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Shale Gas in Canada: Environmental Risks and Regulation

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(Background Paper)

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SHALE GAS IN CANADA: ENVIRONMENTAL RISKS AND REGULATION*

1 INTRODUCTION

The recent increase in the development of shale gas in North America has raised significant public concerns about associated environmental risks. After providing some background information about shale gas and its extraction, this paper offers an overview of some of the environmental impacts of shale gas development, and explains how Canada's current regulatory regime, most of which is provincial, addresses these impacts.

2 WHAT IS SHALE GAS?[1]

Shale gas is a natural gas resource trapped in impermeable shale rock. "Natural gas" refers to a mix of methane (typically about 85% of the total), other hydrocarbons (such as ethane, propane, butane, and pentane), carbon dioxide, and trace elements of nitrogen, helium and hydrogen sulphide.[2]

Shale gas requires special or unconventional production techniques to fracture the rock in which it is trapped, in order to free the gas and enable its flow.[3] In contrast, conventional natural gas can be easily accessed with a traditional vertical well, drilled directly into the reservoir.

3 HOW IS SHALE GAS EXTRACTED?

Shale gas can be extracted using a variety of techniques,[4] including those employed for conventional natural gas.[5] However, shale gas extraction typically involves both horizontal drilling and hydraulic fracturing (sometimes referred to as "fracking"). While these two techniques have existed separately for decades, their combined use is relatively new and largely responsible for making shale gas commercially viable.

3.1 HORIZONTAL DRILLING

In North America, horizontal drilling became commercially viable in the 1980s, and has been used to increase production volumes from all types of natural gas and oil wells.[6] For shale gas, horizontal drilling begins with the drilling of a vertical well into the earth's surface until it reaches the shale rock, which is typically 1.5 km to 4.0 km below ground.[7] Once the targeted rock is reached, the drill bit is turned along a horizontal trajectory for 1.0 km to 3.0 km.[8] Multiple horizontal wells are often drilled from one vertical well to increase production and reduce land-use impact.[9]

When drilling the well, multiple lengths ("strings") of steel casing are lowered into the wellbore to different depths and cemented into place, creating several layers of steel and cement between the inside of the well and the surrounding environment.[10] These cementing and casing techniques are used in all types of oil and natural gas wells.[11]

3.2 HYDRAULIC FRACTURING

Hydraulic fracturing has been used in conventional oil and gas wells for over 60 years.[12] This technique involves pumping a fluid down the well at high pressure. Fluid composition varies based on the type of rock, specifications of the well, and fracturing stage.[13] Generally, 6.0% to 9.0% of the fluid is composed of proppant (synthetic or natural non-compressible granular material, usually sand)[14], and 0.5% to 2.0% comprises chemicals, with the rest (89.0% to 93.5%) being water.[15]

The pressure from pumping this fluid creates tiny cracks in the rock, and the proppant keeps them open. The fluid is then pumped back out, freeing the gas from the cracks and making it flow to the surface.[16] Each well is fractured multiple times, a process called multi-stage fracturing. Each stage requires a different fluid mixture.[17]

3.3 NUMBER OF SHALE GAS WELLS[18]

Table 1 presents the number of shale gas wells drilled by province as of 2011 (the most recent year for which comparable data are available).[19] At that time, British Columbia had the most wells, 1,873. Alberta had the next highest number, with 190 wells, then Saskatchewan, with 85 wells. Hydraulic fracturing was not used in all the wells in these provinces. Significantly fewer wells had been drilled in the rest of Canada. Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador have proposed or implemented some form of moratorium on shale gas development.[20]

Table 1 – Number of Shale Gas Wells Drilled per Province, up to 2011

	British Columbia[a]	Alberta	Saskatchewan	Ontario	Quebec	New Brunswick[b]	Nova Scotia
Drilled	1,873	190	85[c]	1[d]	29	4	5
Fractured	~1,873	178	~42	-	18	3	3
In production	1,354	114	35	-	-	1	-

Notes: a. Numbers for British Columbia should be taken as a minimum, because they only include wells from the Horn River and Montney basins.

b. In addition to shale gas wells, 46 tight-sand gas wells have been hydraulically fractured in New Brunswick and are currently producing.

c. About 35 of these wells were drilled for commingled production, meaning that both the shale rock and the sands of the Colorado group basin were the target of drilling.

d. The provincial government also drilled three other wells for research purposes.

Source: C. Rivard et al., *A review of the November 24–25, 2011 shale gas workshop, Calgary, Alberta – 2. Groundwater resources*, Geological Survey of Canada, Open File 7096, 2012, p. 3; and Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, *Environmental Impacts of Shale Gas Extraction in Canada*, Council of Canadian Academies, Ottawa, 2014.

As for the territories, there has been no exploration or production of shale gas in Yukon,[21] and Nunavut does not have any oil or gas production.[22] At least one company has conducted exploration activities using horizontal drilling and hydraulic fracturing in the Canol shale formation in the Northwest Territories, and it has applied for permits to expand those activities.[23] The formation is thought to include both natural gas and oil.[24]

4 WHAT ARE THE ENVIRONMENTAL RISKS AND ASSOCIATED REGULATIONS RELATED TO SHALE GAS DEVELOPMENT?

The environmental and socio-economic context varies considerably between (and within) regions, meaning that the extent of each risk will vary by province.[25] Details of these differences are beyond the scope of this document, but more information can be found in a report published by the Council of Canadian Academies (CCA).[26]

The subsections below present a broad overview of some of the potential environmental impacts of shale gas development in Canada and discuss regulations aimed at mitigating these impacts. The cited regulations, particularly at the regional level, are provided as illustrative examples and should not be considered as an exhaustive discussion of provincial and territorial[27] initiatives.

