive advantage to operators willing to invest in shale gas development. Data confidentiality in shale gas developments appears to be in a state of transition in British Columbia. An extended period of confidentially is being granted to the Liard-Besa River Scheme. There was no sense that data confidentiality is an important issue in the US jurisdictions, although the data submission requirements are very different. Increased data confidentiality is a critical issue for the ERCB's information collection and dissemination and other regulatory mandates. There are potentially broad public interest considerations that will need to be carefully balanced with industry objectives.

Regulatory Change Opportunities

- Recognizing the differences between unconventional and conventional gas, it appears there is merit in fully assessing the information required, in terms of both relevance and adequacy, to meet the needs of the mandates. Some types of information collected traditionally might be of limited use or impractical to obtain, while new information types specific to shale properties and how unconventional gas wells are drilled and completed may be necessary to understand how unconventional resources can be optimized.

- Once basic data needs are determined, submission requirements should reflect the need for and use of different types/amounts of data through all stages of development; that data collection is limited to that necessary to meet all ERCB mandates and that the cost of data collection is considered as well as the benefits.

- The position of operators that increased confidentiality is needed to protect competitive advantage in order for shale gas investment to occur should be considered and the specific nature of data for which confidentiality is needed, and any potential broader implications, should be evaluated at a more detailed level.

Appendix 1 Detailed Summarized Responses

Resource Appraisal and Reserves

Objective
To understand resource appraisal and reserves determination approaches and data requirements for unconventional gas resources in other jurisdictions.

Issue
In Alberta, initial steps have been taken to realign data requirements for well testing (pressure and flow) and unsegregated production and analysis procedures for resource/reserve assessments, but ongoing practical problems in achieving the right balance and procedures to appraise the unconventional gas resource potential and reserves persist.

Respondent	Comments - Resource Appraisal and Reserves
British Columbia	B.C. is currently, using traditional reserves estimation methods, but it is also considering adopting a more statistical approach that focuses on an area via averages over many wells rather than a well-by-well approach.
Saskatchewan	Based on experience with shallow gas resources such as those found in the Milk River Formation, it is expected that it will be necessary to rely primarily on production decline analysis for assessment of unconventional gas reserves.
Louisiana	There is no mandate to conduct resource appraisal.
Michigan	The Office of Geological Survey does not calculate reserves, but collects geologic and reservoir data for the purpose of classifying reservoirs and wells for substance: gas, gas condensate, or oil.
Texas	The Railroad Commission does not have a mandate to conduct resource appraisal. Reserves information may be provided and evaluated through the hearing process. In addition, the local land appraisal district may have information.
Operators	Traditional material balance methods for estimating reserves are not reliable for unconventional gas because pressure data gathered in very low permeability reservoirs are neither accurate nor representative of reservoir pressure. Production decline analysis is the preferred method. Gas Desorption testing for shale as currently specified by the ERCB will not yield useful information for estimating OGIP for shale gas.

Reservoir Development

Objective

To understand how other jurisdictions maximize resource recovery, promote orderly and efficient development, and address equity among owners.

Issue

There is a need to develop efficient regulatory processes that facilitate the development of unconventional gas reservoirs, such that resource recovery is not jeopardized, development is orderly and efficient, and equity is provided for.

Respondents	Comments – Reservoir Development
British Columbia	"Good Engineering Practice" (GEP) applications are filed to request variation from standard well spacing. Operators determine optimal well density to recover the resource and make an application. GEP approvals are evaluated and based on the requested well density but do not specify a well density in the approval. Commission Order 10-15-001 approved the extensive (934 303 hectares) Liard-Besa River Development Scheme as an experimental scheme for development of the Besa River Shale formation. The order waives standard well spacing in the development area, provides for a three-year well data confidentiality period, and requires that an Environmental Stewardship Plan be prepared by scheme area operators.
Saskatchewan	Operators may apply for a change in well spacing, but must demonstrate that additional reserves will be recovered due to the change in spacing. This applies to both conventional and unconventional.
Louisiana	Well spacing rules include a 330 ft buffer around the drilling spacing unit (DSU) which can be adjusted to create units and, for shale gas, no well can be closer than 660 ft from any other unit well (interwell distance). For tight gas, conventional rules, which specify a 2000ft interwell distance, apply. For CBM, there is no interwell distance. The Office of Conservation has amended requirements generally to adapt for the use of horizontal wells and reduced well spacing. Allowance for the creation of larger units with multiple wells per unit and standardized definitions for productive intervals for unitization purposes have been introduced.
Michigan	Operators may apply for a Uniform Spacing Plan (USP) to obtain relief from standard well spacing for Antrim Shale wells only. A USP is a pooled area, larger than the standard drilling unit. A USP promotes efficient and orderly development of Antrim Shale gas by limiting vertical well density to a maximum of one well per 80 acres but providing for as many horizontal drain holes drilled from each vertical well location as deemed appropriate by the operator without further application across an area that is larger than a single 80-acre drilling unit with horizontal drain hole locations limited only by a 330 foot setback from the boundary of the USP. By Special Order, drilling of "Antrim Twin Wells" (a second well drilled in a single drilling unit) is permitted to enable production from a second distinct reservoir unit (upper zone) present in the Antrim Shale. In many areas, the pressure of the lower Antrim Shale zone has been depleted by years of production and now the pressure differential between the upper and lower reservoir units is too great to achieve efficient production from both zones if they are commingled in a single wellbore. A horizontal drain hole is considered to be a completion technology and a new horizontal drain hole drilled from an existing vertical well may be added by applying for a "Change of Well Status" rather than a permit to drill a new well. This process existed prior to the Antrim Shale development as well but the modification made since the Antrim development is to review these applications for conformance with well spacing requirements.

Respondents	Comments – Reservoir Development
New York	Statewide spacing rules for horizontal wells provide for one well per 40 acres plus the necessary and sufficient acreage to maintain a 330-foot setback between the wellbore in the target formation and the spacing unit boundary. Statewide spacing option for shale wells provides for spacing units of up to 640 acres with all the horizontal wells in the unit drilled from a common well pad. This requirement provides flexibility to avoid environmentally sensitive locations within the acreage to be developed and is expected to be the most common approach to shale gas development in New York using horizontal drilling and high-volume hydraulic fracturing. A variance from statewide spacing or a non-conforming spacing unit requires the Department to issue a well-specific spacing order following public comment and, if necessary, an adjudicatory hearing. Variances from statewide spacing or non-conforming spacing units, with justification, which could result in a greater well density for any of the above options.
Oklahoma	Modification to DSU size and shape are made to accommodate horizontal drilling. Exceptions to standard well spacing of one horizontal well per 640 acres located at least 660 ft. from the lease line, are routinely granted for shale gas development. Increased well density and relaxation of the lease line setback to 330 ft. is allowed for shale gas wells. Interwell spacing between horizontal legs is maintained at 660 ft.
Pennsylvania	No prescribed well spacing, however, Bureau recognizes the importance of set spacing in preventing economic waste.
Texas	Standard state-wide spacing rules require a well to be a minimum of 467 ft. from a lease line; a minimum interwell distance of 1200 ft.; and a 40 acre density; however operators can apply to the Commission to establish field rules as a variance from state-wide rules. Barnett spacing is minimum of 330 ft. between well and lease line; no minimum interwell distance, and 20 acre density for gas and 40 acres for oil.
Operator Response	Well spacing should not be prescribed by the regulator because neither the regulator, nor operators have a definitive understanding of what optimal spacing should be. As industry develops the resource and gains knowledge about the optimal balance of wellbore density and placement, and size and placement of hydraulic fractures, appropriate reservoir development strategies will be found. It is in the interests of both industry and the regulators to maximize recovery without over drilling. Industry should have a lead role in managing reservoir recovery matters. Downspacing should be permitted without having to prove that it is necessary as it can be challenging obtaining the right data to support a downspacing application. The current application process for special spacing is too time consuming and requesting incremental increases to well density based on production history does not match well with unconventional gas development plans to drill numerous wells (at increased well density) early on. The unique nature of unconventional gas development should be recognized and well spacing should allow for a minimum of eight wells per DSU as standard spacing. Operators should be allowed to commingle all shale zones within a play without conditions or approval process. Both downspacing and commingling is required because the nature of the resource is such that more wells and more completions within the wellbore are required for the resource to be economical. Industry views that equity between different owners of adjacent DSUs is not a significant regulatory issue because the drainage area associated with unconventional gas wells is so small. They consider a 100 m or 200 m buffer as sufficient to prevent drainage of offsetting DSUs. However, the ERCB should maintain its authority to rule on equity disputes if they arise.

