Shale Gas in British Columbia

Risks to B.C.'s water resources

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Contents

1. Introduction

British Columbia has been extracting natural gas for half of a century but until recently, conventional wisdom held that the province's economic gas reserves would be significantly depleted by 2020; the readily accessible gas was running out and other reserves were either too remote or too costly to extract. That notion has been challenged in the past several years because the costs of extracting hard-to-access sources of gas, notably shale gas, have dropped significantly. The impacts are far-reaching, as it is now known that B.C. is located on top of gas reserves that are significant not only provincially but also on a continental scale.

Shale gas is an unconventional type of gas, with reserves trapped in geological formations that make it difficult to extract.[1] The reservoir characteristics of conventional gas are such that the gas flows readily from the formation to a well. However, unconventional gas extraction relies upon a combination of techniques that were not technically or economically feasible in the past.[2] The most important of these techniques are:

1. Hydraulic fracturing, which involves injecting pressurized water, gases, chemicals and sand into gas wells to break apart the rock and allow the gas to flow more easily; and
2. Directional drilling, which allows multiple wells to be drilled from a single well pad.

B.C.'s shale gas reserves are found in the northeast, for which most drilling activity has been concentrated in two main deposits: the Montney Basin near Dawson Creek, and the Horn River Basin near Fort Nelson.[3] According to projections from the Canadian Association of Petroleum Producers (CAPP), production from Horn River and Montney Basins could account for 22% of North American shale gas production by 2020 (see Figure 1). The combined 52 billion cubic metres per year (5 billion cubic feet per day — labeled Bcf/d in Figure 1) that is forecast to be produced the Horn River and Montney Basin in 2020 is equivalent to 70% of all the gas that was used in Canada in 2010.[4]

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[1] Coalbed methane is another form of unconventional gas development. For more information, see: West Coast Environmental Law, "Coalbed Methane: A citizen's guide," May 2003, http://www.wcel.org/resources/publication/coalbed-methane-citizens-guide

[2] These individual techniques are sometimes mistakenly referred to as new, but it is the industry's combined abilities to use them at scale and with relatively low cost that has made shale gas economically attractive for producers.

[3] In some publications, the Montney Basin is referred to as tight gas, which is another type of unconventional natural gas. However, unlike typical tight-gas plays, the natural gas in the Montney is sourced from its own organic matter, which is more typical of shale gas. For simplicity, and following the approach used in the National Energy Board's comparison of Canadian shales, this report characterizes the Montney Basin as shale gas.

[4] Canadian Gas Association, "Natural Gas Sales and Exports" found at: www.cga.ca/resources/gas-stats/

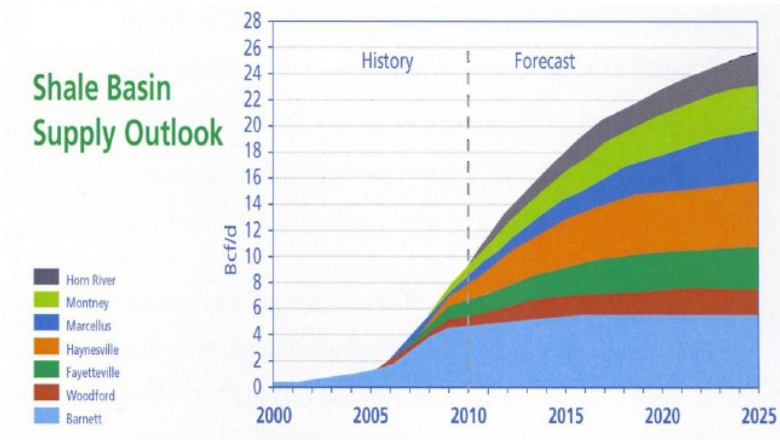

Figure 1 — Projected gas extraction for Canadian and U.S. shale gas reserves. [5]

The shift to shale gas in North America is already well underway. The Barnett Shale in Texas has been subject to hydraulic fracturing and gas extraction since the late 1990s. Likewise, companies have begun extracting gas from the Marcellus Shale, which is located underneath the states of New York, Pennsylvania, Ohio and West Virginia.

While a shift to shale gas began relatively recently in B.C., these sources still accounted for as much as 39% of the province's natural gas production in 2008, predominantly from the Montney Basin.[6] The economic potential of exploiting the province's shale gas reserves has been well documented. As an illustration, the province is counting on $1.8 billion in revenue from gas royalties and leases in 2013/14 — four per cent of forecasted provincial revenues.[7]

Jurisdictions with shale gas reserves are clearly attracted to the potential economic benefits that the resource offers, however, in some regions health and environmental concerns are beginning to dominate the debate, particularly because of potential contamination of ground and surface water resources. Quebec[8], Maryland[9], South Africa[10] and France[11] have all recently placed temporary or indefinite moratoriums on hydraulic fracturing until the risks are better understood.

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[5] Canadian Association of Petroleum Producers *"Canada's Shale Gas,"* February 2010, slide 11, www.capp.ca/GetDoc.aspx?DocID=165107&DT=PDF

[6] BC Ministry of Energy Mines and Petroleum Resources, "Shale Gas Activity in British Columbia: Exploration and Development of BC's Shale Gas Areas,", Presentation to the 4th Annual Unconventional Gas Technical Forum, April 8, 2010, slide 7, www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/C%20Adams.pdf

[7] Government of British Columbia, "B.C. Government Budget and Fiscal Plan, 2011/2012 – 2013/2014," February 15, 2011, charts 1.5 and 1.7, http://www.bcbudget.gov.bc.ca/2011/bfp/2011_Budget_Fiscal_Plan.pdf

[8] Développement durable, Environnement et Parcs, "Développement durable de l'industrie des gaz de schiste au Québec," 2011, http://www.mddep.gouv.qc.ca/communiques_en/2011/c20110308-shale-gas.htm

[9] Maryland General Assembly, "House Bill 852," 2011, http://mlis.state.md.us/2011rs/billfile/hb0852.htm

[10] S. Tavanger, "South Africa imposes fracking moratorium," *Platts Energy Week,* April 25, 2011, http://plattsenergyweektv.com/story.aspx?storyid=147836&catid=293

[11] T. Patel, "The French Public Says No to '*Le Fracking*'," *Bloomberg Businessweek*, March 31, 2011, http://www.businessweek.com/magazine/content/11_15/b4223060759263.htm

The United States Environmental Protection Agency is also undertaking a major study to understand the impacts of hydraulic fracturing.[12]

Health and environmental concerns from gas development are not new to B.C., where the northeast of the province has lived with oil and gas development for over 50 years. There have been long-standing concerns about gas development fragmenting the provincial landscape and endangering species that rely on those ecosystems (e.g., boreal caribou).[13] Numerous concerns have also been raised about the potential health impacts of sour gas leaks, including a recent call for a public health inquiry to investigate whether current regulation of oil and gas development adequately protects public health.[14] The call for that inquiry was supported by First Nations, landowners, and a range of organizations.

Depending on the pace and scale of development, shale gas extraction could exacerbate these concerns. It also raises two additional environmental concerns that have received limited attention in B.C. to date:

- **Water Impacts**. Hydraulic fracturing typically requires large volumes of water, placing additional stress on fresh water systems. Further, the water used for fracturing is contaminated through the process and cannot be returned to fresh water systems.
- **Climate impacts**. Extracting and processing natural gas produces greenhouse gas (GHG) emissions, with the total accounting for 21% of B.C.'s emissions (13.3 million tonnes).[15] Proposed increases in production combined with higher levels of emissions from an equivalent volume of shale gas (relative to conventional sources) will make it increasingly difficult, or impossible, for B.C. to meet its emissions reductions objectives.[16]

Water impacts are the focus of this report.

A dialogue regarding the risks to water resources from shale gas extraction fits the current context in which British Columbians strongly support better provincial protection of water

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[12] The first stage of the EPA's work will be completed in late 2012 and is described in their draft study plan — Environmental Protection Agency, "Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources", February 2011. Available at: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/HFStudyPlanDraft_SAB_020711-08.pdf

[13] For example: Forest Practices Board, "A Case Study of the Kiskatinaw River Watershed — an Appendix to Cumulative Effects: From Assessment towards Management," 2011, p. 9 and Appendix 2, http://www.fpb.gov.bc.ca/SR39_CEA_Case_Study_for_the_Kiskatinaw_River_Watershed.pdf

[14] Letter from University of Victoria Environmental Law Centre on behalf of the Peace Environment and Safety Trustees Society, February 2, 2011, (accessed March 29, 2011), http://www.elc.uvic.ca/documents/11%2002%2002%20Ltr%20to%20Hansen%20re%20Inquiry%20(final%20and%20SIGNED).pdf

[15] Calculated from Table 15-20 from Part 3 of Environment Canada's National Inventory Report: 1990 to 2009 — United Nations Framework Convention on Climate Change (UNFCCC), "National Inventory Submissions 2011," Canada, http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5888.php

[16] Shale gas in B.C. results in higher levels greenhouse gas emissions than conventional gas predominantly because of the high percentage of formation carbon dioxide in the Horn River basin.

resources. A poll released late in 2010 found that 91% of British Columbians consider freshwater to be B.C.'s most precious resource and 94% favour making the protection of nature and wildlife a priority in any changes to B.C.'s Water Act.[17] The province's Water Act, among other things, establishes the permitting regime for water uses in B.C. — including the demands of the oil and gas industry. The B.C. government has started to respond to those public priorities by endeavoring to improve the way that water resources are protected and managed in the province. A major part of that commitment is the effort to modernize the Water Act.[18]

This report is laid out as follows:

- Section 2 explores the known and potential impacts to water resources from shale gas extraction in B.C. While this report attempts to draw on the most recent research available it is important to acknowledge that many knowledge gaps still exist and that there is considerable uncertainty and variability in the data.
- Section 3 discusses the current regulatory environment in B.C. for water use and disposal in the oil and gas industry. In many cases, B.C.'s approaches to resource management and environmental protection are not fully equipped to deal with the new pressures introduced by the anticipated pace of shale gas development.
- Section 4 provides an overview of regulatory developments in other jurisdictions attempting to manage shale gas development and respond to development proposals.
- Section 5 recommends ways in which B.C. can improve its planning and regulatory framework for shale gas development to provide better protection for the province's water resources.