4.1 Effects on Water Resources

4.1.1 Quantity of Water Used

The total amount of water needed for shale gas development is generally small relative to annual total surface water flows.[28] The challenge is the need for large volumes of water over short time periods (several weeks to months), which could create stresses at certain peak times of the year. As explained by the CCA,

> Problems may arise at the driest time of the year when demand is highest for many water uses, at the coldest time when surface waters are mostly frozen and active flow is low, or during critical periods when water levels are important for access to critical habitats.[29]

For example, a Quebec study found that the province has enough water to meet the needs of shale gas extraction without having an impact on ecosystems or other water users, but identified certain low-flow areas that could not support withdrawals.[30]

Similarly, a report from Nova Scotia noted that the province would have sufficient capacity to supply water to the shale gas industry, except in certain areas of the province with extensive agricultural operations and limited surface water sources.[31]

Table 2 provides the average volume of water used per well in different Canadian shale gas “plays,” which is the term industry sometimes uses to describe a shale formation. Numbers vary significantly between regions because of the different geological characteristics of the rock.[32] The numbers range from a low of 0.2 million litres in the Colorado play to a high of 76.9 million litres in the Horn River Basin play.

However, data in Table 2 are broad averages, and individual wells may fall outside these ranges. Some wells in the Horn River Basin, for example, use up to 80 million litres because of the very thick rock in that play.[33]

Table 2 – Average Volume of Water Used per Well in Shale Gas Plays in Canada

Shale Gas Play	Average Volume of Water per Well (millions of litres)
Horn River Basin (British Columbia)	76.9
Montney (British Columbia)	6.7–9.7
Colorado (vertical wells in Saskatchewan)	0.2–0.4
Utica (Quebec)	12.0–20.0
Frederick Brook (New Brunswick)	2.0–20.0
Horton Bluff (Nova Scotia; two wells only)	5.9–6.8

Source: Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, *Environmental Impacts of Shale Gas Extraction in Canada*, Council of Canadian Academies, Ottawa, 2014.

Compared to most other fossil fuels, shale gas uses less water for production on average (see Table 3). However, as noted above, shale gas production does use a lot of water in a short period.

Table 3 – Water Consumption of Fossil Fuel Activities

Fossil Fuel	Water Consumption (gallons per million British thermal unit)[a]
Shale gas	0.6–1.8
Oil (primary production)	1.4
Oil (secondary and enhanced oil recovery)	62–65
Oil sands	13–33
Conventional natural gas	0 (approximate)

Note: a. A British thermal unit is a measure of the heat needed to raise the temperature of one pound of water by one degree Fahrenheit. For more information, see United States Energy Information Administration, "What are Ccf, Mcf, Btu, and therms? How do I convert natural gas prices in dollars per Ccf or Mcf to dollars per Btu or therm?," *Frequently Asked Questions*.

Source: Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, *Environmental Impacts of Shale Gas Extraction in Canada*, Council of Canadian Academies, Ottawa, 2014.

The water used in hydraulic fracturing can be from one of the following sources: fresh water (lakes, streams, groundwater, etc.); recycled flowback water;water from a saline aquifer or co-produced with oil; municipal wastewater after primary treatment; or municipal water.[34] Currently, fresh water is the main source used, though some companies are switching to using recycled flowback water.[35]

4.1.1.1 Regulation of Water Allocation

In Canada, provinces and territories are responsible for allocating water, with each having its own regime for authorizing water withdrawals for various uses.[36] Certain provinces have recently updated their requirements related to water withdrawals, some of which apply specifically in the context of hydraulic fracturing.

For example, in 2012, Alberta revised a directive to include

> [n]ew requirements for … electronically reporting water source data, including source location, source type, diversion permit information, and volume for all water used in hydraulic fracturing operations with water quality information required for groundwater sources.[37]

In New Brunswick, rules for industry published in 2013 require a well operator that intends to withdraw water for use in hydraulic fracturing to have an approved water management plan to support water conservation and recycling. The rules also require operators to monitor in-stream flows at withdrawal locations and to record and report water use.[38]

4.1.2 Risk of Groundwater Contamination

4.1.2.1 Naturally Occurring Methane

The discussion of risks to groundwater from shale gas production is complicated by the variety of possible sources of contamination, such as the methane that can naturally occur in groundwater. For example, a study in Quebec found naturally occurring methane in 95% of the sampled drinking water wells.[39] In Nova Scotia, a study found methane in 21% of all wells owned and operated by the province.[40]

Naturally occurring methane and a lack of pre-drilling baseline data make it difficult to establish causality between shale gas extraction and increased levels of methane in groundwater wells.[41] It may be difficult or impossible to obtain this baseline data once shale gas development has already started.[42]

4.1.2.2 Vertical Migration of Fracking Fluid into Aquifers

Another identified source of contamination is the upward migration of fracturing fluid through fractures into aquifers. Available evidence suggests that this risk is remote, given the distance between the fractures and the aquifers, and the sustained pressure that would be required for fracking fluid to migrate upwards.