Drilling and Completions—Fracturing

Objective

To understand if unique regulatory requirements for drilling and completing unconventional gas wells are in place, especially for the purpose of groundwater protection.

Issue

Current regulatory requirements protect groundwater and ensure the safe drilling, completion (including stimulation), and abandonment of vertical wells completed in deep or shallow formations. Unconventional gas development extensively uses horizontal drilling and massive hydraulic fracturing of reservoir rock.

Note: The subject of water management is presented as a subsection within the drilling and completion section given the significant amount of information obtained.

Respondents	Comments –Drilling and Completion - Fracturing
British Columbia	Aware of potential split vertical tenure trespass issues caused by vertical fracture propagation beyond the targeted shale zone. The Oil and Gas Commission (OGC) and Ministry of Energy, Mines and Petroleum Resources (MEMPR) are reviewing potential for conflict. Are considering the need to evaluate the potential for fracturing of shale zones that form cap rock to acid gas disposal schemes to jeopardize disposal scheme integrity to determine if regulation is necessary. Believe there is need for increased understanding of shale fracturing. Considerable microseismic monitoring to map hydraulic fractures is being done by operators. OGC sees benefit in having the information submitted and is considering the pros and cons for all parties. Issued a Safety Advisory in May 2010, “Communication During Fracture Stimulation,” in response to a number of incidents where hydraulic fracturing operations were affecting nearby (ranging from 50 to 715 m) ongoing drilling operations and producing wells. The Safety Advisory recommends operators cooperate through monitoring of drilling and completion operations and notification of fracturing within 1000 m of existing wellbores and wells being drilled.
Saskatchewan	Saskatchewan does not have specific regulatory requirements related to hydraulic fracturing of formations, both deep and shallow.
Louisiana	Potential regulatory changes are being investigated in partnership with LSU Department of Petroleum Engineering.
Michigan	The shallowness of the productive Antrim Shale causes concern for the protection of freshwater aquifers. Surface casing must be set to a minimum of 100 ft. below the base of the lowest useable groundwater. In addition, Michigan implemented shallow fracturing requirements with permit conditions for wells drilled directionally through the glacial drift: 2.1*This well will be drilled in an area where the Antrim Formation will likely subcrop below the glacial drift. In order to protect the integrity of the bedrock and surface casing, the following conditions apply to the drilling and completion of this well: Production casing shall be set not less than 50 feet below the shoe of the surface casing and shall be cemented to surface. Fracturing shall be restricted to at least 50 feet below the shoe of the surface casing. The zone between the surface casing shoe and 50' below the shoe may be perforated after all fracturing has been completed*. Exceptions to blow out prevention (BOP) requirements are often granted due to low expected pressures and the shallow nature of the Antrim

Respondents	Comments –Drilling and Completion - Fracturing
	Formation. Use of non-API grade of limited service casing (with an appropriately-calculated safety factor) is allowed because of the low pressures experienced with the Antrim Shale. Allowing the Antrim gas wells to be cased with limited service casing was unique to unconventional gas until summer 2008 when there was a stainless steel pipe shortage It is now allowed in cases, when requested, where low pressures are expected, H_2S is NOT expected, and over-pressured formations are not expected. There are no known or documented damage to legally permitted water wells occurring from a hydraulic fracturing event. There have been reported instances of hydraulic fracturing impacting production of an adjacent hydrocarbon producing well in geologic formations other than Antrim. The Office of Geological Survey does not have regulations to mitigate any possible encroachment effects to hydrocarbon producing wells caused by hydraulic fracturing.
New York	The Draft Supplemental Generic Environmental Impact Statement for high volume hydraulic fracturing of the Marcellus Shale and other low-permeability unconventional resources indicates the probability of fracture fluids reaching an underground source of drinking water from properly constructed wells due to subsequent failures in the casing or casing cement is estimated at less than 2×10^{-8} (fewer than 1 in 50 million wells). The document further states analysis shows that hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers by movement of fracturing fluids out of the target fracture formation through subsurface pathways when certain natural conditions exist.
Oklahoma	Well bore communication has been reported during fracturing between adjacent gas well wellbores. Operators are experimenting with simultaneous fracturing on adjacent horizontal legs to reduce potential interference with other offset wells. There have been no cases of water well contamination resulting from hydraulic fracturing of shale gas zones.
Pennsylvania	Regulatory changes are in progress aimed at protecting public safety and protecting groundwater resources through proper well construction, water supply replacement or restoration, well inspection, gas migration investigation and response and well plugging. The rules will enhance casing design, installation, cementing and integrity testing requirements. Additional rule changes to address various operational and environmental issues associated with Marcellus Shale activity are also being contemplated. Fracturing into other gas well bores is has been observed with reports of communication up to a mile away. Operators are seeing about 13% fluid flowback, of which 60% is being recycled and reused. CBM operators are required to use freshwater when fracturing.
Texas	Communication between gas well wellbores during fracturing operations has been observed in wells as far apart as 2000 ft. There have been no documented instances of water well contamination caused by fracturing the deep shale zones. Typical base of groundwater is at 1500 ft. and top of Barnett Shale is at about 6000 ft. There is no requirement to conduct microseismic monitoring of hydraulic fracturing or submit microseismic data. A new Fracture Rule is being developed for expected release late in 2010 or in 2011. Possible new requirements related to disclosure of hydraulic fluid composition and fracture pathway assessment are under consideration.
Operators	CBM water well testing (in Alberta) needs to be assessed to determine if the requirement is achieving the desired regulatory outcome given the

Respondents	Comments –Drilling and Completion - Fracturing
	cost to the operator In response to well bore communication incidents during fracturing some operators have voluntarily adopted a notification process to off set well owners prior to fracturing.

Drilling and Completions —Water Management

Note: The subject of water management is presented as a subsection with in the drilling and completion section given the significant amount of information obtained.