[17] World Wildlife Fund (WWF) and Vancouver Foundation, "B.C. perspectives on fresh water," McAllister Opinion Research, 2010, http://assets.wwf.ca/downloads/bc_water_polling_summary___nov_2010_2.pdf

[18] For more information see: Government of British Columbia, "Policy proposal on British Columbia's new Water Sustainability Act Released — Have your say," January, 2011, http://www.livingwatersmart.ca/

2. Shale gas extraction: how it impacts water

2.1 Depleting water resources

To extract shale gas, companies first must drill down approximately 2,000 metres before extending wells horizontally into the target formations. They then pump fluids down the well until the pressure within the formation builds to the point at which 500 to 800 foot-long fractures are created.[19] During the "completion" phase of the well hydraulic fracturing is an ongoing process where different segments of the horizontal portion of the well are fractured separately.[20]

Hydraulic fluids consist primarily of water (approximately 98%) as well as chemical additives and sand, which are added in order to prop open fractures. There are several sources for that water including surface water, shallow ground water (typically fresh water connected with surface water systems), and deep groundwater (often saline and disconnected from surface water systems). Companies can also use different sources of wastewater. This includes flowback water, which is a combination of the injected water and water from the gas formations that is returned to the surface and then recovered during gas extraction. Industry can also recycle wastewater from other uses, such as municipal water use. Surface water, however, is the most commonly used source in northeastern British Columbia for hydraulic fracturing.[21]

In cases where natural gas extraction depletes fresh surface or ground water systems there is potential for conflict with other human uses (e.g., agriculture and domestic use) and to cause negative ecological impacts (e.g., reduced in-stream flows degrading bull trout habitat). The extent of these conflicts and environmental impacts depends on the water demands present and the availability of water to meet those demands.

There are an increasing number of examples where companies are using alternatives to surface or underground sources of fresh water. Recycling a portion of flowback water is the most common alternative approach, with the Oil and Gas Commission estimating that 20% of the water requirements for hydraulic fracturing in northeast B.C. are met with re-used flowback water.[22]

An example of a B.C.-based project that recycles wastewater is Shell's agreement to help finance a wastewater treatment facility for the community of Dawson Creek. Under the agreement, Shell has access to 3.4 million litres of treated water per day, which is subtracted from the treatment

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[19] M. Zoback, S. Kitasei & B.Copithorne, *Addressing the Environmental Risks from Shale Gas Development,* Worldwatch Institute, July 2010, http://www.worldwatch.org/system/files/NGBP1-ShaleGasDev_0.pdf

[20] K.Campbell, "Shale Gas Development and Water Issues In Northeastern British Columbia," Schlumberger Presentation at the Canadian Institute Sixth Annual Shale Gas Conference, Calgary, Alberta, slide 8*,* January 2010.

[21] A. Chapman, "Development of a Hydrology Decision Support Tool," Presentation to the 2011 Unconventional Gas Forum, slide 4

[22] Allan. Chapman, Hydrologist, B.C. Oil and Gas Commission, personal communications, June 2011.

plant's total output of 4.5 million litres per day.[23] An example of a B.C.-based project that uses saline ground water is a joint Apache and Encana project in the Horn River that draws from the Debolt reservoir.[24] The potential applicability and affordability of these types of alternatives, on a broad scale, is not well understood and currently they are not used with normal industry practice.

The amount of water needed per well varies depending on the type of shale gas formation. In the United States, companies have used between 7.6 and 26.5 million litres (7,600 – 26,500 m^3) of water per well on average to extract gas from Marcellus Shale, with multiple wells drilled from each pad.[25] This is comparable to Shell's experience in its Groundbirch operation in the Montney Basin where wells have required five to 10 million litres of water per well.[26] Some industry estimates for shale gas wells in northeast B.C. are significantly higher, with up to 90 million litres of water needed per well.[27]

A recent B.C. shale gas well came close to this upper estimate. In the spring of 2010, Apache Corporation conducted what was, at the time, the largest North American hydraulic fracturing job ever conducted, consisting of 274 separate fractures on a 16 well pad in the Horn River Basin.[28] A total of 980 million litres of water (a mix of fresh water and fracture flowback water) was used to complete the operation, amounting to an average of 61 million litres per well.[29]

Over time continued drilling activity could significantly impact water resources in B.C. depending on the number of wells drilled, the amount of water needed and the sources of water relied upon. For example, Apache Corporation plans to drill 2,000 to 3,000 wells in the Horn River Basin over the next several decades.[30] Table 1 illustrates the range of total and annual water demands that could stem from 2,500 wells being drilled in the Horn River over the next 20 years. These amounts represent potential water usage for just one operator in the Horn River

[23] City of Dawson Creek, "Agreement reached on reclaimed water plant," media release, August 18, 2010. http://www.planningforpeople.ca/documents/PRESSRELEASE-ReclaimedWaterPlantElectorApprovalProcessAug18.pdf

[24] For more information see: Canadian Association of Petroleum Producers (CAPP), Stewardship in Practice — The Debolt Water Treatment Project," 2011, http://www.capp.ca/energySupply/innovationStories/Water/Pages/debolt.aspx

[25] J. W. Ubinger, J.J. Walliser, C. Hall & R. Oltmanns, "Developing the Marcellus Shale: Environmental policy and planning recommendations for the development of the Marcellus Shale play in Pennsylvania, Pennsylvania Environmental Council, July 2010

[26] Christa Seaman, Emerging Regulatory Policy Issue Advisor, Shell Canada, personal communications, May 4, 2011

[27] K. Campbell, "Shale gas development and water issues in northeastern British Columbia," Schlumberger presentation at the Canadian Institute Sixth Annual Shale Gas Conference, Calgary, Alberta, slide 9. January, 2010

[28] Apache Corporation, "The Horn River Project — Ootla team celebrates largest completions in North America" media release, July 2010, http://www.apachecorp.com/explore/Browse_Archives/View_Article.aspx?Article.ItemID=1130

[29] Ibid.

[30] Oil & Gas Inquirer, "Big Stuff — British Columbia's shale and tight gas plays are already world-class, and there may be more to come," December 2009, http://www.oilandgasinquirer.com/printer.asp?article=profiler%2F091201%2FPRO2009%5FD10000%2Ehtml No estimates of the number or density of well pads were available.

Basin. They do not account for the other operators in the Horn River Basin or the operators in the Montney Basin.

Table 1 – Potential water use associated with Apache Corporation's planned 2,500 wells in Horn River

	Water used (billion litres)			
	Assuming 7.6 million litres / well1	Assuming 25.5 million litres / well2	Assuming 61 million litres / well3	Assuming 90 million litres / well4
Total water used	19	64	152	225
Annual water used (assuming 20 years of activity – 125 wells/year)	1	3	8	11

1 – Low-end experience from Marcellus shale
2 – High-end experience from Marcellus shale
3 – Apache Corporation experience in Horn River basin
4 – High-end estimate for northeast B.C.

The actual amount of fresh water used by the oil and gas industry is uncertain. B.C. oil and gas companies were licensed or authorized to use 86.5 billion litres of surface water in 2009.[31] However, a preliminary look at actual water use in the Horn River Basin in 2009 resulted in an estimate that was about five per cent of the approved volume.[32] Part of the reason for the discrepancy is that approvals were historically granted assuming that water use would occur throughout the year when in fact needs are typically met in relatively short periods of time. The Oil and Gas Commission has recently shifted to an approval system that is based more on actual need; 2011 approvals are about 25% of the previous rates.[33] In addition to surface water approvals, 6.7 billion litres have been withdrawn from water source wells over their lifetime for an average of 0.5 billion litres per year.[34]

An important piece of the puzzle that is beyond the scope of this report is producing projections of water demand through the year on a region-by-region basis for different growth scenarios in the Horn River and Montney. That projection would ideally include water demands for all major water users and not just oil and gas. Having that information would make it feasible to project how much cumulative demand would be placed on different watersheds at different times of the year. Those types of numbers could then be combined with flow estimates for different watersheds to help articulate the scale of the challenges and conflicts to be anticipated.