Shale rock is typically 1.5 km to 4.0 km below the surface. According to the CCA, the vertical reach of fractures can be up to 0.3 km from the shale rock,[43] but a United Kingdom study of thousands of fracturing operations across the United States found one about 0.6 km in height.[44] This may be compared with the fresh groundwater zone, which is an estimated 0.1 km to 0.3 km below the surface, but may be as deep as 0.6 km.[45]

For example, a study from Quebec suggested that there are minimal risks of contamination either from natural or from human-induced fractures, but the study also noted that the importance of these risks can be difficult to determine because of a lack of data.[46]

These findings suggest that the possibility of fractures reaching as far as the overlying aquifer is unlikely.[47] Even if the vertical fractures were to reach the groundwater aquifer, sustained pressure conditions would be required for fracking fluid to flow upward through the fractures.[48]

However, there is a knowledge gap about whether hydraulic fracturing can open existing fractures in the rock, providing a pathway for the vertical migration of naturally buoyant gas. Field measurements and long-term monitoring are needed to address this knowledge gap, and the CCA suggests that such an analysis has not occurred.[49]

4.1.2.3 Contamination Through Faulty Well Construction and Integrity

A study from Quebec suggests that the most significant risks to groundwater contamination involve well construction.[50] These risks are not unique to shale gas production, and were first identified in the 1970s.[51] Few definitive studies exist on the frequency, severity and consequences of well integrity failure.[52]

The CCA has identified a number of challenges for proper well cementation:

- Enough cement must be used to reach an appropriate depth, cover the well casing, and displace mud between the casing and borehole.
- Cement must be distributed over the entire length of casing.
- Cement must be properly bonded to the casing and rock.
- Gas must not migrate into cement while it is setting.
- The casing must stay centralized in the borehole while cementing occurs.[53]

Many other circumstances may result in inadequate casing cementation, such as improper cement formulation and incomplete drilling fluid displacement. Over time, cement can also crack, shrink or become deformed.[54]

The challenge of well integrity is amplified by the potentially high number of wells associated with large-scale development of shale gas and the chemical additives used in fracturing fluids. Furthermore, achieving high-quality casing cementation is universally acknowledged as being more difficult for inclined casing (such as horizontal wells).[55] Leaky wells have been reported in western Canada's conventional oil and gas sector, and in abandoned shale gas wells in Quebec.[56]

Modern cementation practices are about 60 years old. As a result, the long-term integrity of wells is poorly understood, and further analysis is required to evaluate the risks and identify mitigation measures.[57] It is not known how long a sealed well will maintain its integrity after decommissioning.

A report from Nova Scotia suggests that there is no evidence of major increases in the incidence of leaky wells over time, but studies have not systematically examined old well sites to quantify these risks over the long term (i.e., 100 years or more).[58]

Abandoned wells may also pose a risk. This could occur if they are located near wells currently used for production and the formations that they penetrate become re-pressurized from either shale gas production or deep-well disposal of flowback water. Such "communication" between wells may lead to the unintended discharge of water, gas, mud or sands into aquifers or to the surface. In British Columbia, 18 such communications have occurred, while 20 have occurred in Alberta.[59]

According to the CCA, the oil and gas industry has substantially improved the practices used for the cement sealing of wells over the past decade.[60] The number of wells that display high-rate leaks and the average leakage rates are low.[61] However, the CCA also noted that the extent of improvements claimed by the industry has not been independently verified, and a continuing effort is needed to improve cementation.[62]

4.1.2.4 Regulation of Groundwater Contamination

The protection of groundwater from contamination is regulated primarily by the provinces. Some provinces require baseline groundwater testing before fracking occurs. For example, in British Columbia, pre- and post-fracture sampling of water wells within 200 metres (m) of proposed fracturing operations is required – when agreed to by water well owners – before a company may fracture at depths shallower than 600 m.[63] In New Brunswick, oil and gas drilling may not begin before water samples have been collected and analyzed from all water wells within 500 m of the drilling site.[64]

To protect aquifers from contamination, provinces and territories have adopted requirements and guidelines for well drilling, completions, maintenance and abandonment. [65] Such requirements apply both to conventional oil and gas wells and to unconventional wells.[66] In 2013, Alberta released a new directive setting out requirements for “managing subsurface integrity associated with hydraulic subsurface operations.”[67]

4.1.3 Risks from Operational Practices

4.1.3.1 Use of Hazardous Chemicals

The risk to water quality from developing shale gas is often related to operational practices, rather than to the process of fracturing and extraction. A 2014 report of the Nova Scotia Independent Review Panel on Hydraulic Fracturing summarizes the main operational risks to surface water and groundwater:

- Accidental spills of chemicals, oils, drilling muds, and fracture fluids during transportation, storage, or use;
- Spills of condensates (where these are present) or flowback or produced water from the producing well; and
- Inadequate storage, treatment, or disposal of flowback water, which includes both fracturing fluids and saline formation water, and leaks from surface storage ponds or other storage facilities.[68]

Most of these operational risks involve spills of the various substances used during the hydraulic fracturing process that could potentially contaminate water and soil (the same could be said about chemicals used in any industrial process).[69] If a spill or leak occurred during the storage, mixing, or pumping of these fracturing fluids, the fluids could then flow into nearby surface water or infiltrate the soil.[70]

Additives used in fracture fluids can include both chemicals commonly found in consumer products and those that may be harmful to human health. Environment Canada and Health Canada have compiled a partial list of over 800 substances known or suspected to be used for hydraulic fracturing in the U.S. and Canada.

Of these substances, 33 have been assessed as toxic in other applications (e.g., benzene in gasoline).[71]

Although the concentration of chemical additives in fluids can be small (0.5% to 2.0% by volume), the large quantities of water required for fracturing operations means that the use of chemicals is proportionally large.[72] One simulation concluded that, in the absence of recycling, supplying chemicals could require about 200 truck trips over a 50- to 80-day period.[73] Spills of these chemicals during transportation are a potential source of water contamination in shale gas development.[74]

The possible effects of contamination of surface and subsurface waters by fracturing chemicals are not well understood. According to the CCA, better assessment of each chemical in fracturing fluid is needed. It also suggests that there is a need to assess how the chemicals behave as mixtures, as well as the potential products that are created when the chemicals are mixed with water under field conditions.[75]

4.1.3.2 Storage and Treatment of Wastewater

Given the hazardous chemicals used in fracturing fluid, handling wastewater is a key issue. About 50% to 80% of the fracturing fluids return to the surface.[76] This flowback water contains the returning fracturing fluid, along with water from the formation, naturally occurring radioactive materials, metals and organic compounds.[77] As noted above, spills or leaks of wastewater are a possible operational risk.[78]

After being stored in lined surface ponds or tanks, flowback water may be:

- treated on or off site in a specialized treatment plant;
- reused to fracture another well; or
- re-injected into a deep saline formation.