Respondents	Comments – Water Management
British Columbia	Use of fresh water for hydraulic fracturing is becoming an increasingly important issue as volumes used increase. In August 2010, the Oil and Gas Commission (OGC) issued a report “Oil and Gas Water Use in British Columbia” to provide information to the public on the subject. Opportunities for the use of deep saline water are being explored and at least one shale gas development is accessing a portion of its total water needs from the Debolt saline aquifer. Operators are exploring joint operations. The B.C. Ministry of Environment has overall responsibility for water diversion but OGC has authority to issue short term (12 months or less) permits for fresh water use for hydraulic fracturing. (In 2009, the OGC approved a total of 78.569 million cubic metres of surface water withdrawals for oil and gas use.) Consideration is being given to OGC authority to issue permits for 24 month periods. In August 2010, the OGC suspended previously-approved water withdrawals in the Peace River basin due to severe drought conditions (Water Use Suspension Directive 2010-05). New regulations (under the *Oil and Gas Activities Act*) in B.C. will require a well permit holder to maintain a record of the components of all fracturing fluids that are used in a well for which the well permit holder is responsible. IL OGC-9-07 established requirements for the containment, storage and disposal of fluid returns from hydraulic fracturing operations. Temporary (less than one year) surface pipelines are allowed for water transportation and permitted by OGC.
Saskatchewan	Requirements and methods for handling and disposal of fracture fluids are set in guideline GL 2000-01 – *Saskatchewan Hydraulic Fracture Fluids and Propping Agents Containment and Disposal Guidelines*
Louisiana	Operators are required to report on the source and volume of water used for fracture operations. Groundwater may be used for drilling and for hydraulic fracturing, however if used for fracturing, the groundwater well owner must provide advance notification prior to groundwater withdrawal for fracturing purposes for the agency evaluation and approval. E & P wastewater (produced water) is permitted to be used as an alternative or to supplement to fresh surface water for hydraulic fracture fluid.
Michigan	Experience has been that the majority of fracturing fluid is recovered within 48 hours of initial well flow and is then disposed of in operator-owned brine disposal wells. Fracturing fluid is predominantly composed of fresh water, nitrogen foam, and a proprietary mix of chemicals. All volumes disposed of in a brine disposal well are required to be reported on a monthly basis.

Respondents	Comments – Water Management
	Currently there are no regulations limiting the use of water.
New York	It is estimated that 2.4 million to 7.8 million gallons of water may be used for a multi-stage hydraulic fracturing procedure in a 4 000-foot lateral wellbore. Operators may withdraw water from surface or ground water sources themselves or may purchase it from suppliers. The suppliers may be municipalities with excess capacity in their public supply systems, or industrial entities with wastewater effluent streams that meet usability criteria for hydraulic fracturing. Water may be delivered by truck or pipeline directly from the source to the well pad, or may be delivered by trucks or pipeline from centralized water storage or staging facilities consisting of tanks or engineered impoundments. At the well pad, water is typically stored in 500-barrel steel tanks. Operators have indicated that centralized water storage impoundments will likely be utilized as part of a water management plan. An impoundment could service well pads within a radius of up to four miles, and that impoundment volume could be several million gallons with surface acreage of up to five acres. Fracture fluid and produced water is contained in enclosed systems. Drilling and fracturing fluids are classified as non-hazardous industrial waste and its transportation and disposal is regulated. Marcellus operators are actively researching options where Class II disposal wells and municipal and industrial treatment facilities can be used to manage flow-back water. The primary environmental consideration with respect to disposal wells is the potential for movement of injected fluids into or between potential underground sources of drinking water. Proposed disposal wells require individual site-specific review. Therefore, the potential for significant adverse environmental impacts from any proposal to inject flowback water from high-volume hydraulic fracturing into a disposal well will be reviewed on a site-specific basis with consideration to local geology (including faults and seismicity), hydrogeology, nearby wellbores or other potential conduits for fluid migration and other pertinent site-specific factors.
Oklahoma	Approximately 30 percent of hydraulic fracturing fluid flows back from the formation and is mostly currently hauled to injection wells for disposal. Developing new rules for the design and operation of holding pits for containment of hydraulic fracturing fluid flowback. Large centralized fracturing water recycling facilities are being used with operating lives of five years or longer which require new rules as existing rules cover only temporary facilities. Some brackish water with up to 30 000 ppm chlorides is being used for fracturing fluid make-up. An important concern with fracturing fluid water is bacteria and incompatibility with the shale gas zone resulting in loss of permeability. Most common transportation of water is though “fast lines” (i.e., plastic lines) on surface. Currently no time limits on fast lines. Operators are required to maintain records of fracture fluid chemical composition and produce the records if requested.
Pennsylvania	To date, public concern about use of large volumes of fresh water for the Marcellus Shale development has been limited. The state is heavily industrialized and the volume of water used by the oil and gas industry is small compared with other industrial uses. Shale gas operations have resulted in instances of spillage of fracturing flowback fluid from storage, transportation and in at least one well control incident that has contaminated surface water and land with hydraulic fracturing fluid. Department of Environmental Protection, Bureau of Oil and Gas Management (DEPBOGM) has issued substantial fines against operators for spills. Geology is not favorable for underground injection disposal of fracture fluid flowback so operators often dispose of flowback through sewage treatment facilities to achieve dilution before discharge to surface water. State is developing new Total Dissolved Solids standards for sewage treatment plant discharge to tighten control of this practice. Regulatory changes are in progress aimed at protecting public safety and protecting groundwater resources through proper well construction,

Respondents	Comments – Water Management
	water supply replacement or restoration, well inspection, gas migration investigation and response and well plugging. The rules will enhance casing design, installation, cementing and integrity testing requirements. Additional rule changes to address various operational and environmental issues associated with Marcellus Shale activity are also being contemplated. There is a legal presumption that an operator is responsible for contamination of groundwater if pollution is found within 1000 ft of any activity it has conducted, which the operator must rebut. Most water used for hydraulic fracturing is transported by trucks which have caused considerable road damage and inconvenience to communities affected by the high volumes of truck traffic.
Texas	Use of large quantities (approximately 1 million gallons per fracture stage) of fresh water is a concern in the state, especially during period of drought. There have been localized concerns expressed about freshwater aquifers going dry. Surface and groundwater is generally more plentiful in the East Texas area where the Barnett development is underway. South Texas where the Eagleford shale play is located is more arid, and water use is likely to be a significant concern. The Commission has encouraged the development and use of technology to recycle hydraulic fracture fluids that flow back following completion of the fracturing operation and in 2006 created the Recycling Rule as a mechanism to permit recycling facilities. A small number of recycling operations have been permitted, designed to reclaim as much as 75% of fracture fluid flow back volumes for re-use using distillation and membrane technology. These operations have experienced limited economic success. Operators are experimenting with the use of higher (60 000 ppm of TDS) water to make up hydraulic fracture fluid as means to reduce the use of fresh water. Permits required to use water are issued by the Texas Commission on Environmental Quality. The Texas Water Development Board monitors groundwater and surface water use and forecasts and models water availability. According to a Water Development Board Report, approximately 60 percent of the fresh water sourced for hydraulic fracturing of the Barnett Shale is groundwater. Water is primarily transported by trucks. Storage on the welllsite is in tanks (20 or more) or in lined pits. Operators have requested an expedited process for the approval of storage pits to facilitate movement of fracturing operations from one site to another more quickly. The Commission has not authorized and alternative to current permitting procedures. Some municipalities allow limited amounts of hydraulic fracture flowback fluid to be disposed of through their sewage treatment plants where it is diluted sufficiently to meet standards for discharge to surface water. A potential issue that the Commission is preparing to evaluate is whether traditional disposal zones are adequate to receive the higher than historical rates of injection of fluids resulting from disposal of hydraulic fracturing fluid. The Commission noted that some hydraulic fracture fluid from operations in Louisiana is currently being transported for disposal at Texas injection wells.
Wyoming	The Wyoming Oil and Gas Conservation Commission is the first US jurisdiction to enact regulations (summer 2010) requiring the disclosure of all chemicals used in hydraulic fracturing operations and the identification of all groundwater sources and state-licensed wells in proximity to fracturing operations. Chemical data disclosed to the Commission is maintained as confidential information by the Commission.
Operator Response	Guaranteed timely access to significant volumes of water for hydraulic fracturing are required in order for development to proceed. Shale gas developers require timely access to approximately 15 000-20 000 m^3 of water required per well through temporary diversion licences. Water storage requirements are unique for shale gas development and warrant the creation of separate regulatory requirements that recognize