Demand for water resources in Dawson Creek provides a good illustration of the types of potentially competing demands that can be placed on a watershed. Bulk water sales from the City to the oil and gas industry have doubled every year since 2004, and in 2008, 340 million litres — or 16% — of Dawson Creek's allocated drinking water supply from the Kiskatinaw River was sold to the oil and gas industry for use in its operations.[35] These bulk water sales are in addition

[31] B.C. Oil and Gas Commission, "Oil and gas water use in British Columbia," p. 22, 2010
[32] Ibid. p. 4
[33] Allan Chapman, Hydrologist, B.C. Oil and Gas Commission, personal communications, June 2011
[34] B.C. Oil and Gas Commission, "Oil and Gas Water Use in British Columbia," p. 24, 2010
[35] Cheryl Shuman, Councilor, City of Dawson Creek, personal communications, 2010

to the short-term uses allocated to the oil and gas industry from streams, rivers and lakes in the region.

A Forest Practices Board cumulative effects assessment of the Kiskatinaw River Watershed identifies the great deal of uncertainty regarding water sources, when they are abstracted as well as how much water is allocated to different users. In discussing the potential implications of the lack of information regarding water use in the oil and gas sector, the Forest Practices Board report concludes that:

> "...We in no way imply that the citizens of Dawson Creek should be unconcerned about issues of water quantity or quality. In particular, there have been episodes in the past of very low flow (zero, in fact). Depending on when these occur in the future, the consequences for Dawson Creek could be severe."[36]

2.1.1 Other stressors: droughts and hydrology changes

A further challenge in assessing our ability to meet future water demands is that water supplies can, and likely will, change over time. For instance, parts of northeast B.C. experienced 'persistent and severe summer drought' conditions in 2010, which prompted the Oil and Gas Commission to suspend surface water withdrawals in four river basins in the Peace Region for several months.[37]

A second example of this type of stressor to water systems is changes in hydrology due to climate change. A recent analysis by the Pacific Climate Impacts Consortium assessed the impacts of climate change on the Peace River, Columbia River and Campbell River. For the Peace, the study projects increased water flow in October through May followed by a drop in flow in June through September.[38]

2.2 Water contamination risks

The composition of fracture fluids can vary widely. In shale gas extraction typical fluids are composed of water, sand and chemicals. Contributing up to two per cent by volume, these additives vary depending on the target rock formation. Typical additives include *friction reducers* to reduce the resistance to the movement of the fluid through the well casing, *biocides* to prevent bacterial colonization and growth that can lead to formation of hydrogen sulphide,

[36] Forest Practices Board, "A case study of the Kiskatinaw River watershed — an Appendix to Cumulative Effects: From assessment towards management," p. 3, March 2011, http://www.fpb.gov.bc.ca/SR39_CEA_Case_Study_for_the_Kiskatinaw_River_Watershed.pds

[37] B.C. Oil and Gas Commission, "Water Use Suspension Directive 2010-05: Suspension of surface water withdrawals (Peace River)," Aug 11, 2010, page 1, http://www.bcogc.ca/documents/directives/dir_2010-05_Suspension_of_Surface_Water_Withdrawals.pdf

[38] Pacific Climate Impacts Consortium, "Hydrologic impacts of climate change on BC water resources," 2011, http://pacificclimate.org/sites/default/files/publications/Zwiers.HydroImpactsSummary-CampbellPeaceColumbia.Jul2011-SCREEN.pdf

scale inhibitors to prevent material build up on casings as well as sand or ceramic beads to hold fractures open.[39]

Democratic members of three U.S. House of Representatives committees recently published a list of 750 substances used in hydraulic fracturing of oil and gas wells in the U.S. between 2005 and 2009 based on information voluntarily provided by producers. Of these substances, 29 are known to be possible human carcinogens and/or regulated toxic chemicals.[40] Non-toxic fracture fluids are available for some applications although they cost more than typical fluids.[41]

In addition to the fracturing fluids, flowback can have high concentrations of salts, naturally occurring radioactive material (NORM) and other contaminants including arsenic, benzene and mercury that are contained in shale gas and adjoining geologic formations.[42] The amount of saline formation water produced from gas shales varies widely, from none to tens-of-thousands of litres per day per well.[43]

The net effect is that the flowback water from hydraulic fracturing is contaminated by fracturing fluid chemicals and by the salts and other substances found in the target formation. For example, wastewater from Marcellus Shale operations can be up to one-third total dissolved solids by volume, or as much as 10 times more saline than seawater.[44]

As discussed in Section 2.1, some of the flowback water is reused in subsequent hydraulic fracturing activities. However, where this does not occur it is important that the water be handled as safely as possible, and re-injected back into deep well aquifers. This practice is required by the B.C. Oil and Gas Commission, and it is important because the wastewater kills vegetation and severely degrades soil quality if it is discharged on land. It is also harmful to aquatic life and fish and can seriously degrade the quality of groundwater.

2.2.1 Sub-surface contamination risks

The primary concern related to sub-surface contamination, which is not limited to shale gas extraction, is potential failures in the steel and cement casings that surround gas wells. These

[39] National Energy Technology Laboratory, "State Oil and Natural Gas Regulations Designed to Protect Water Resources," U.S. Department of Energy, Office of Fossil Energy, May 2009, http://www.gwpc.org/e-library/documents/general/State%20Oil%20and%20Gas%20Regulations%20Designed%20to%20Protect%20Water%20Resources.pdf

[40] United States House of Representatives Committee on Energy and Commerce, Minority Staff, "Chemicals Used in Hydraulic Fracturing," p. 1 & 8, 2011, http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf

[41] K. Kohl, "Making Hydraulic Fracturing Cleaner: Industry insider explains 'green' fracking technologies," Energy and Capital, April 5, 2010, http://www.energyandcapital.com/articles/what-you-didnt-know-about-hy/1113

[42] M. Zoback, S. Kiasei, B. Copithorne, Worldwatch Institute, Addressing the Environmental Risks from Shale Gas Devlopment. July 2010.

[43] National Energy Board, "A primer for understanding Canadian shale gas," p. 11, http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.pdf

[44] J. W. Ubinger, J.J. Walliser, C. Hall & R. Oltmanns, "Developing the Marcellus Shale: Environmental policy and planning recommendations for the development of the Marcellus Shale play in Pennsylvania," p. 29, Pennsylvania Environmental Council. July 2010

casings are designed specifically for hydraulic fracturing operations to prevent any contact between the contents of the well and the surrounding rock and water underground. If they are improperly sealed, natural gas, fracturing fluids and formation water can leak outside of the well into the target formation, drinking water aquifers and the layers of rock in between.[45]

In some cases, shallow biogenic methane can be incorrectly linked with natural gas extraction. That said, the migration of deep sources of natural gas to the surface (including into water wells and other surface structures) as a result of inadequate cementing/casing of oil or gas wells (e.g., in some cases old, abandoned wells), has been clearly established in multiple settings, including oil wells in Alberta and coalbed methane wells in the U.S.[46]

In 2009 the Pennsylvania Department of Environmental Protection established that faulty cementing/casing of modern shale gas wells was the cause of gas migration into the water supplies of 14 homes. The company at fault — Cabot Oil and Gas Corporation — failed to initially remedy the problem and was eventually required to cap the wells, install water systems in the impacted homes, suspend drilling for one year in the area impacted by gas migration and pay $240,000 into the state's well plugging account.[47]

In 2007, a well that had been drilled almost 4,000 feet into a tight sand formation in Bainbridge, Ohio was not properly sealed with cement, allowing gas from a shale layer above the target tight sand formation to travel into an underground source of drinking water. The methane eventually built up until an explosion in a resident's basement alerted state officials to the problem.[48, 49] Similarly, in November 2010, Quebec government inspectors detected very high methane concentrations — in excess of 20% — in the air surrounding four different shale gas exploration wells.[50] The provincial environment ministry has confirmed, in at least one of these cases, that the methane is from the shale gas and not from biological sources.[51]

A recent study from Osborn *et al.* (2011) compiled evidence for methane contamination of drinking water associated with shale gas extraction and affirmed well-casing failures as the most likely cause of groundwater contamination.[52] The same study also raised an additional potential

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[45] M. Zoback, S. Kiasei & B. Copithorne, "Addressing the environmental risks from shale gas development," p. 8, Worldwatch Institute, July 2010

[46] Ibid, p. 67–69

[47] J. Hanger, *Testimony before the Senate Environmental Resources and Energy Committee,* Department of Environmental Protection, June 16, 2010, http://files.dep.state.pa.us/AboutDEP/AboutDEPPortalFiles/RemarksAndTestimonies/TestimonyEOGSafety_061610.pdf

[48] M. Zoback, S. Kiasei & B. Copithorne, "Addressing the environmental risks from shale gas development," Worldwatch Institute, July 2010

[49] Ohio Department of Natural Resources, Division of Mineral Resources Management, "Report on the investigation of the natural gas invasion of aquifers in Bainbridge Township of Geauga County, Ohio," September 1, 2008

[50] Bureau d'audiences publiques sur l'environnement, "Développement durable de l'industrie des gaz de schiste au Québec," document DQ35.1, 2011, http://www.bape.gouv.qc.ca/sections/mandats/Gaz_de_schiste/documents/liste_doc-DT-DQ-DM.htm#DQ

[51] L.G. Francoeur, "Gaz de schiste: six dossiers d'infraction," *Le Devoir*, January 28, 2011, http://www.ledevoir.com/environnement/actualites-sur-l-environnement/315622/gaz-de-schiste-six-avisd-infraction

[52] S. Osborn *et. al.,* "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing," The National Academy of Sciences of the United States of America, p. 8172-6, 108(20), 2011

pathway for contamination in that methane could be migrating through a network of existing and newly created fractures towards the surface. It characterized this pathway as less likely than well-casing failure but flagged it as a concern that merits further investigation.