Lined ponds are rarely flawless and can be expected to leak over time.[79] Surface ponds can overflow after heavy rain.[80]

Specialized treatment plants are required to treat flowback water, as municipal treatment plants are often not equipped to treat the water from shale gas operations.[81] Safe and effective disposal of flowback fluid is especially challenging if it contains high concentrations of radioactive materials and other toxic elements.

The re-use of wastewater for further fracturing is generally increasing, with an estimated 70% of wastewater being re-used in 2011. While this practice may decrease the water quantity needed for fracturing operations, it results in more concentrated wastewater, which will still require treatment or storage.[82]

Where geological conditions permit, wastewater can be injected into saline aquifers or abandoned gas or oil wells to store deep underground. Industry prefers this option, in part because of the high costs of treating flowback water to achieve ecological and human health and safety standards.[83]

Deep-well disposal involves injecting waste fluids into "permeable porous formations that are specifically targeted to accommodate large volumes of fluid."[84] The wells used for disposal are sometimes shallower than the wells used for production, but are still much deeper than the freshwater aquifers. Conditions in western Canada are typically more conducive to deep-well disposal of flowback fluids. No wastewater disposal wells currently exist in Quebec, New Brunswick or Nova Scotia.[85]

4.1.3.3 Regulation of Hazardous Chemicals and Wastewater

Concerns have been raised about the toxicity of fracking fluids and the lack of public information about what chemicals are being used in fracking.[86] Jurisdiction to require disclosure of this data is shared between the federal and provincial governments.

The federal government recently considered and rejected the possibility of requiring companies to report fracturing fluid chemical use to the National Pollutant Release Inventory under the *Canadian Environmental Protection Act, 1999* (CEPA 1999).[87]

Provincially, since January 2012, British Columbia has required operators to disclose the hydraulic fracturing fluids being used.[88] To facilitate public disclosure, the province launched the website FracFocus.ca, which was designed to accommodate other jurisdictions' participation in order to provide a single window for accessing fracturing fluid information nationwide.[89] Fracturing fluid information from Alberta, New Brunswick and the Northwest Territories is now available on FracFocus.ca.

Under CEPA 1999, Environment Canada and Health Canada have an obligation to assess every new chemical substance made in Canada or imported into Canada, including chemicals used in fracking, to determine whether it is toxic. Substances found to be toxic are then managed following the Toxics Management Process, which may result in the substance being regulated.[90]

Primarily, provinces regulate practices related to storage, handling and disposal of chemicals, wastewater and other substances associated with oil and gas activities.[91]

4.2 Effects on Air

The effects of increased shale gas production on air depend on:

- the extent to which shale gas displaces other energy sources;
- the quantity of methane emissions from gas leakage at the wellhead and in the distribution system;[92] and
- the extent of emissions related to transportation for gas production.

Shale gas operations can also cause a local increase in air pollution.

4.2.1 Natural Gas as a Substitute for Other Energy Sources

Natural gas burned using common technological means is cleaner than other fossil fuels, and it emits fewer pollutants, such as carbon dioxide (CO_2), into the atmosphere. Proponents of shale gas argue that this natural gas resource could displace other fossil fuels, particularly coal, thus reducing pollution. Others, however, suggest that emissions are worse when entire life cycle (i.e., well to burner) emissions are taken into account.[93]

Unlike the U.S. and China, which depend heavily on coal for electricity, Canada generates only 12% of its electricity using coal.[94] Natural gas already accounts for an important share (50% in 2011) of heating fuel, with oil representing only 7%.[95] Substitution possibilities are thus limited compared to other countries, though opportunities do exist in certain provinces.[96]

4.2.1.1 Regulation of the Energy Mix

A variety of regulations can affect the energy mix and the contribution of natural gas. Ontario has banned the use of coal at certain electrical generating facilities, and it is contemplating legislation that would extend the ban to all electrical generation.[97] The federal government has created regulations to ensure that new coal-fired plants (those that go into production on or after 1 July 2015) meet the performance standard of Natural Gas Combined Cycle technology, "a high-efficiency type of natural gas generation."[98]

Provincial regulations that place a price on carbon, such as the cap and trade system in Quebec,[99] the greenhouse gas (GHG) emission intensity targets in Alberta[100] and the carbon tax in British Columbia,[101] may also affect the energy mix if the additional cost is sufficient to make electricity generators decide to switch to another, less carbon-intensive source of energy. Whether the regulations would induce a switch to natural gas, however, would depend on the economic viability of all the alternatives.