Respondents	Comments – Water Management
	the significant and different water storage needs for shale gas development, namely storage of large volumes of water (fresh and flowback) on sites, possibly for extended periods of time in order to supply the high injection rates and large total volumes used for large hydraulic fracturing operations. Regulations for temporary water storage do not recognize the unique nature of shale development, particularly at the pilot stage. Temporary water storage regulations should reflect the nature of unconventional development. As an example, hydraulic fracturing operations are a manned undertaking while the present requirements for temporary water storage are for unmanned operations. Use of deeper saline aquifer sources for hydraulic fracturing water is feasible (higher Total Dissolved Solid content may be economically prohibitive) but requires significant capital for high deliverability well, water treatment and sweetening if water is sour as well has high operating costs for lifting water. Currently there is no formal tenure of rights to saline aquifer withdrawal so there is concern regarding protection of rights to the water once capital is invested. Operators are studying possible fracturing flowback recycling options, included reinjection back to the deep aquifer it was sourced from. Temporary above ground pipelines will be needed to transport source water to hydraulic fracturing sites and transport flow back liquids to site for reuse or disposal. Trucking water is a high cost alternative. Under Alberta Environment authority, consider amending the current water regulation schedule 3, s.1 to increase exemptions for dugout and borrow pit water withdrawals.

Landowner and Public Concerns

Objective

To understand what concerns about unconventional gas are being raised by landowners, communities, and the public, how these are considered in the regulatory process, and what actions have been taken by the regulator, other government agencies, or industry to address the concerns.

Issue

In some cases, unconventional gas development may require more concentrated surface infrastructure with potentially longer life, resulting in more surface impact than conventional development. Shale gas development is occurring in areas outside of those that have traditionally seen lots of activity for conventional oil and gas development. As well, there has been public concern about hydraulic fracturing and shallow hydrocarbon development in close proximity to water wells and aquifers.

Respondents	Comments - Landowner and Public Concerns
British Columbia	Use of fresh water for hydraulic fracturing is becoming an increasingly important issue as volumes used increase. In August 2010, the Oil and Gas Commission (OGC) issued the report “Oil and Gas Water Use in British Columbia” to provide information to the public on the subject. Traffic and noise are concerns raised by locals due to the extended duration of drilling and completion activity which can last 24 – 36 months at a pad site. Some concern has been expressed about potential contamination of groundwater by hydraulic fracturing. Concerns are raised by landowners regarding the clearing of land and the level of activity, which is a large change for many that are not used to industry. The OGC provides a Landowners Liaison Officer to help residents understand their rights and has the legal authority to shut down activities or order remedial work if activities are not conducted in accordance with the regulations.
Saskatchewan	Some public raise concerns about CBM development-related issues reported in other jurisdictions. Saskatchewan’s Ministry of Energy and Resources works to identify areas where development could take place and provide the public there with general information that responds to concerns about CBM development. The Ministry also has a FAQ document titled ‘Natural Gas in Coal” viewable on its website.
Louisiana	The primary concern is about the large volumes of water used for hydraulic fracturing and the sustainability of fresh water supplies in the state. Noise levels during drilling and fracturing operations is also of concern to nearby landowners. In 2009, to address issues related to increasing drilling for shale gas in urban areas, the Office of Conservation issued Order No. U-HS for the purpose of establishing reasonable and uniform practices, safeguards and regulations for present and future operations related to the exploration for and production of gas from the Haynesville Shale in urban areas. Order No. U-HS is applicable to wells to be drilled or completed in the Haynesville Shale and located within 750 ft (230 m) of a residence, religious institution, public building or public park in an urban area (as defined in the Order). The Order addresses well setbacks, site fencing and maintenance, dust, vibration, odors, lighting, noise, venting and flaring, discharge, work hours, water use and road use.
Michigan	A major concern is potential for disruption of supply and/or contamination of potable groundwater due to hydraulic fracturing. Surface water withdrawal for fracturing was thought by some to be lowering lake levels but there has been no evidence that this is occurring. Concerns relating to operations include increased traffic, spills on lease sites, noise, intrusion on private property for surface infrastructure and

Respondents	Comments - Landowner and Public Concerns
	property trespass.
New York	Public concern about potential contamination of drinking water supplies in the state has lead to a moratorium on Marcellus Shale gas development.
Oklahoma	Shale gas development is occurring in areas of Oklahoma outside of those that have traditionally seen lots of activity for conventional oil and gas development. This is causing some local concerns because it is not familiar activity. Specific concern about water well contamination caused by hydraulic fracturing has been limited, but the OCC expects interest in this to increase with the media and political attention. Fresh water usage for fracturing has not triggered a lot of concern except during periods of drought in the state. Heavy truck traffic hauling water in and out during fracturing operations triggers complaints about traffic disruptions and road damage.
Pennsylvania	Gas migration linked to faulty well casing and cementing has led to public safety concerns about methane in drinking water supplies. Groundwater and surface water contamination by fracturing fluids is a major concern. Instances of leaking storage pits have contributed to this concern. Potential contamination of useable water by fracturing fluids is on the agenda of several state governments and the US Federal Government. The US EPA is currently conducting hearings to develop terms of reference for further study into the risks of hydraulic fracturing to useable water supplies. In response to public pressure for disclosure of fracturing chemicals, the Department of Environmental Protection – Bureau of Oil and Gas Management (DEPBOGM) has started to publish on its website, detailed listings of hydraulic fracturing solutions being used by various fracturing service vendors working in the Marcellus Shale. Extreme levels of truck traffic associated with hauling water for hydraulic fracturing is disruptive to communities and is causing extensive damage to roadways. Fresh water usage has not been of much concern to date as the volumes used for hydraulic fracturing are still small relative to other industrial use in the state. Spills, light pollution, noise, flaring and air quality are concerns related to shale gas operations in the state.
Texas	Because of the very close proximity of the Barnett Shale play to the densely populated Fort Worth urban area, nuisance issues such as traffic, noise and odors are common. The Railroad Commission has no jurisdiction over these types of concerns and informs the public of this on its website. Municipal governments are developing various ordinances to regulate nuisance issues and generally provide for increased protection of surface owners rights. Some municipal governments are considering the notion of prohibiting the oil and gas industry from operating in their area. Media attention on alleged links between hydraulic fracturing and water well contamination is resulting in increased concern about this from landowners in Texas. Some municipal governments are lobbying for a new Railroad Commission requirement that would require operators to disclose the chemical composition of fracturing fluids used in their areas. There is some concern about the impact of using such large amounts of ground water on other users of these aquifers.
Wyoming	The Wyoming Oil and Gas Conservation Commission is the first US jurisdiction to enact regulations (Summer 2010) requiring the disclosure of all chemicals used in hydraulic fracturing operations and the identification of all groundwater sources and state-licensed wells in proximity to fracturing operations. Chemical data disclosed to the Commission is maintained as confidential information by the Commission.