Concerns have also been raised about the potential for contaminated water to migrate directly between layers of shale gas and ground water aquifers. The likelihood of such an occurrence in most shale gas formations is considered very low because of their significant depth relative to groundwater aquifers. For example, the Montney and Horn River basins are at depths of 1,700 to 4,000 metres and 2,500 to 3,000 metres respectively.[53] This compares to the normal depth of domestic potable water wells in northeastern B.C., which is between 18 and 150 metres.[54]

The Ground Water Protection Council, which is an association of U.S. state groundwater regulatory agencies including departments of both environment and natural resources, has concluded that the depth and the intervening rock barriers make any contamination of groundwater extremely unlikely.[55] It was also confirmed by Osborn *et al.* (2011), which found no evidence of contaminants apart from methane.[56] However, at least one hydro-geologist has produced a detailed analysis concluding that deep fracture fluids could reach fresh water in decades to centuries.[57]

The risk of contaminated water migrating directly between layers of shale gas and ground water aquifers has not been explored in detail for shallow shale gas deposits. Two shale gas deposits that display these characteristics are the Colorado shale (southern Alberta and Saskatchewan) and Utica shale (southern Quebec), which are at depths as shallow as 300 metres and 500 metres respectively.[58] In cases where shale gas deposits are at shallower depths, the B.C. Oil and Gas Activities Act allows hydraulic fracturing in any wells as shallow as 600 meters and opens the potential for shallower operations.[59]

2.2.2 Surface contamination risks

Estimates as to how much flowback water exists vary widely depending on the shale formation. For example:

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[53] National Energy Board, "A primer for understanding Canadian shale gas," Table 1, 2009, http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.pdf

[54] B.C. Oil and Gas Commission, "Oil and gas water use in British Columbia," p. 14, 2010

[55] Ground Water Protection Council & ALL Consulting, "*Modern Shale Gas Development in the United States: A primer,"* U.S. Department of Energy, p. 53-4, 2009, http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf

[56] S. Osborn *et. al*., "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing," The National Academy of Sciences of the United States of America, p. 8172-6, 108(20), 2011

[57] T. Myers, "Review and analysis of draft supplemental generic environmental impact statement on the oil, gas and solution mining regulatory program well permit issuance for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus Shale and other low-permeability gas reservoirs," Natural Resources Defense Council, p. 9–14 & Appendix A, 2009, http://docs.nrdc.org/energy/files/ene_10092901d.pdf

[58] National Energy Board, "A primer for understanding Canadian shale gas," Table 1, 2009.

[59] Government of British Columbian, B.C. Oil and Gas Activities Act, Section 21. http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/536427494#section21

- British Columbia Oil and Gas Commission states that roughly 50 to 90% of fracturing fluids are recovered.[60]
- United States Environment Protection Agency states that 15 to 80% of fracturing fluids are recovered.[61]
- The Post-Carbon Institute states that between 30 and 70% of the injected water is brought back to the surface in addition to any formation water present.[62]
- World Watch Institute states that roughly 25% of the fracturing fluids from Marcellus shale are recovered.[63]

The flowback water not reused in future hydraulic fracturing activities needs to be disposed of. The necessity to routinely store and transport and ultimately dispose of large volumes of flowback water does introduce a risk of surface contamination. Temporary storage tanks, storage pits, transport trucks and pipelines can all leak or spill. Spills of large volumes of wastewater are a familiar concern in the conventional upstream oil and gas industry and these spills of produced water generally far exceed spills of oil by volume. In Alberta, oil and gas companies spilled 23.3 million litres of produced water compared to 6.8 million litres of oil in 2009.[64]

The B.C. Oil and Gas Commission keeps statistics on disposed water for the entire industry and the volumes of disposed water have recently risen considerably. As shown in Figure 2, approximately 1.2 billion litres of produced water was disposed of in 1990, which rose to 4.2 billion litres in 2009 (an average increase of seven per cent per year).[65] These volumes include flowback water that is not reused.

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[60] B.C. Oil and Gas Commission, "Fracturing (fracing) and disposal of fluids fact sheet," 2010, http://www.bcogc.ca/documents/publications/Fact%20Sheets/Fracturing_and_Disposal_of_Fluids_FINAL.pdf

[61] United States Environmental Protection Agency, "Hydraulic Fracturing Research Study," 2010, http://www.epa.gov/safewater/uic/pdfs/hfresearchstudyfs.pdf

[62] D. Hughes, "Will natural gas fuel America in the 21st century?" post-carbon institute, p. 24, 2011

[63] M. Zoback, S. Kiasei & B. Copithorne, "Addressing the environmental risks from shale gas development," p. 10, July 2010

[64] Energy Resources Conservation Board, "Field Surveillance and Operations Branch Provincial Summary 2009: ST57-2010", August 2010, page 21, http://www.ercb.ca/docs/products/STs/ST57-2010.pdf

[65] The 4.2 billion litres disposed is a small fraction (five per cent) of the 86 billion litres allocated for use. This discrepancy is likely mostly explained by the fact that the Oil and Gas Commission estimate that less than five per cent of allocated water is actually used. Other possible explanations include volumes of flowback water being low relative to water consumed, volumes of flowback water being underreported as well as an amount of flowback water being recycled.

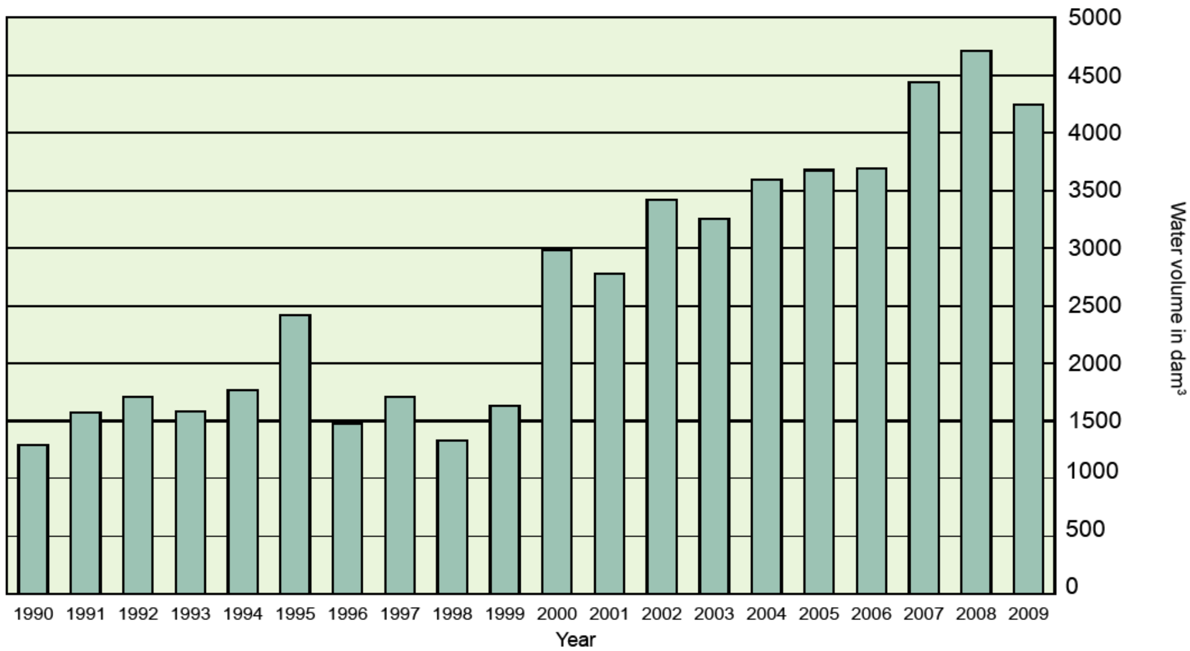

Figure 2 — Annual subsurface water disposal and injection in B.C.[66]

Deep well disposal of flowback water is the next best approach for disposal if it cannot be reused. The success of this disposal method depends on stringency of the rules that govern the siting and design of the disposal wells, the monitoring regime that is used and the government enforcement system. Where pits are used to store flowback water the best approach is to build a double lined pit with leachate collection and leachate monitoring. This method is an Oil and Gas Commission requirement.[67]