4.2.2 Fugitive Emissions

The discussion of potential to substitute natural gas for other fossil fuels focuses on CO_2 emissions. However, CO_2 from burning natural gas is not the only GHG source to consider. Methane is also a potent GHG. While methane has a shorter lifetime in the atmosphere than other GHGs, it is more efficient at trapping radiation, with a 20 times greater impact than CO_2 on climate change over a 100-year period.[102]

The difference in GHG emissions between shale gas and coal depend largely on the life cycle methane leakage. However, life cycle analyses of the emissions from shale gas offer conflicting results.[103] Sparse data exists on methane leakage, and there is uncertainty about the accuracy of the methods used to produce that limited data.[104]

According to the CCA, "the primary knowledge gap related to the impact of GHG emissions associated with shale gas development stems from the uncertainty in estimating the total methane emissions themselves."[105]

Wells have multiple potential leak sources, and few have been studied for emissions; calculations are usually based on models rather than empirically observed data.[106] Leakage estimates can vary significantly based on the different values chosen for variables in the model.[107]

Current scientific literature suggests that fugitive methane emissions from shale gas can range from 0.5% to 8.0% of the extracted gas.[108] At the low end of these estimates, emissions from shale gas are similar to conventional gas, giving shale gas an advantage over coal. But at the high end, methane leakage may negate the benefits of shale gas over coal.[109] Estimates suggest that leakage rates must be below 2.7% to make substituting shale gas for coal an effective means of reducing emissions.[110]

The particularities of certain shale gas plays can also influence the amount of emissions during development of the resource. For example, shale gas in British Columbia's Horn River Basin is high in CO_2 content; this CO_2 must be separated and disposed of before the gas is brought to market. If this process is not managed properly, the development of this particular basin could significantly increase CO_2 emissions.[111]

Technologies do exist to help capture or otherwise avoid fugitive emissions from all types of natural gas production, and introducing the most cost-effective options to capture emissions could save the industry about $164 million annually.[112]

4.2.2.1 Management of Fugitive Emissions

The Canadian Association of Petroleum Producers has developed a Best Management Practice for Fugitive Emissions Management,[113] which some provinces have adopted to guide industry in developing programs to detect and repair leaks.[114]

4.2.3 Greenhouse Gas Emissions Related to Transportation

Transporting water, which can account for up to 80% of a shale gas operation's transportation activity, is a major cost to industry and to the environment in the form of GHGs.[115] Over the course of developing a single hydraulically fractured well, there can be thousands of truck trips to deliver water, equipment and other materials to the site, in addition to the trips to remove extracted products and waste material.[116]

4.2.3.1 Regulation of Transportation Emissions

Regulations aimed at limiting GHG emissions from transportation are those common to all trucking activities. Two pertinent federal regulations have been made under CEPA 1999. The *Heavy-duty Vehicle and Engine Greenhouse Gas Emission Regulations*[117] enact common mandatory North American emission standards for new on-road heavy-duty vehicles and engines. In addition, the *Renewable Fuels Regulations*[118] seek to reduce GHG emissions by mandating 2% biodiesel content in all diesel fuels. While provinces have mandated higher renewable fuels standards[119] and can invoke their own emission standards, vehicle manufacturing is highly integrated in North America, making it impractical to implement more stringent regulations than those in place at the federal level.

4.2.4 Effects on Air Quality

Shale gas operations can cause a local increase in air pollution, with populations living within a kilometre or less of development being particularly affected.[120] Some U.S. towns have seen an increase in smog coinciding with the arrival of shale gas production.[121]

4.2.4.1 Regulation of Air Quality

Air quality is generally under provincial jurisdiction. Air emissions of toxic substances, such as CO_2 related to transportation, may be regulated at the federal level.[122]

In addition, *Canadian Ambient Air Quality Standards* have been set by the Canadian Council of Ministers of the Environment and subsequently incorporated as objectives under the CEPA 1999. The standards are not mandatory but act as triggers for local actions to improve air quality should they be exceeded.[123]

Air quality at shale gas operations is managed locally. For example, noting that truck traffic may increase noise and dust, the Alberta Energy Regulator (AER) states, "For concerns such as increased truck traffic, the AER will work with counties and municipalities by providing information about potential developments to support their preparation for increasing activity."[124] Other jurisdictions, including New Brunswick, are planning to monitor air quality specifically related to shale gas operations.[125]

4.3 Effects on Land

4.3.1 Land Use Impact

Shale reservoir development generally occurs on a larger scale than that of conventional gas reservoirs because:

- the reach of individual wells in low-permeability rock is far less than it is in highly permeable [i.e., conventional] rock; and
- the production of individual wells declines faster so more wells are needed to sustain a stable production rate.[126]

In other words, shale gas requires more pads to be built and wells to be drilled than would be needed to produce the same volume of gas from a conventional reservoir.

Well pads for a conventional oil or gas reservoir are typically 0.5 hectare (ha) to 1.0 ha in size, compared to 2.0 ha to 3.0 ha for a shale gas reservoir. A large pad is required to accommodate the drilling of multiple wells and the equipment, chemicals and sand used in the hydraulic fracturing process.[127] Supporting infrastructure[128] may also be needed, which can sometimes take up more land than the well pads.[129]

If shale gas development occurred in a forested area, land would need to be cleared for the required well pads and other infrastructure. In Quebec, an estimated 5,000 ha of land would be needed to fully develop the Utica shale play between Montréal and the city of Québec.[130]

Clearing of forested areas could fragment ecosystems and create transition zones between disturbed and undisturbed habitats. Both of these phenomena may disrupt an ecosystem's structure and function, while changing the physical environment and the availability of resources for wildlife.[131]

As technology improves, it will be possible to place more wells on a single pad, reducing the industry's footprint. Using more wells from a single pad can also increase the quantity of gas produced, because more rock can be accessed from each site.[132]

4.3.1.1 Regulation of Land Use Impact

Effective management of the impacts of shale gas development on land, as well as on other resources, entails two broad considerations:

- a project's cumulative impacts on a regional basis rather than on a project-by-project basis,[133] and
- how development proposals fit with regional land-use plans.[134]

Regarding cumulative impacts, some jurisdictions are moving from granting approvals for individual wells to considering entire projects – wells, storage and disposal proposals, roads, etc. – as a whole.[135] On a larger scale, the "area-based analysis approach" to evaluating oil and gas development proposals "gathers and analyzes existing information and data on development activities in identified areas to better inform regulatory decisions," according to the BC Oil and Gas Commission.[136] For example, as the report of the 2013 Energy and Mines Ministers' Conference points out, to monitor cumulative land-use impacts in areas with extensive oil and gas activity, "British Columbia has developed a standardized methodology for measuring surface disturbances."[137]