Environment

Objective

To understand what environmental impacts related to unconventional gas have been encountered and if any new regulatory requirements have been necessary to mitigate them.

Issue

Unconventional gas development has the potential for increased surface disturbance, groundwater impacts related to exploiting shallower gas zones with increased well density and fracturing, and air emissions from increased gathering and processing infrastructure.

Respondents	Comments – Environment
British Columbia	Commission Order 10-15-001 approved the extensive (934,303 hectares) Liard-Besa River Development Scheme as an experimental scheme for development of the Besa River Shale and requires the preparation of Environmental Stewardship Plan to be prepared by scheme area operators. Ministry of Energy, Mines and Petroleum Resources (MEMPR) Information Bulletin 2010EMPR0027-000734 recently introduced “Resource Review Areas” (RRA) across portions (500,000 hectares) of British Columbia’s boreal caribou ranges within which no new natural gas and petroleum tenure will be granted for the next 5 years. In addition to the RRAs, specific habitat areas will be subject to management requirements specified in the new Oil and Gas Activities Act. A moratorium on CBM development in the Flathead River Valley continues pending assessment of potential environmental impacts. Potential environmental issues under consideration include air quality, emissions from sweetening sour fracturing source water, compressor emissions, wildlife management and ecosystem fragmentation challenges.
Michigan	An Antrim Project application might be for several wells, gathering lines, one or more associated production facilities, brine disposal well, roads and plans for handling drill cuttings. An Antrim Project application would include an Antrim Project Environmental Impact Assessment (EQP 7200-21), Project Maps and other project-related information. Other regulatory agencies which Office of Geological Survey may involve include wildlife, wetlands, forestry, fisheries, and remediation and redevelopment professionals for areas with known contamination. Antrim Shale gas production contains CO_2 in increasing proportion as the gas reserves are produced which results in increased venting of CO_2 to atmosphere. Minimizing surface footprint is encouraged to manage cumulative effects and is evaluated through the Antrim Project Environmental Impact Assessment. Air quality is anticipated to be an issue given the emissions associated with compressors and diesel trucks.
New York	2.2Concerns include protection of waterways/waterbodies; drinking water supplies; public lands; coastal areas; wetlands; floodplains; soils; ; intensive timber production areas; significant habitats; areas of historic, architectural, archaeological and cultural significance; clean air and visual 2.3Updating requirements through Draft Supplemental Generic Environmental Impact Statement.
Oklahoma	Developing new ozone standard for potential air pollution issues.

Respondents	Comments – Environment
Pennsylvania	Recognize air pollution and cumulative effects of compressors and diesel engines will be a big issue in the near future.
Texas	Texas Commission of Environmental Quality handles the environmental monitoring of industry and has established permanent air monitoring stations in the Fort Worth area to monitor effects of the Barnett Shale activity on air quality. Issues of concern are flaring and venting, air emissions, water usage, water disposal. The Railroad Commission noted that the Eagleford Shale gas is more liquids rich than the Barnett Shale and also contains hydrogen sulphide (400 – 500 ppm) in some areas which may result in some increase sulphur emissions to atmosphere.
Operator	Year round surface access is required for shale gas development. Believe that habitat protection can be achieved while permitting year round access through the Implementation of industry best practice for minimal impact. Current surface land access constraints due to multiple timing windows for species at risk (grizzly and caribou) will be very problematic for shale gas development. Operational and cost advantages associated with multiwell pads will help to minimize number of surface sites, roads, and pipeline corridors although each surface site will be large (100 000 + m^2). A coordinated approach for approvals would minimize surface disturbance by allowing for coordination of drilling operations. Shift away from traditional approach to evaluating well spacing applications would enable operators to go into an area once and develop to desired well density rather than going in multiple times as production history proves up the need for incremental increases in well density. Alignment of GOA objectives across ministries Energy, Sustainable Resource Development and Environment. Flaring –revise Directive 60 requirements to accommodate pad drilling approach. Consider Bureau of Land Management approach to development in US which is to allow development of a specified area or block for a specified period of time after which access is restricted and a new area is opened up for development for a specified time. Regulation of environmental impacts of unconventional gas development should focus on groundwater protection and surface foot print.

Regulatory Processes

Objective

To understand if regulators have modified regulatory processes, such as approvals or data submission requirements, to accommodate unconventional gas development.

Issue

Does the development of unconventional gas reserves require a different format for regulatory processes, such as approvals and data collection, in order to be efficient?

Respondents	Comments – Regulatory Processes
British Columbia	Considering possible changes to well licensing processes to streamline application and approval of multiple wellbores drilled from a single surface pad. “Good Engineering Practice” (GEP) applications are filed to request variation from standard well spacing. Operators determine optimal well density to recover the resource and make an application. GEP approvals are evaluated and based on the requested well density, but do not specify a well density in the approval. Aware of potential split vertical tenure trespass issues caused by vertical fracture propagation beyond the targeted shale zone. The Oil and Gas Commission (OGC) and Ministry of Energy, Mines and Petroleum Resources (MEMPR) are reviewing potential for conflict. Issued a Safety Advisory in May 2010, “Communication During Fracture Stimulation” in response to a number of incidents where hydraulic fracturing operations were affecting nearby (ranging from 50 m to 715 m) ongoing drilling operations and producing wells. The OGC recommends operators cooperate through monitoring of drilling and completion operations and notification of fracturing within 1000 m of existing wellbores and wells being drilled. Commission Order 10-15-001 approved the extensive (934 303 hectares) Liard-Besa River Development Scheme as an experimental scheme for development of the Besa River Shale. The order waives standard well spacing in the development area, provides for a 3-year well data confidentiality period, and requires the preparation of Environmental Stewardship Plan to be prepared by scheme area operators. Experimental scheme status has been requested and granted in come cases to provide extended confidentiality for well data of 3 years instead of the standard 1-year period. OGC notes that the Montney Shale development in B.C. has taken place for the most part under the standard 1-year data confidentiality provisions and OGC does not view that the standard data treatment has hindered the Montney development. A challenge of administering experimental scheme status is determining an appropriate end of activity considered “experimental”. MEMPR Information Bulletin 2010EMPR0027-000734 recently introduced “Resource Review Areas” (RRA) across portions (500,000 hectares) of British Columbia’s boreal caribou ranges within which no new natural gas and petroleum tenure will be granted for the next 5 years. In addition to the RRAs, specific habitat areas will be subject to management requirements specified in the new Oil and Gas Activities Act.
Louisiana	In 2009 the Office of Conservation issued Order No. U-HS for the purpose of establishing reasonable and uniform practices, safeguards and regulations for present and future operations related to the exploration for and production of gas from the Haynesville Shale in urban areas. Order No. U-HS is applicable to wells to be drilled or completed in the Haynesville Shale and located within 750 ft. (230 m) of a residence, religious institution, public building or public park in an urban area (as defined in the Order). The Order addresses well setbacks, site fencing and maintenance, dust, vibration, odors, lighting, noise, venting and flaring, discharge, work hours, water use and road use.