2.2.3 Blow-out risks

Uncontrolled fluid and gas releases can occur when the pressures encountered during drilling and fracturing exceed the ability of the cement or drilling mud used to contain fluids and gases (blow-outs). The recent BP Deepwater Horizon disaster in the Gulf of Mexico is a particularly notorious example of this type of accident.[68] There have also been recent gas well blowouts in Pennsylvania and West Virginia during drilling operations in the Marcellus Shale.[69]

The potential for nearby fracturing activity to cause pressures to change unpredictably elevates the risks of such blowouts in shale gas extraction. For instance, the B.C. Oil and Gas Commission issued a safety directive in May 2010 after it found 18 instances where hydraulic fracturing led to connections being formed between the fractures of adjacent wells or drilling

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[66] B.C. Oil and Gas Commission, "Oil and gas water use in British Columbia," p. 24, 2010

[67] B.C. Oil and Gas Commission, *Information letter 09-07,* 2009, http://www.bcogc.ca/documents/informationletters/OGC%2009-07%20Storage%20of%20Fraccing%20Fluid%20Returns.pdf

[68] National Commission on the BP Deepwater Horizon Spill and Offshore Drilling, "*Deep Water: The Gulf oil disaster and the future of offshore drilling*," p. 115,, 2011, http://www.oilspillcommission.gov/final-report

[69] M. Zoback, S. Kiasei & B. Copithorne, "Addressing the environmental risks from shale gas development," Worldwatch Institute, July 2010.

intersected a fracture from another well. The incidents resulted in potentially hazardous changes in pressure during drilling that can result in suspended production and substantial remediation costs as well as pose a potential safety hazard.[70] The Oil and Gas Commission states:

> "Fracture propagation via large scale hydraulic fracturing operations has proven difficult to predict. Existing planes of weakness in target formations may result in fracture lengths that exceed initial design expectations."[71]

All of the recorded incidents were successfully controlled, but they still resulted in up to 80,000 litres of produced fluids coming to the surface.[72]

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[70] B.C. Oil and Gas Commission, "Safety Advisory 2010 – 03: Communication during fracture stimulation," 2010, page 1, http://www.bcogc.ca/documents/safetyadvisory/SA%202010-03%20Communication%20During%20Fracture%20Stimulation.pdf

[71] Ibid

[72] Ibid

3. Regulating water use by British Columbia's gas industry

In order to fully understand the scope of the potential water impacts associated with shale gas development in British Columbia, it is important to have an understanding of how government regulations operate with respect to water use by industry. As will be shown below, there are concerns about the adequacy, independence and comprehensiveness of oversight at this time.

3.1 Overview of the Oil and Gas Commission

Oversight of oil and gas activities is shared among a number of provincial government bodies, primarily the Ministry of Energy and Mines[73], the Ministry of Forests, Lands and Natural Resource Operations[74], and the Ministry of Environment. Government changes announced in October 2010 and March 2011 have resulted in a realignment of roles and responsibilities for resource development in British Columbia, the implications of which are not yet fully understood.

The Ministry of Energy and Mines remains the primary ministry with policy responsibility for oil and gas development while responsibility for oversight and implementation of the oil and gas regime in B.C. lies with the Oil and Gas Commission.[75] It was initially designed to be independent of the provincial government but a legal change in 2002 minimized this independence, giving the Deputy Minister of the Ministry of Energy the role of Chair of the three-person Board of the Commission.[76] This effectively means that the B.C. government can strongly influence the operational activities of its supposedly independent regulator.

3.2 Allocating water

The Water Act requires that water users obtain water licences or short-term water use approvals for most water usage in the province. Table 2 describes the different ways that water can be accessed by the oil and gas industry.

[73] Formerly the Ministry of Energy.

[74] Formerly the Ministry of Forests, Mines and Lands, and the Ministry of Natural Resource Operations.

[75] Authorized under the Oil and Gas Commission Act [SBC 1998] Chapter 39

[76] Government of British Columbia, Oil and Gas Activities Act, section 2, http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_08036_01#section2

Table 2 – Pathways for water allocation to the oil and gas sector in B.C.

Type of water source	Act regulating water allocation	Tracked by OGC	Specific allocation pathways[4]
Natural surface water (e.g., streams, rivers and wetlands)	Water Act	Yes	Two options: • Ministry of Forests, Lands and Natural Resource Operations long-term surface water licences. • Oil and Gas Commission short-term surface water use permits.
Collected surface water (i.e., dugouts)[1]	Water Act	Yes	• Oil and Gas Commission short-term surface water use permits.
Water source wells for oil and gas activity (both shallow and deep, saline and fresh)	Oil and Gas Activities Act	Yes	• Oil and Gas Commission authorized subsurface water source wells.
Agreements with non-oil and gas users who have surface licences or short-term surface water use permits.[2]	Water Act	No	Two options • Ministry of Forests, Lands and Natural Resource Operations long-term surface water licences. • Ministry of Forests, Lands and Natural Resource Operations short-term surface water use permits
Agreements with non-oil and gas users who have groundwater access.	Allocation is not regulated[3]	No	• Not applicable
As a by-product of oil and gas production (e.g. flowback water from hydraulic fracturing).	Allocation is not regulated	No	• Not applicable

[1] Dugouts are large pits used to collect water for use in oil and gas activity that were recently required to have short-term water permits.[77] An example of these types of pits is an Oil and Gas Commission approved plan by Nexen to dig a "borrow pit" measuring 560 metres long, 200 metres wide and 13 metres deep near the Horn River Basin, which would be used as a water reservoir with water either pumped into the pit or allowed to infill naturally.[78] A pit of those dimensions would hold 1.5 billion litres of water.
[2] An example in this category is the 340 million litres — or 16% — of Dawson Creek's allocated drinking water supply from the Kiskatinaw River that was sold to the oil and gas industry for its operations in 2008. Bulk water sales by Dawson Creek to the oil and gas industry have doubled every year since 2004.[79]
[3] If the groundwater extraction of water exceeds 75 litres per second, the allocation can be subject to B.C. environmental assessment.
[4] Allocations administered by the Ministry of Forests, Lands and Natural Resource Operations were administered by the Ministry of Environment prior to a restructuring in 2010.

There are several regulatory concerns relating to Table 2:

- Gaps in groundwater regulation (Section 3.2.1).
- Problems with short-term surface water permits (Section 3.2.2).
- Incomplete picture of oil and gas water use (Section 3.2.3).
- Gaps in overall oversight of water use in northeast B.C. (Section 3.2.4).

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[77] B.C. Oil and Gas Commission, *Directive 2011-02*, 2011, http://www.bcogc.ca/document.aspx?documentID=1063&type=.pdf

[78] This plan was approved under Section 14 of the Land Act, not under the Water Act: B. Parfitt, "Worried About Gas Exploration? Look to B.C.," January 2011, http://www.nbmediacoop.org/index.php?option=com_content&view=article&id=1341:ben-parfitt&catid=82:environment&Itemid=197

[79] Cheryl Shuman, Councilor, City of Dawson Creek, personal communications, 2010

While this report places an emphasis on water allocation and use, it should be mentioned here that the Environmental Protection and Management Regulation under the Oil and Gas Activities Act also provides enabling authority for protection of identified aquifers, identified groundwater recharge areas and source areas for community wells (i.e., capture zones) from specific oil and gas activities. However, for these protection areas to have legal status they have to be delineated and, for aquifers and recharge areas, ordered under S34 of the Regulation.

3.2.1 Gaps in well regulation

While oil and gas companies are required to obtain permits for water source wells under the Oil and Gas Activities, other users are not currently required to do so. In addition to being a general gap in the regulatory framework for water use in B.C., it introduces a specific problem within the natural gas sector because companies can make arrangements with non-regulated users and effectively secure access to water without any government oversight. This gap has also been identified in the Water Act Modernization process. The draft policy proposal stemming from that process could address the gap depending on how it is implemented. According to the proposal:[80]

> *"Groundwater extraction and use will be regulated in problem areas and for all large groundwater withdrawals across BC. All existing and new large groundwater users throughout the province will be required to obtain a licence or an approval. The definition of a large withdrawal is currently being determined, and could potentially be in the range of 250 to 500 cubic metres per day for wells in unconsolidated aquifers and 100 cubic metres per day for wells in bedrock aquifers."*

The final definitions of 'problem areas' and 'large users' will determine the extent to which the gap is addressed.

3.2.2 Problems with short-term surface permits

Section 8 of the Water Act allows for short-term water use permits for temporary, one-year uses. For oil and gas activity, the Oil and Gas Commission administer these section 8 permits. The oil and gas industry has generally opted to secure access to water through these Section 8 permits rather than water licenses. As of fall 2010, oil and gas companies had 13 active water licences[81] whereas there were 297 Section 8 approvals for 897 points of withdrawal in fiscal 2009.[82] There are two problems with this approach to authorizing water use:

1. The short-term nature of Section 8 approvals fits the needs of specific wells, but it does not fit the longer-term demands of the natural gas sector where projected activity over the coming decades is going to require ongoing access to water. Water licences (such as those granted to run-of-river hydro projects, for example) require a longer-term review of the availability of water, and a similar type of review would be appropriate in the

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[80] Government of British Columbia, *Policy proposal on British Columbia's new Water Sustainability Act*, page 9, December 2010, http://www.livingwatersmart.ca/water-act/docs/wam_wsa-policy-proposal.pdf

[81] Personal communications, Ben Parfitt, Canadian Centre for Policy Alternatives, August 2011. Based on analysis of British Columbia's water licenses database available at http://a100.gov.bc.ca/pub/wtrwhse/water_licences.input.