Regional land-use plans can help to establish protected areas that are not to be developed (particularly if the plan is created before considering applications for significant development). For areas that may be developed, plans can set thresholds and limits in anticipation of all types of possible development and stressors.[138] Regulators may then make decisions and set conditions on applications that are consistent with achieving plan objectives.[139]

4.3.2 Induced Seismicity[140]

4.3.2.1 Hydraulic Fracturing

Hydraulic fracturing can induce seismic activity. Small earthquakes are a routine feature of hydraulic fracturing because of the energy released in the fracturing process.[141] Typically, they can only be detected with highly sensitive equipment in monitoring wells.[142] The fact that, of the more than 4,000 earthquakes recorded each year by the Geological Survey of Canada, 50 are generally felt, seems to bear this out.[143]

Large earthquakes from hydraulic fracturing are rare, but they can occur if there is a pre-stressed fault.[144] A very small fraction of injection and extraction activities at the hundreds of thousands of oil and gas wells in the U.S. have induced seismicity noticeable to the public.[145] None of these earthquakes has registered a magnitude of more than 4.[146] This can be compared with the June 2010 Val-des-Bois, Quebec, earthquake, also felt in parts of Ontario and the U.S., which had a magnitude of 5.[147]

In northern British Columbia, 272 seismic events occurred near areas of oil and gas development between April 2009 and December 2011, ranging between 1.0 and 3.8 in magnitude.[148] No injuries or property damage resulted from the earthquakes, and only one of these events was felt at the ground surface. All of these earthquakes were a result of injecting fracturing fluid near existing faults.[149]

In Quebec, the Utica shale play is located in a stable geological area not prone to seismicity. The few fracturing operations conducted in the province have not caused earthquakes.[150]

4.3.2.2 Injection of Wastewater

Injecting wastewater into disposal wells is more likely to cause earthquakes than is hydraulic fracturing. Wastewater injection also creates earthquakes of a higher magnitude.[151] Scientists from the U.S. Geological Survey found that the increase in seismicity in several states coincided with the injection of wastewater into disposal wells.[152] The earthquakes in the study were felt, but rarely caused damage.

Studies published in 2014 from Oklahoma and the Raton Basin of New Mexico and Colorado also identify the injection of wastewater in deep disposal wells as a potential cause of induced seismicity. [153] The largest earthquake that may have resulted from wastewater injection occurred in Prague, Oklahoma, in 2011 and was 5.7 in magnitude; it destroyed 14 homes and injured two people.[154] A study from Alberta found that a disposal well in the Western Canada Sedimentary Basin likely induced earthquakes.[155] Wastewater injection has also been linked to seismicity in British Columbia.[156]

Overall, induced seismicity from wastewater injection is still considered to be uncommon.[157] For example, the CCA notes that 140,000 wastewater injection wells have been drilled in the U.S. with relatively few seismic problems.[158]

4.3.3 Regulation of Induced Seismicity

Concerns over induced seismicity vary depending on the presence of geological formations vulnerable to seismic activity. Therefore, regulations in each jurisdiction also vary, but they generally focus on monitoring and reporting.

Smaller earthquakes are often monitored by companies to gather information about the nature of a formation. Companies may be obliged to submit such information to the regulator,[159] but the information is often proprietary and therefore not made public. In British Columbia, permit conditions include reporting on significant seismic events and suspending operations if warranted. The province plans to place these permit requirements in regulations.[160] Governments in all jurisdictions are increasing their monitoring of earthquakes, in cooperation with other jurisdictions, universities and stakeholders.[161]

5 CONCLUSION

The expansion of shale gas development is relatively new and its environmental impacts not completely understood. While some of the adverse impacts may be mitigated or addressed through oil and gas regulations of general application, other impacts are unique to shale gas development and require tailored regulation. The economic potential of shale gas development, coupled with the high level of public scrutiny and concern about related environmental impacts, will continue to drive research and study into the environmental effects of shale gas, as well as the evolution of regulations to mitigate its impacts.

NOTES

∗ Milana Simikian, formerly of the Library of Parliament, contributed to this paper.

1. For more information on this question, see Jed Chong and Milana Simikian, *Shale Gas in Canada: Resource Potential, Current Production and Economic Implications*, Publication no. 2014-08-E, Parliamentary Information and Research Service, Library of Parliament, Ottawa, 30 January 2014.

2. Cape Breton University, Verschuren Centre for Sustainability in Energy and the Environment [CBU], *Report of the Nova Scotia Independent Review Panel on Hydraulic Fracturing*, August 2014, p. 57.

3. Susan L. Sakmar, "The Global Shale Gas Initiative: Will the United States Be the Role Model for the Development of Shale Gas Around the World?," *Houston Journal of International Law*, Vol. 33, No. 2, Spring 2011; and ExxonMobil, "FAQs," *EuropeUnconventionalGas.org*.

4. For example, some shale formations can only be accessed with vertical wells because there is a risk of the wellbore collapsing. (National Energy Board, *A Primer for Understanding Canadian Shale Gas – Energy Briefing Note*, November 2009.)

5. Alberta Energy, *Shale Gas*.

6. Lynn Helms, "Horizontal Drilling," *North Dakota Department of Mineral Resources Newsletter*, Vol. 35, No. 1; and Sakmar (2011).

7. Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction [Expert Panel], *Environmental Impacts of Shale Gas Extraction in Canada*, Council of Canadian Academies, Ottawa, 2014, p. 44.