Respondents	Comments – Regulatory Processes
	Adjusted requirements generally to adapt for the use of horizontal wells and reduced well spacing. Allowance for the creation of larger units with multiple wells per unit, standardized definitions for productive intervals for unitization purposes has been introduced. Well spacing rules include a 330ft buffer around the DSU which can be adjusted to create units and, for shale gas, no well can be closer than 660 ft from any other unit well (interwell distance). For tight gas, conventional rules apply which specify a 2000ft interwell distance. For CBM, there is no interwell distance. Implemented requirements for large units with a multiplicity of wells allowed to facilitate development and completion requirements of the horizontal well laterals.
Michigan	Some state mineral leases require the use of a common drilling pad in which several directional wells are drilled, in order to minimize surface waste. Horizontal drilling is also encouraged. Office of Geological Survey requires companies to submit permit applications on a project basis (Antrim Project), rather than permitting on a well-by-well basis. An Antrim Project application might be for several wells, gathering lines, one or more associated production facilities, brine disposal well, roads and plans for handling drill cuttings. An Antrim Project application would include an Antrim Project Environmental Impact Assessment (EQP 7200-21), project maps and other project-related information. Operators may apply for a Uniform Spacing Plan (USP) to obtain relief from standard well spacing for Antrim Shale wells only. A USP is a pooled area, larger than the standard drilling unit. A USP promotes efficient and orderly development of Antrim Shale gas by limiting vertical well density to a maximum of 1 well per 80 acres but providing for as many horizontal drain holes drilled from each vertical well location as deemed appropriate by the operator without further application across an area that is larger than a single 80-acre drilling unit with horizontal drain hole locations limited only by a 330 foot setback from the boundary of the USP. By Special Order, drilling of “Antrim Twin Wells” (a second well drilled in a single drilling unit) is permitted to enable production from a second distinct reservoir unit (upper zone) present in the Antrim Shale. In many areas, the pressure of the lower Antrim Shale zone has been depleted by years of production and now the pressure differential between the upper and lower reservoir units is too great to achieve efficient production from both zones if they are commingled in a single wellbore. A horizontal drain hole is considered to be a completion technology and a new horizontal drain hole drilled from an existing vertical well may be added by applying for a “Change of Well Status” rather than a permit to drill a new well. This process existed prior to the Antrim Shale development as well but the modification made since the Antrim development is to review these applications for conformance with well spacing requirements.
New York	Creating the “Supplemental Generic Environmental Impact Statement” requirements for development in the Marcellus Shale.
Oklahoma	Modifying DSU in size and shape to accommodate horizontal drilling. Exceptions to standard well spacing are routinely granted.
Pennsylvania	Regulatory changes are in progress aimed at protecting public safety and protecting groundwater resources through proper well construction, water supply replacement or restoration, well inspection, gas migration investigation and response and well plugging. The rules will enhance casing design, installation, cementing and integrity testing requirements. Additional rule changes to address various operational and environmental issues associated with Marcellus Shale activity are also being contemplated. The Bureau is required by legislation to issue a well licence within 45 days of receiving the 1-page application.
Texas	Although well permitting is done through the Railroad Commission’s head office, well completion reports for every well drilled in a field are filed with the district office associated with the discovery well for the field. The very high activity levels in the Barnett play overwhelmed the district office responsible to process the well completion reports. The Commission is moving towards online filing to better distribute work volume among available Commission resources.

Respondents	Comments – Regulatory Processes
	For the Eagleford Shale play, the Commission is considering holding hearings to consolidate field rules for some 38 fields into a single set of field rules for the entire Eagleford Shale play. A potential complication to this consolidation is that some areas of the Eagleford play are sour and if consolidated, the entire play would be subject to hydrogen sulphide production rules.
Operator Response	Current regulations require approvals on a well-by-well (or pipeline-by-pipeline) basis. Consideration should be given to issuing “project-level” approvals for shale gas development. Consultation requirements should be adapted to project level approvals but individual stakeholder objections or interventions should not impact an entire program. Clear rules regarding how stakeholder objections or interventions would affect program level approvals are required. Alberta’s First Nations Consultation Guidelines should be updated such that a more formal / strict approach to Aboriginal consultation is defined such as in British Columbia, including set timelines, consistent process, adequate funding for government to ensure capacity in communities to address consultation requirements, and a consistent determination or standard for the adequacy of consultation. Pre-drilling approval of pipelines is desirable and appropriate for shale gas development. As wells are drilled to exploit a known shale gas resource, there is virtually no possibility of non-commercial wells so the need the pipeline is certain. Pre-built pipelines would enable the earliest possible tie-in of wells to reduce flaring, allow for earlier and better production evaluation, and connect the gas to market faster. Regulatory requirements for blanket flare permits are onerous and need to be simplified for shale gas developments. A “blanket permit” should be adopted to cover multiple wells on a pad. Also, sulphur emission requirements should change, air dispersion modeling should be appropriate to the entire pad and the rules governing what constitutes “complex modeling” should be relaxed. Emergency response plan (ERP) approvals should be issued for each pad, rather than for each well on the pad. ERCB regulations should focus on public safety, environmental protection and resource development in the public interest. Downspacing should be permitted without having to prove that it is necessary as it can be challenging obtaining the right data to support a downspacing application. The current application process for special spacing is too time consuming and requesting incremental increases to well density based on production history does not match well with unconventional gas development plans to drill numerous wells (at increased well density) early on. The unique nature of unconventional gas development should be recognized and well spacing should allow for a minimum of eight wells per DSU as standard spacing. Operators should be allowed to commingle all shale zones within a play without conditions or approval process. Both downspacing and commingling is required because the nature of the resource is such that more wells and more completions within the wellbore are required for the resource to be economical. Timely approvals are critical to avoid impacting unconventional project economics. CBM water well testing needs to be assessed to determine if the requirement is achieving the desired regulatory outcome given the cost the operator. Some current regulatory requirements hinder the efficiencies to be gained by drilling multiple wells from a single pad. For example, requirements for setting conductor pipe (OGCR 6.080(3)) should be modified to reduce rig waiting time when drilling subsequent wells on a pad. Shale gas developers require timely access to approximately 15 000-20 000 m^3 of water required per well through temporary diversion licences. Water storage requirements are unique for shale gas development and warrant the creation of separate regulatory requirements that recognize the significant and different water storage needs for shale gas development, namely storage of large volumes of water (fresh and flowback) on sites, possibly for extended periods of time in order to supply the high injection rates and large total volumes used for large hydraulic fracturing operations. Regulations for temporary water storage do not recognize the unique nature of shale development, particularly at the pilot stage.

Respondents	Comments – Regulatory Processes
	Temporary water storage regulations should reflect the nature of unconventional development. As an example, hydraulic fracturing operations are a manned undertaking while the present requirements for temporary water storage are for unmanned operations. Use of deeper saline aquifer sources for hydraulic fracturing water is feasible (higher Total Dissolved Solid content may be economically prohibitive) but requires significant capital for high deliverability well, water treatment and sweetening if water is sour as well has high operating costs for lifting water. Currently there is no formal tenure of rights to saline aquifer withdrawal so there is concern regarding protection of rights to the water once capital is invested. Temporary above ground pipelines will be needed to transport source water to hydraulic fracturing sites and transport flow back liquids to site for reuse or disposal. Trucking water is a high cost alternative. An amendment by Alberta Environment of the current regulation schedule 3 s.1 of the water regulation for exemption increase for water withdrawals from dugout and borrow pits would facilitate the use of these as water supplies for hydraulic fracturing. Extended data confidentiality should be provided for shale gas development, for periods of 3 – 4 years by granting experimental scheme status to shale gas projects. Suggestions include a revision to the existing experimental scheme provisions by creating a ‘shale gas’ experimental scheme category and a standard experimental shale gas pilot application form or application process with relevant information requirements.

Information Collection and Dissemination

Objective

To understand what types of information about unconventional gas are being collected in other jurisdictions and what they are used for.