[82] B.C. Oil and Gas Commission, "Oil and gas water use in British Columbia," p. 20, 2010. The actual report states 807 approvals but the report was in error (Personal communications, Allan Chapman, Hydrologist, B.C. Oil and Gas Commission, June 2011).

approval process for oil and gas activity. That said, the assessment might be more appropriate at a strategic level as opposed to a well-by-well basis.

2. There is also a more general concern that regulatory bodies that have a role promoting oil and gas development (or that are directed by those that have such a role) face a conflict of interest if they are also responsible for environmental safeguards that may make development more difficult.

3.2.3 Incomplete picture of oil and gas water use

The Oil and Gas Commission does not have a complete picture of water use from the industry and, as a result, is not able to completely understand the industry's demand for water resources and the resultant impact on water systems in the Northeast. The most important of these gaps are the agreements reached with other water users for regulated surface water allocations and non-regulated ground water access. We are not aware of any publicly available information that would allow the scale of these gaps to be estimated.

3.2.4 Gaps in the oversight of water use in northeastern British Columbia

The situation in which some water uses are not regulated at all (non-oil and gas water wells), the oil and gas sector is (mostly) regulated by the Oil and Gas Commission and other users are regulated by the Ministry of Forests, Lands and Natural Resource Operations means that no agency is responsible for a complete picture of water allocation, use and impact on water systems in the province's northeast. Figure 3 illustrates this split responsibility by showing the respective usage of water licenses and Oil and Gas Commission short-term water use permits across B.C. in 2010. As shown, northeast B.C. (and the south Peace in particular) sees a significant overlap of water allocation from water licenses (from Ministry of Environment) and Section 8 approvals (from the Oil and Gas Commission). These maps do not include other Section 8 approvals that are issued by the Ministry of Forests, Lands, and Natural Resource Operations to non-oil and gas users.

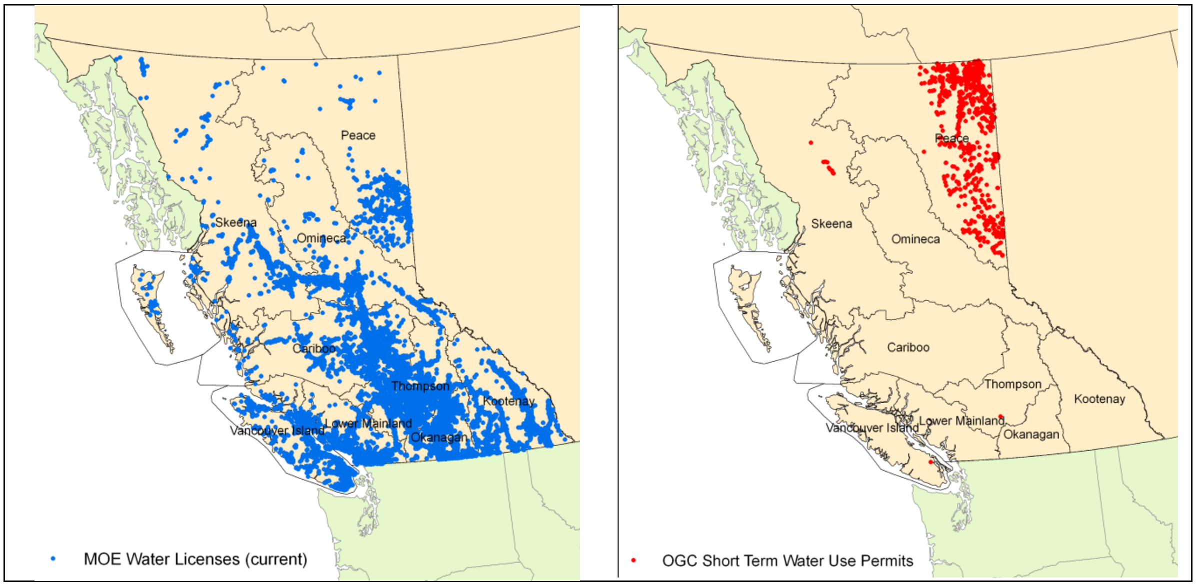

Figure 3 — The map on the left shows the distribution of water licenses across the province, whereas the map on the right illustrates that short term water use permits are granted extensively in northeast B.C.

3.3 Reporting water withdrawals

Oil and gas companies are required to record the amount of water actually withdrawn under their Section 8 permits and the Oil and Gas Commission has recently required monthly withdrawal volumes to be reported to the Commission on a quarterly basis.[83] The first compilation of those reports was recently made publicly available.[84]

Whether or not license holders have to monitor or report actual water withdrawals depends on the specific licensing conditions.[85] The most recent proposals under the Water Act Modernization process would have large licenses required to monitor actual water use, and in some cases (e.g., in problem areas) stream flow, groundwater levels, well performance, and water quality.[86] This would be an improvement in helping to understand total water use in northeast B.C. but it could leave a gap if oil and gas companies are making arrangements with small licence holders to access water. In making that information publicly available, it should also be a priority to make the format through which it is accessed as user-friendly as possible, because the current water license database is very challenging to navigate.

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[83] B.C. Oil and Gas Commission, *Directive 2011-02*, March 2011, http://www.bcogc.ca/document.aspx?documentID=1063&type=.pdf

[84] B.C. Oil and Gas Commission, *Quarterly Report on Short-Term Water Approvals and Use*, August 2011, http://www.bcogc.ca/document.aspx?documentID=1128&type=.pdf

[85] Based on analysis of water licenses granted to oil and gas operations in the fall of 2010, five out of 13 licences have as conditions a requirement that the holders maintain data on actual water withdrawals (personal communications, Ben Parfitt, August 2011).

[86] Government of British Columbia, *Policy proposal on British Columbia's new Water Sustainability Act*, page 12, December 2010, http://www.livingwatersmart.ca/water-act/docs/wam_wsa-policy-proposal.pdf

The issue of water monitoring suffers from the same gaps discussed in Section 3.2.4 in that no agency is responsible for a complete picture of water use and non-oil and gas water wells are not regulated at all (although this could change through the Water Act Modernization process).

3.4 Baseline data

The provincial network of groundwater observation wells includes 146 wells and there are two in northeast B.C. near Charlie Lake and Tumbler Ridge.[87] And while oil and gas activity has been occurring in northeast B.C. for years, no records have been compiled of any of the previous impacts of existing water use in the region — for ground or surface water.[88] Implicit in this concern is that there is limited understanding of the respective demands for water by the environment, by people and by competing uses such as agriculture.

Geoscience BC, an industry-led organization seeking to encourage mineral and oil & gas exploration investment in British Columbia, is currently undertaking a study that will develop a database of surface water, ground water and saline aquifers in the Montney region.[89] However this work began in October 2010, well after many of the tenures were granted and initial drilling activity had already commenced. Ideally, this type of baseline analysis would be undertaken before development was underway.

Geoscience BC has also conducted some research into the aquifers in the Horn River Basin to assess their ability to supply water for hydraulic fracturing and accept produced water from fracturing activities. The results of the study indicate that within the broader Horn River Basin there are large volumes of saline water that could be used for fracturing and the potential to dispose of large volumes of wastewater. The degree to which that availability matches well with specific areas of operation will vary and is still uncertain.[90] And in early 2011, Geoscience BC issued a request for proposals to study the quality and quantity of surface water in the Horn River, and its availability for shale gas development.[91]

A 2010 report by the B.C. Auditor General has confirmed that there are concerns about the level of knowledge about groundwater resources in the province. The B.C. Auditor General concluded that:

- The Ministry of Environment's information about groundwater is insufficient to enable it to ensure the sustainability of the resource;

[87] Data for the two Peace Region wells is available here: http://www.env.gov.bc.ca/wsd/data_searches/obswell/waterlevels/obs_wells_Region_7B.html.

[88] The need to improve the manner in which groundwater issues are addressed is one of the identified priority areas in the Water Act Modernization process. See British Columbia's Water Act Modernization, Policy Proposal on British Columbia's new Water Sustainability Act, December 2010.