8. Ibid., p. 37.

9. International Gas Union [IGU], *Shale Gas: The Facts about the Environmental Concerns*, June 2012; and Ground Water Protection Council and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, Prepared for the United States Department of Energy, Office of Fossil Energy, and National Energy Technology Laboratory, April 2009.

10. Expert Panel (2014), pp. 42–43; and FracFocus Chemical Disclosure Registry, *Well Construction & Groundwater Protection*.

11. Canadian Association of Petroleum Producers [CAPP], *CAPP Hydraulic Fracturing Operating Practice: Wellbore Construction and Quality Assurance*, December 2012; and Canadian Society for Unconventional Gas, *Shale Gas in Canada: An Overview*, October 2010.
12. Office of the Auditor General of Canada – Commissioner of the Environment and Sustainable Development [CESD], "Chapter 5: Environmental Petitions," *Report of the Commissioner of the Environment and Sustainable Development*, Fall 2012; Thomas W. Merrill, "Four Questions About Fracking," *Case Western Reserve Law Review*, Vol. 63, No. 4, Summer 2013; and Natural Resources Canada [NRCan], *Shale Gas*.
13. Ground Water Protection Council (2009).
14. Expert Panel (2014), p. 225.
15. Ibid., p. 51.
16. Merrill (2013).
17. Sakmar (2011); and IGU (2012).
18. A map of Canada's main shale gas plays (the term industry sometimes uses to describe a shale formation), along with estimates of gas in place, can be found in the appendix in Chong and Simikian (2014).
19. British Columbia, for example, has more recent numbers for the Horn River and Montney basins. See BC Oil and Gas Commission, *Horn River Basin Unconventional Shale Gas Play Atlas*, June 2014; and BC Oil and Gas Commission, *Montney Formation Play Atlas NEBC*, October 2012.
20. In Nova Scotia, for example, the proposed moratorium would only apply to "high volume hydraulic fracturing for onshore shale gas." See Nova Scotia, "Government to Prohibit Hydraulic Fracturing," News release, 3 September 2014; Expert Panel (2014), p. 27; Newfoundland and Labrador, "Minister Announces Independent Panel for Review of Hydraulic Fracturing," News release, 10 October 2014; and New Brunswick, "Government introduces moratorium on hydraulic fracturing in New Brunswick," News release, 18 December 2014.
21. A committee from Yukon's Legislative Assembly reported on the risks and benefits of hydraulic fracturing in January 2015: Yukon Legislative Assembly, *Final Report of the Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing*, January 2015.
22. Yukon Energy, Mines and Resources, *Oil and Gas Resources*; and Aboriginal Affairs and Northern Development Canada, *Northern Oil & Gas Annual Report 2013*, May 2014.
23. ConocoPhillips Canada, *Exploration and Development*; and Sahtu Land and Water Board, *Staff Report: Type A Land Use Permit and Type B Water Licence Applications submitted by ConocoPhillips Canada*, 24 June 2014.
24. K'âàlô-Stantec and ConocoPhillips Canada, *The Canol Shale Play: Possible Outcomes of Early Stage Unconventional Resource Exploration*, Discussion Paper, May 2013.
25. Expert Panel (2014), pp. 23–34. For details on Quebec in particular, see Bureau d'audiences publiques sur l'environnement [BAPE], *Les enjeux liés à l'exploration et l'exploitation du gaz de schiste dans le shale d'Utica des basses-terres du Saint-Laurent – Rapport d'enquête et d'audience publique*, Report 307, November 2014.

26. The Council of Canadian Academies (CCA) is an independent non-profit organization that supports authoritative and evidence-based expert assessments to inform the development of Canadian public policy. Environment Canada asked the CCA to "assemble an expert panel to assess the state of knowledge about the impacts of shale gas exploration, extraction and development in Canada." See Expert Panel (2014), pp. iii and vii.

27. Nunavut does not have jurisdiction over land and natural resources like other territories and provinces, but devolution negotiations are ongoing. See Aboriginal Affairs and Northern Development Canada, *Nunavut Devolution*.

28. Expert Panel (2014), p. 88.

29. Ibid.

30. Comité de l'évaluation environnementale stratégique sur le gaz de schiste [EES], *Rapport synthèse: Évaluation environnementale stratégique sur le gaz de schiste*, January 2014, p. 95.

31. CBU (2014), p. 177.

32. Ibid.; and Karen Campbell and Matt Horne, *Shale Gas in British Columbia: Risks to B.C.'s water resources*, The Pembina Institute, September 2011, p. 16.

33. Expert Panel (2014), p. 89–90.

34. CBU (2014), p. 176.

35. Expert Panel (2014), p. 90; and Campbell and Horne (2011), p. 16.

36. Casey G. Vander Ploeg, "Water Management & Allocation in Canada," No. 4 in the *Water Pricing: Seizing a Public Policy Dilemma by the Horns* series, Canada West Foundation, September 2011. Unlike the provinces and the other territories, Nunavut's water regime is established under federal law. (*Nunavut Waters and Nunavut Surface Rights Tribunal Act*, S.C. 2002, c. 10.)

37. Alberta Energy Regulator [AER], *Directive 059: Well Drilling and Completion Data Filing Requirements*, 19 December 2012.

38. New Brunswick, *Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick: Rules for Industry*, 15 February 2013.

39. EES (2014), p. 112.

40. CBU (2014), p. 173.

41. R. D. Vidic et al., "Impact of Shale Gas Development on Regional Water Quality," *Science*, Vol. 340, No. 6134, 17 May 2013.

42. CBU (2014), p. 136.

43. Expert Panel (2014), pp. 44 and 130.

44. Richard J. Davies et al., "Hydraulic fractures: How far can they go?," *Marine and Petroleum Geology*, April 2012.

45. Expert Panel (2014), p. 62. According to the CCA, there has never been a comprehensive study to determine the depth of the bottom of the fresh groundwater zone, which varies between regions.