Issue

Characteristics of unconventional gas reservoirs, such as very low permeability, low flow rates, and development with no segregation between zones, make the collection of traditional production and pressure data onerous or impractical.

Respondents	Comments – Information Collection and Dissemination
British Columbia	Traditional reserves estimation methods such as volumetric and material balance have been used to date, but are also considering a more statistical approach which may lead to revised information requirements. In recognizing costs associated with data collection and submission, the OGC is considering reducing the frequency and coverage while focusing on higher quality, relevant data. "Special Data Wells" would earn extended confidentiality in exchange for collecting and submitting data such as core, petrophysical and micro-seismic and other deemed to be of high value for determining most efficient reservoir development practices. Granting of experimental scheme status has been used to provide extended confidentiality for well data of 3 years instead of the standard 1-year period. This has been difficult to manage with respect to operators continuing to drill wells as part of the experimental scheme but which the OGC might consider to be developmental. OGC notes that the Montney Shale development in B.C. has taken place under the standard 1-year data confidentiality provisions and OGC does not view that the standard data treatment has hindered the Montney development. Believe there is need for increased understanding of shale fracturing. Considerable microseismic monitoring to map hydraulic fractures is being done by operators. OGC sees benefit in having the information submitted and is considering the pros and cons for all parties.
Saskatchewan	Data submission requirements are set out in the Oil and Gas Conservation Act and are the same as for conventional oil and gas. Data confidentiality period is 1 year for a well outside of a defined pool boundary or 30 days for a well drilled within a defined pool.
Louisiana	Noted that it would be useful to have increased availability of individual well production and other performance data, fracturing extent and geometry information, reserves estimates and reservoir characteristics in order to be able to fully assess proposed well spacing and completion plans.
Texas	Well logs can be confidential for 2 years with an option for the operator to request an additional year of confidentiality. All other information once given to Railroad Commission is considered public.
Operators	Requirements for pressure and flow data, and how that data is being used should be reviewed. Traditional material balance methods for estimating reserves are not reliable for unconventional gas because the pressure data gathered in very low permeability reservoirs is neither accurate nor representative of reservoir pressure. Deterministic approaches to estimating reserves do not work so regulators should move toward more statistical methods. Current ERCB requirements for shale control wells (i.e. data collection, drilling/rock samples, logging, pressure and flow testing) are based on coal bed methane development and therefore not appropriate for shale development given the unique nature of the shale resource and its reservoir properties. The need for certain data is recognized and the ERCB should identify specific new shale gas data collection requirements. Regulators need to be more cognizant of the cost burden of data collection requirements as a shale control wells can cost up to $3-4M each. Specific pressure testing requirements that have limited value are initial pressure information gathered from commingled zones, and 14-day build-

Respondents	Comments – Information Collection and Dissemination
	up tests in tight reservoirs. Extended data confidentiality should be provided for shale gas development, for periods of 3 – 4 years by granting experimental scheme status to shale gas projects. Suggestions include a revision to the existing experimental scheme provisions by creating a ‘shale gas’ experimental scheme category and a standard experimental shale gas pilot application form or application process with relevant information requirements. Sufficient data on Horseshoe Canyon coal gas content has already been gathered to enable reasonable estimating of OGIP so the requirement to gather more should be discontinued. Gas Desorption testing for shale as currently specified by the ERCB will not yield useful information for estimating OGIP for shale gas. Onerous data collection requirements imposed early in the resource evaluation cycle can be cost prohibitive when potential development has not even yet been confirmed.

Appendix 2 Jurisdictional Survey

ERCB Unconventional Gas Regulatory Framework—Jurisdictional Survey

Jurisdiction: [Jurisdiction]
Respondent: [Agency/Department]
Primary Contact: [Name of Primary Contact]
Telephone: [Telephone]
E-mail: [E-mail]

Introduction

The goal of this survey is to gain an understanding of how unconventional gas is regulated in your jurisdiction, what challenges you face, and what plans you have to address issues associated with unconventional gas development. The ERCB does not have a formal definition of unconventional gas; for the purpose of completing this survey, please consider unconventional gas to include gas produced from shale, coal seams, and very low-permeability reservoir rock that requires the use of extensive stimulation techniques to achieve economic production rates.

We have sent this survey to a number of jurisdictions. To facilitate an exchange of information on regulatory issues and best practices related to unconventional gas, the ERCB will undertake to consolidate the information collected and make it available to each survey respondent. Thank you in advance for your contribution.

Instructions

This survey may be completed and submitted in written form using the Microsoft Word file on the enclosed CD or conducted by way of a telephone interview. If preparing written responses using the Microsoft Word file, feel free to insert any relevant links. Where appropriate, please provide responses specific to each type of unconventional resource: shale gas, coalbed methane, and tight gas. If any subject areas of this survey are the responsibility of a different government agency or department, please assist us by providing appropriate contact information if possible. If responding to the survey by way of a telephone interview, please provide an appropriate contact to arrange the details of the interview. ERCB staff will prepare written responses to the survey based on the interview.

If you have questions regarding the purpose or content of this survey, please contact Brad Hubbard by telephone at 403-297-8502 or by e-mail to brad.hubbard@ercb.ca. Completed surveys using the Microsoft Word file may be submitted by e-mail to the same e-mail address or by post to

Brad Hubbard
Energy Resources Conservation Board
640 – 5 Avenue SW
Calgary, Alberta T2P 3G4
Canada

1 General

Objective

To understand the issues regarding development of unconventional gas in other jurisdictions.

Information Requested

1.1 What have been the most important challenges presented by unconventional gas development in your area, and how have you addressed these?

- For coalbed methane
- For shale gas
- For tight gas

1.2 What emerging issues do you see that you will need to address?

- For coalbed methane
- For shale gas
- For tight gas

1.3 What changes to regulatory requirements or processes have you made specifically to facilitate the development of unconventional gas?

- For coalbed methane
- For shale gas
- For tight gas

1.4 What do you consider to be the most pressing need for enhanced knowledge or understanding to ensure optimal development of the unconventional gas resource in your jurisdiction?

- For coalbed methane
- For shale gas
- For tight gas

2 Resource Appraisal and Reserves

Objective

To understand resource appraisal and reserves determination approaches and data requirements for unconventional gas resources in other jurisdictions.

Background

The ERCB has a mandated responsibility to undertake appraisal of Alberta’s oil and gas resources. For conventional oil and gas, the ERCB administers comprehensive requirements to collect geological and reservoir engineering data and applies deterministic, pool-specific reserves analysis procedures.

Issue

Initial steps have been taken to realign data requirements for well testing (pressure and flow) and unsegregated production and analysis procedures for resource/reserve assessments, but ongoing practical problems persist in achieving the right balance and procedures to appraise the unconventional gas resource potential and reserves in Alberta.

Information Requested

2.1 Describe how you define and/or categorize resources and reserves.

- For coalbed methane
- For shale gas
- For tight gas

2.2 Describe your methodology for estimating in-place and recoverable reserves.

- For coalbed methane
- For shale gas
- For tight gas

2.3 Describe what geological and engineering data you rely on for estimating in-place and recoverable reserves, how the data are accessed, and any relevant regulatory requirements.

- For coalbed methane
- For shale gas
- For tight gas

2.4 What types of pressure data, if any, do you rely on for reserves determination, and what issues have you encountered with obtaining the data?

- For coalbed methane
- For shale gas
- For tight gas

2.5 Describe the current degree of certainty with estimates of in-place and recoverable reserves and how much these estimates have varied since unconventional gas development commenced.