[89] Geoscience B.C., "Geoscience B.C. announces Montney Water Project," media release, October 14, 2010, http://www.geosciencebc.com/s/NewsReleases.asp?ReportID=423045&_Type=News&_Title=Geoscience-BC-Announces-Montney-Water-Project

[90] Petrel Robertson, "Horn River Basin aquifer characterization project," January 2010, http://www.geosciencebc.com/i/project_data/GBC_Report2010-11/HRB_Aquifer_Project_Report.pdf

[91] See http://www.geosciencebc.com/i/pdf/RFP/GBC_HRBPG_Water_Monitoring_Study_RFP_FINAL.pdf

- That groundwater is not being protected for depletion and contamination or to ensure the viability of the ecosystems it supports; and
- That control over access to groundwater is insufficient to sustain the resource and that key organizations lack adequate authority to take appropriate local responsibility.[92]

3.5 Disclosure of hydraulic fracturing chemicals

B.C. does not currently require companies to disclose the chemicals and additives used in hydraulic fracturing operations, either to the regulator or to the public. The Oil and Gas Commission's factsheet, *Fracturing (Fracing) and Disposal of Fluids*, makes no mention of any potential dangers, chemical additives or toxic materials that could be included in fracturing fluids.[93] Similarly, the National Pollutant Release Inventory, which is a federal public inventory of pollutant releases (including underground injections), expressly exempts oil and gas exploration and drilling activities from its reporting requirements.[94]

However, the Oil and Gas Commission has been aware of increasing public demand for disclosure of the chemicals used in hydraulic fracturing operations and the growing likelihood that disclosure will be required by various federal and state regulators in the United States. In June 2010, the Oil and Gas Commission said it was anticipating changes to the provincial Oil and Gas Activities Act that would "...enable the Commission to require reports and analysis on all oil and gas activities, including components of fracturing fluids."[95]

Those changes have been made and the Oil and Gas Activities Act now gives the Commission the power to require companies to disclose the chemicals used in hydraulic fracturing but the information has not yet been requested from companies. A recent announcement from B.C. Premier Clark stated that the province would create a publicly accessible online registry to show where hydraulic fracturing activities are taking place, and provide detailed information about the practices and additives used during these activities.[96] The details of how the registry will operate and any new data that it will contain were not included with the announcement. The Canadian Association of Petroleum Producers supports the disclosure of fracturing fluid additives.[97]

3.6 Disposal of flowback water

Companies operating in B.C. are required to dispose of wastewater from shale gas wells by deep well injection (e.g., injected into old gas wells) or can elect to transport it to an approved treatment facility, which would be regulated under the province's Environmental Management

[92] B.C. Auditor General, "An Audit of the Management of Groundwater Resources in British Columbia. Report 8", December 2010. Executive Summary.

[93] B.C. Oil and Gas Commission, "Fracturing (fracing) and disposal of fluids fact sheet," 2010, http://www.bcogc.ca/documents/publications/Fact%20Sheets/Fracturing_and_Disposal_of_Fluids_FINAL.pdf

[94] Environment Canada, "Guide for reporting to the National Pollutant Release Inventory," section 3.2.2, 2009, http://www.ec.gc.ca/inrp-npri/default.asp?lang=En&n=C07CFADA-1

[95] B.C. Oil and Gas Commission, "Oil and gas water use in British Columbia," p. 18, 2010

[96] B.C. Government, Increased transparency for natural gas sector, news release, Sept. 2010, http://www.newsroom.gov.bc.ca/2011/09/increased-transparency-for-natural-gas-sector.html

[97] Canadian Association for Petroleum Producers, "Guiding Principles for Hydraulic Fracturing", Sept. 2011, http://www.capp.ca/getdoc.aspx?DocId=195096&DT=NTV

Act. We are not aware of any public information on the adequacy of these practices and are unable to comment on them.

3.7 Enforcement and compliance

Problems with enforcement and compliance in B.C.'s oil and gas sector have been previously documented. In 2005, an Ecojustice report noted that Oil and Gas Commission field inspection statistics in 2003 revealed that 62% of inspections identified infractions and that the rate was 64% in 2004. A joint agency audit (including provincial ministries and the federal Department of Fisheries and Oceans) revealed that 20% of activities were operating in disregard of the law or posed an immediate threat to the environment.[98]

Similarly, a recent report by the B.C. Auditor General on the Oil and Gas Commission's record of addressing contamination has been sharply critical.[99] Some of the conclusions that relate to compliance and enforcement include:

- The public information provided by the Oil and Gas Commission on its oversight activities is not sufficient to allow the Legislative Assembly and public to understand how effectively oil and gas site contamination risks are being managed (p. 6).
- That the Oil and Gas Commission's own reported compliance rate of 98% for the 2007/08 year was deficient for two main reasons: First, because it represented the state of compliance *only after* operators had taken steps within the prescribed time period to remedy deficiencies found during inspections and that the initial rate of compliance before corrections were made was not reported; Second, because the Oil and Gas Commission was unable to confirm how many inspection parameters checked related to site contamination risks (p. 10).
- That the Oil and Gas Commission does not report publicly on how many of the sites had at least one deficiency nor the number of inspections that involved a serious or major deficiency that had the potential to cause an adverse impact on the public, the environment or both (p. 11).

While many of these recommendations have been made in some form before, it is notable that the Auditor General is now recommending that:

> "...the Oil and Gas Commission improve its information collection system and public reporting in order to improve transparency and accountability, including information such as the general compliance rate, statistics before and after deficiencies have been corrected, the significance of non-compliance, the degree to which the non-compliance relates to site contamination and other categories of significant deficiencies, and whether the deficiencies have been rectified."[100]

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[98] Ecojustice (formerly Sierra Legal Defence Fund), "This Land is Their Land: An audit of the regulation of the oil and gas industry in B.C," p. 27-8, June 2005

[99] B.C. Auditor General, "Oil and gas site contamination risks: Improved oversight needed 2009/2010," report number 8, February 2010

[100] Ibid.

A brief comparison between Oil and Gas Commission Field Inspection reports from 2008/2009 and 2009/2010 reveals that while some of the issues identified in the Auditor General's report (such as the nature of the deficiency) are being addressed, non-compliance remains an ongoing concern.[101] As shown in Table 3, the number of wells drilled declined from 845 to 634 from 2008/09 to 2009/10 and the number of site inspections remained relatively constant at 4,337 (4,359 in the previous year). While the non-compliance rate declined, the review found that 17% of sites inspected were deficient and almost all of these deficiencies were in the "serious" or "major" category ("minor" being the third classification). It is also noteworthy that these non-compliant sites are only listed after requests to address the deficiencies have not been satisfied.

Table 3 — Selected Summary Data from the Field Inspection Reports

	2008/09	2009/10
Number of wells drilled	845	634
Number of site inspections performed	4,359	4,337
Total number of sites with deficiencies overdue[102]	1,130 or 25.9%	756 or 17.4%
Total number of sites with serious or major deficiencies overdue	1,047 or 24.02%	723 or 16.7%
Number of warnings issued	22	21
Number of prosecutions/tickets issued	26 or 0.69%	30 or 0.60%

One of the principles of a good compliance policy is that a variety of tools be available to the regulator, ranging from work orders and warnings through to prosecutions. The relatively high rate of sites with "serious" or "major" deficiencies overdue in combination with a very low rate of prosecution (less than one per cent) raises serious concern that the full range of tools is not being adequately deployed to deter and penalize violations.

A recent review by West Coast Environmental Law found that in 2009 the Ministry of Environment had the lowest level of environmental convictions in 20 years.[103] One of the main reasons cited by West Coast Environmental Law is extensive budget cutbacks and reduced staffing levels that have become the norm in the past 10 years, making it more difficult for prosecutions to be pursued.

One effective element of the Ministry of Environment practice is the Quarterly Compliance and Enforcement Summaries, which name individual polluters and the nature of the action taken against them.[104] In contrast, the Oil and Gas Commission Field Inspection reports merely list infractions but not the names of companies or the specifics of the actions taken against them. This additional level of detail would help to increase public understanding of the nature of oil and gas industry non-compliance and also provide a better sense of which companies are

[101] B.C. Oil and Gas Commission, "2009/10 BC Oil and Gas Commission Field Inspection Annual Report," p. 9, 2010

[102] An "overdue" deficiency is described in the reports as a situation in which the operator had already been asked to remedy a deficiency but the deficiency had not been remedied in the allotted time frame.

[103] West Coast Environmental Law, "BC fails to halt collapse in environmental enforcement in 2009," 2010, http://wcel.org/resources/environmental-law-alert/bc-fails-halt-collapse-environmental-enforcement-2009

[104] See http://www.env.gov.bc.ca/main/prgs/compliancereport.html#2010

exhibiting poor performance. The current lack of transparency is completely inappropriate and hinders the improvement of industry practice.

4. Developments in other jurisdictions

In the United States, hydraulic fracturing techniques have been used for years and have recently become the source of increased controversy. In response to increased activity by the industry throughout the U.S., there have been calls for both improved government oversight and for the disclosure of the chemicals that are used in hydraulic fracturing. The adequacy of the information disclosed to the public about these chemicals and the risk they pose to human health and the environment has been a major issue in the United States.[105] Similar questions are being raised in other jurisdictions where shale gas extraction has been proposed (e.g., France and Quebec). Changes at both the federal and sub-national levels are strengthening government understanding and oversight of shale gas activity.

4.1 Disclosure

As of September 2010, the State of Wyoming requires companies to submit a full list of the chemicals they plan to use during fracturing operations for each individual well. Once fracturing operations are completed companies must report the concentrations of each chemical used. These are amongst the most stringent disclosure requirements in the US.