- For coalbed methane
- For shale gas
- For tight gas

3 Reservoir Development

Objective

To understand how other jurisdictions maximize resource recovery, promote orderly and efficient development, and provide for equity among owners.

Background

Various ERCB requirements derive from mandated responsibilities to achieve maximum resource recovery and efficient and orderly development and to provide for equity among mineral owners. These requirements were designed for conventional oil and gas pools.

Issue

There is a need to develop efficient regulatory processes that facilitate the development of unconventional gas reservoirs, such that resource recovery is not jeopardized, development is orderly and efficient, and equity is provided for.

Information Requested

3.1 Describe your regulatory requirements and processes intended to maximize unconventional gas recovery and how these might differ from requirements for conventional gas.

- For coalbed methane
- For shale gas
- For tight gas

3.2 Describe your regulatory requirements and processes intended to promote efficient and orderly unconventional gas development and how these might differ from requirements for conventional gas.

- For coalbed methane
- For shale gas
- For tight gas

3.3 Describe your regulatory requirements and processes intended to provide for equity among different mineral owners in a common pool, and how these might differ for conventional and unconventional gas.

- For coalbed methane
- For shale gas
- For tight gas

3.4 Describe how well spacing is changing with the development of unconventional gas, how well spacing is regulated, and the criteria used to determine appropriate spacing.

- For coalbed methane
- For shale gas
- For tight gas

4 Drilling and Completion Operations

Objective

To understand if extraordinary regulatory requirements for drilling and completing unconventional gas wells are in place, especially for the purpose of groundwater protection.

Background

The ERCB is responsible to ensure the use of safe and efficient drilling and completion practices that protect the environment.

Issue

Regulatory requirements are in place that protect groundwater and ensure the safe drilling, completion (including stimulation), and abandonment of vertical wells completed in deep or shallow formations. Unconventional gas development extensively uses horizontal drilling and massive hydraulic fracturing of reservoir rock.

Information Requested

4.1 Describe drilling and completion regulatory requirements that are unique to unconventional gas.

- For coalbed methane
- For shale gas
- For tight gas

4.2 Describe regulatory requirements related to hydraulic fracturing of formations, both deep and shallow.

- For coalbed methane
- For shale gas
- For tight gas

4.3 Describe regulatory requirements related to water use for fracturing fluid, fracturing fluid composition, and handling reproduced fracturing fluids.

- For coalbed methane

- For shale gas
- For tight gas

4.4 Describe any documented occurrences of damage to a water well or existing oil or gas production well caused or suspected to have been caused by hydraulically fracturing a new unconventional gas well, and explain what mitigation measures are in place.

- For coalbed methane
- For shale gas
- For tight gas

4.5 Describe any occurrences where fracturing caused problems to wells or aquifers above or below the formation targeted for fracturing.

- For coalbed methane
- For shale gas
- For tight gas

4.6 Describe well plugging requirements and any issues associated with plugging wells that have been subjected to massive hydraulic fracturing or associated with long-reach horizontal wells.

- For coalbed methane
- For shale gas
- For tight gas

5 Landowner/Public Concerns

Objective

To understand what concerns about unconventional gas are being raised by landowners, communities, and the public, how these are considered in the regulatory process, and what actions have been taken by the regulator, other government agencies, or industry to address the concerns.

Background

The ERCB is responsible for ensuring that development of Alberta's energy resources is done in a way that is in the best interest of the public. The ERCB must ensure that parties that may be directly and adversely affected by an approval have an opportunity to learn the facts of a proposed energy development and have their concerns considered by the ERCB. The ERCB is required to balance the local impacts of energy development with benefits to a broader public.

Issue

In some cases, unconventional gas development may require more concentrated surface infrastructure with potentially longer life, resulting in more surface impact than conventional development. As well, there has been public concern about hydraulic fracturing and shallow hydrocarbon development in close proximity to water wells and aquifers.

Information Requested

5.1 Describe the types of concerns being raised by landowners, communities, and interest groups.

- For coalbed methane
- For shale gas
- For tight gas

5.2 How are these concerns considered in the regulatory process?

- For coalbed methane
- For shale gas
- For tight gas

5.3 What measures are being implemented to mitigate the concerns being raised?

- For coalbed methane
- For shale gas
- For tight gas

5.4 What communication tools are used, and by whom, to communicate factual information about unconventional gas development and the issues being raised?

- For coalbed methane
- For shale gas
- For tight gas

6 Environmental Issues

Objective

To understand what environmental impacts related to unconventional gas have been encountered and if any new regulatory requirements have been necessary to mitigate them.

Background

The ERCB is responsible for assessing and regulating the effects of oil and gas development on the environment and controlling pollution.

Issue

Unconventional gas development has the potential for increased surface disturbance, groundwater impacts related to exploiting shallower gas zones with increased well density and fracturing, and air emissions from increased gathering and processing infrastructure.

Information Requested

6.1 Describe what are considered to be important environmental issues related to unconventional gas development in your jurisdiction and how you are addressing these issues.

- For coalbed methane
- For shale gas
- For tight gas

6.2 Describe what issues need future work and what plans you have in this regard.

- For coalbed methane
- For shale gas
- For tight gas

7 Regulatory Processes

Objective

To understand if regulators have modified regulatory processes, such as approvals or data submission requirements, to accommodate unconventional gas development.

Background

The ERCB's regulatory processes for approvals and data submission are comprehensive and were developed to regulate conventional oil and gas.

Issue

Does the development of unconventional gas reserves require a different format for regulatory processes, such as approvals and data collection, in order to be efficient?

Information Requested

7.1 If you have modified your approval processes to accommodate unconventional gas development, please describe how.

- For coalbed methane
- For shale gas
- For tight gas

7.2 If you have modified your data collection requirements or processes to accommodate unconventional gas development, please describe how.

- For coalbed methane
- For shale gas
- For tight gas

7.3 If you have modified your compliance assurance processes to accommodate unconventional gas development, please describe how.

- For coalbed methane
- For shale gas
- For tight gas

8 Information Collection and Dissemination

Objective

To understand what types of information about unconventional gas are being collected in other jurisdictions and what they are used for.

Background

The ERCB is responsible for the collection, retention, and dissemination of information regarding energy resource development in Alberta. Requirements exist for well licensees to gather and submit certain types of geological and reservoir data at the time of drilling a well and during its operating life. ERCB requirements also specify that all data collected by a well licensee must be submitted to the ERCB. The ERCB uses the collected data for various regulatory processes, while also fulfilling its information dissemination mandate by making the data publicly available, largely for use by industry.

Issue

Characteristics of unconventional gas reservoirs, such as very low permeability, low flow rates, and development with no segregation between zones, make the collection of traditional production and pressure data onerous or impractical.

Information Requested

8.1 If you have modified data submission requirements to accommodate unconventional gas development, please describe how.

- For coalbed methane
- For shale gas
- For tight gas

8.2 Describe what you believe is critical data and how you use that data to effectively manage the development of the resource?

- For coalbed methane
- For shale gas
- For tight gas

8.3 Describe your rules concerning the confidentiality of industry-submitted data and whether the confidentiality of unconventional gas data is handled differently from that of conventional resource data?

- For coalbed methane
- For shale gas
- For tight gas

8.4 Explain how the development of the resource benefits from or is hindered by the availability of data to the regulator and industry?

- For coalbed methane
- For shale gas
- For tight gas

9 Other

Please comment on any additional regulatory or other issues related to unconventional gas development that are important in your jurisdiction.

- For coalbed methane
- For shale gas
- For tight gas