Colorado was the first state to require companies to disclose chemicals used in fracturing operations, beginning in 2008. The rule requires that companies disclose the chemicals used in fracturing fluids to health officials and regulators — but not the public. This disclosure is only required for chemicals stored in 50 gallon drums or larger.[106] Operators are also required to report to the state regulator any loss of hydraulic fracturing fluids.

Federally, the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, introduced by Representative Dianne DeGette of Colorado, as well as the Clean Energy Jobs and Oil Company Accountability Act would both require oil and gas operators to disclose the chemicals used to fracture wells. The FRAC Act would also amend the Safe Drinking Water Act to include hydraulic fracturing in its definition of underground injection. The Independent Petroleum Association of America (IPAA) claims that if hydraulic fracturing is regulated under the Underground Injection Control (UIC) provisions of the Safe Drinking Water Act that there would be an incremental cost of approximately $100,000 per unconventional well.[107]

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[105] M. Zoback, S. Kiasei & B. Copithorne, "Addressing the environmental risks from shale gas development," Worldwatch Institute, July 2010

[106] Department of Natural Resources, *EPA Public Hearing,* State of Colorado Oil and Gas Conservation Commission, Denver, Colorado, July 12, 2010

[107] Advanced Resources International, "Bringing Real Information on Energy Forward – Economic considerations associated with regulating the American oil and natural gas industry," prepared for the Independent Petroleum

The Quebec government is intending to require disclosure of the composition of fracture fluids to regulators along with other information including full details of water withdrawals,[108] although it is not yet clear how much of this information will be accessible by the public.

The website fracfocus.org provides a public database that discloses the chemicals used in hydraulic fracturing operations. Industry decisions to provide information to the database are voluntary.

Improvements in the disclosure of chemical use could be accomplished relatively easily in B.C. given the regulatory authority already exists in the Oil and Gas Activities Act. Similarly, the improvements could be made nationally by removing exemptions for oil and gas drilling and exploration activity in the National Pollutant Release Inventory. See Section 3.5 for further discussion.

4.2 Hydraulic fracturing moratoriums

In 2010, Quebec's environment minister mandated high-profile public hearings for proposed shale gas development in the province.[109] In accordance with the report from the hearings the minister has now launched a "strategic" environmental assessment of the development of the province's shale gas resources. The assessment is expected to take about two years, during which time the minister will only authorize hydraulic fracturing operations if they are recommended for research purposes by the expert committee undertaking the assessment.[110]

Similar moratoriums have been implemented in South Africa[111], Maryland[112] and France[113]. The State of New York had implemented a temporary moratorium that expired on May 15, 2011.[114] New proposed draft rules following the ban would prevent drilling in the New York City and Syracuse watersheds but allow activity in the remainder of New York's portion of the Marcellus shale.[115]

Association of America and the Liaison Committee of Cooperating Oil and Gas Associations, p. 17, Table 3, April 24, 2009, http://www.energyindepth.org/PDF/Brief/BRIEF-Economic-Consequences.pdf

108 Ministère du Développement durable, de l'Environnement et des Parcs, "Évaluation environnementale stratégique — Adoption des mesures transitoires," media release, May 5, 2011, http://www.mddep.gouv.qc.ca/infuseur/communique.asp?no=1855

109 Bureau d'audiences publiques sur l'environnement, "Développement durable de l'industrie des gaz de schiste au Québec", March 23, 2011, http://www.bape.gouv.qc.ca/sections/mandats/Gaz_de_schiste/

110 Ministère du Développement durable, de l'Environnement et des Parcs, "Composition du comité de l'Évaluation environnementale stratégique," media release, May 12, 2011, http://www.mddep.gouv.qc.ca/infuseur/communique.asp?no=1857

111 S. Tavanger, "South Africa imposes fracking moratorium," *Platts Energy Week,* April 25, 2011, http://plattsenergyweektv.com/story.aspx?storyid=147836&catid=293

112 Maryland General Assembly, "House Bill 852," 2011, http://mlis.state.md.us/2011rs/billfile/hb0852.htm

113 T. Patel, "The French Public Says No to '*Le Fracking*'," *Bloomberg Businessweek*, March 31, 2011, http://www.businessweek.com/magazine/content/11_15/b4223060759263.htm

114 New York State Assembly, "Assembly Passes Moratorium on Hydrofracking", media release, November 30, 2010, http://assembly.state.ny.us/Press/20101130/

115 New York State Department of Environmental Conservation, "Marcellus Shale," http://www.dec.ny.gov/energy/46288.html

5. Recommendations

The previous sections have raised a number of concerns relating to the water impacts associated with shale gas development in British Columbia as well as gaps in the way they are currently planned for and regulated. In order to ensure that B.C. understands and manages these water risks responsibly, the Pembina Institute recommends that the B.C. government:

1. Develop water management plans for the Montney and Horn River basins. Ideally, the management plan would include all major users (i.e., not limited to the oil and gas industry), and the plans should articulate a pace and scale of development that limit cumulative effects such that water resources are adequately protected. These plans could be one of the outcomes of the Water Act Modernization process, which has proposed establishing Provincial Water Objectives to guide decision-making.[116] The plans should:
   - Require approvals of industrial projects (such as natural gas production) to be consistent with the limits on impacts, as measured by the monitoring program. It is possible that these requirements would reduce proposed development relative to current business as usual projections.
   - Require frequent monitoring and public reporting of cumulative impacts to ensure that water users, local communities, First Nations and governments have a complete picture on the impacts that are occurring. Some of this data is already collected by various agencies (e.g., Oil and Gas Commission, B.C. government, First Nations, Local Governments, and or Bridgewater), but it is not available in a single location and there are some gaps.
   - Account for other emerging stressors to water resources such as projected changes in water flows caused by climate change.
   - Integrate with other cumulative effects of concerns such as greenhouse gas emissions. In combination these effects of concern could be managed collectively in a larger cumulative effects management system.
2. Provide timely, regularly updated and easily accessed public information on all water allocations, actual water withdrawals under permits, licences or other means, actual water uses and flowback water for the Montney and Horn River areas. The Ministry of Environment should manage the requirements. As with recommendation 1, some of these components are already in place, but a complete picture is not available. This reporting could ultimately be part of recommendation 1 but, given the complexity of getting regional water plans developed and implemented, this recommendation could be implemented relatively quickly with a modest amount of work.
3. Require water licences for all ground water withdrawals. Having this in place would fill a significant gap in terms of water allocation. Based on the most recent Water Act

[116] Government of British Columbia, *Policy proposal on British Columbia's new Water Sustainability Act*, page 8, December 2010, http://www.livingwatersmart.ca/water-act/docs/wam_wsa-policy-proposal.pdf

Modernization recommendation the province is intending to regulate currently unregulated groundwater users.

4. Place licensing powers and oversight for all water takings within a single ministry in the B.C. government. Based on current organizational structure, this would fall to the Ministry of Forests, Lands and Natural Resource Operations and would follow the current trend of attempting to centralize natural resource permitting decisions. Alternatively it could placed within the Ministry of Environment, which is where water licensing responsibility fell before the 2010 creation of the Natural Resource Operations ministry. Ultimately, the regulatory environment should help ensure that total water allocations are fairly distributed among human users and are respectful of environmental limits.
5. Require companies to publicly disclose chemicals and additives used in hydraulic fracturing. Increasingly, U.S. state regulators are requiring such disclosures, as is Quebec. Although the risk of contamination of fresh water by fracture fluids appears to be low in most settings, they are nonetheless being introduced into the environment in some cases and the public has a fundamental right to understand their composition. Responsible development of this resource means that people should have clear information on the nature and quantities of chemicals and additives that are being injected into the ground and present in produced water. Recent changes to B.C.'s Oil and Gas Activities Act and commitments from Premier Clark make this regulatory improvement very achievable in the near-term.
6. Undertake an independent audit of all oil and gas water use in B.C., seeking direct information from companies on actual water use and disposal including all currently untracked sources. The key purposes of this recommendation are to: assess the accuracy of company reporting, assess the degree of company compliance with permits and licences as well as to gain a better understanding of the scope and scale of water access arrangements being made with non-oil and gas users.
7. Undertake improved public mapping of groundwater to allow for informed environmental assessment of oil and gas exploration and production. Initial scoping should test the adequacy of the work that is ongoing in the Montney River and begin comprehensive work in the Horn River.
8. Ensure transparent and comprehensive compliance and enforcement including automatic prosecution for serious overdue deficiencies. In addition to the lack of information about the extent of water use there are also very few water stewardship staff available to ensure that water licences are adhered to and any non-compliance is meaningfully addressed. We also recommend that the amount of information provided in the Oil and Gas Commission Field Inspection Reports be expanded to include the names of the company responsible for episodes of non-compliance and the specific nature of the violation at issue and the action taken as a result. This practice is the case with the Ministry of Environment Compliance and Enforcement summaries.
9. Review, and strengthen as needed, requirements for drilling, hydraulic fracturing and water storage and disposal as well as the liability of producers in case of contamination. This study has not revealed any B.C.-specific concerns with those requirements but, given potentially significant growth in shale gas activity and a scale of hydraulic fracturing that B.C. has not experienced as well as some of the current gaps in scientific understanding about hydraulic fracturing, this type of proactive review would be wise.