46. EES (2014), p. 112.

47. A study from the United Kingdom estimates that the likelihood of stimulated hydraulic fractures extending more than 350 metres is less than 1%. See Durham Energy Institute, "Fracking and aquifers: how far up can a frack go?," *DEI Briefing Note No. 902*, Durham University, July 2013.

48. The Royal Society and the Royal Academy of Engineering, *Shale gas extraction in the UK: a review of hydraulic fracturing*, June 2012, p. 37.
49. Expert Panel (2014), p. 79.
50. EES (2014), p. 112.
51. Expert Panel (2014), p. 56.
52. Robert B. Jackson et al., "The Environmental Costs and Benefits of Fracking," *Annual Review of Environment and Resources*, Vol. 39, 2014, p. 338.
53. Summarized from Expert Panel (2014), pp. 55–56.
54. Ibid., pp. 57.
55. Ibid., p. 56.
56. Jackson et al. (2014), p. 338–339; and Expert Panel (2014), p. 58.
57. CBU (2014), p. 202.
58. Ibid.
59. Expert Panel (2014), pp. 80 and 82.
60. Ibid., p. 59.
61. CBU (2014), p. 194.
62. Expert Panel (2014), p. 59.
63. BC Oil and Gas Commission, *Well Permit Application Manual, Version 1.34*, February 2015, pp. 52–53.
64. New Brunswick (February 2013), p. 22.
65. Requirements applicable in Nunavut were adopted at the federal level. See *Canada Oil and Gas Drilling and Production Regulations*, SOR/2009-315.
66. See, for example, BC Oil and Gas Commission, *Well Completion, Maintenance and Abandonment Guideline, Version 1.16*, April 2015; AER, *Directive 008: Surface Casing Depth Requirements*, 9 December 2013; *Directive 009: Casing Cementing Minimum Requirements*, July 1990; and *Directive 044: Requirements for Surveillance, Sampling, and Analysis of Water Production in Hydrocarbon Wells Completed Above the Base of Groundwater Protection*, 14 July 2011. See also Northwest Territories, *Oil and Gas Drilling and Production Regulations*, R-027-2014.
67. AER, *Directive 083: Hydraulic Fracturing – Subsurface Integrity*, 21 May 2013.
68. CBU (2014), p. 178.
69. Ibid., p. 179.
70. United States Environmental Protection Agency [EPA], *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report*, December 2012, p. 16.
71. CESD (2012), p. 26.
72. Expert Panel (2014), p. 49.
73. Ibid. Based on a scenario of 10 wells on the same pad all undergoing the same treatment, which would require 5,000 cubic metres of chemicals.
74. Ibid., p. 77.
75. Ibid.
76. CESD (2012), p. 21.

77. Expert Panel (2014), pp. 49–50.

78. EPA (2012), p. 18.

79. Expert Panel (2014), p. 93.

80. Ibid.,

81. Ibid., p. 94; CBU (2014), p. 185; and EES (2014), p. 118.

82. CBU (2014), p. 185.

83. Expert Panel (2014), p. 94.

84. Ibid., p. 95.

85. Ibid.

86. For example, see CESD, "Part II – Update on Government Responses to Petitions on Hydraulic Fracturing," in "Chapter 5: Environmental Petitions," *Report of the Commissioner of the Environment and Sustainable Development*, Fall 2012.

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88. *Drilling and Production Regulation*, B.C. Reg. 282/2010, s. 37.

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91. See, for example, AER, *Directive 050: Drilling Waste Management*, 2 May 2012; *Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements*, March 1994; *Directive 055: Storage Requirements for the Upstream Petroleum Industry*, December 2001; and *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry*, 1 February 2006. For British Columbia, see Oil and Gas Commission, "Storage of Fluid Returns from Hydraulic Fracturing Operations," Information Letter # OGC 09-07, 12 March 2009; and *Water Service Wells Summary Information*, Version 2.1, February 2015.

92. Expert Panel (2014), p. xiv.

93. Ibid., p. 100; and Investor Environmental Health Network, *Shale gas exploration and production: Key issues and responsible business practices*, March 2013.

94. Expert Panel (2014), p. 100.

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97. Legislative Assembly of Ontario, *Bill 9: An Act to amend the Environmental Protection Act to require the cessation of coal use to generate electricity at generation facilities*, 2014.

98. Environment Canada, *Coal-Fired Electricity Generation Regulations – Overview*.

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100. Alberta Environment and Sustainable Resource Development, *Greenhouse Gas Reduction Program*.

101. British Columbia Ministry of Finance, "Overview of the revenue-neutral carbon tax," *Carbon Tax*.

102. EPA, *Overview of Greenhouse Gases: Methane Emissions*.

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105. Expert Panel (2014), p. 112.
106. Ibid., p. 104.
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110. Fred Krupp, "Don't Just Drill, Baby – Drill Carefully," *Foreign Affairs*, Vol. 93, No. 3, May 2014, pp. 15–20.
111. Expert Panel (2014), p. 107.
112. James Bradbury et al., *Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems*, World Resources Institute Working Paper, April 2013, p. 6; and Krupp (2014).
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117. Environment Canada, "*Heavy-duty Vehicle and Engine Greenhouse Gas Emission Regulations* (SOR/2013–24)," *Current Regulation*.
118. Environment Canada, "*Renewable Fuels Regulations* (SOR/2010–189)," *Current Regulation*.
119. Annie Webb, *Canadian federal and provincial biofuels mandates*, Réseau BioFuelNet Canada, 26 September 2013.
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122. Environment Canada, "*On-Road Vehicle and Engine Emission Regulations* (SOR/2003-2)," *Current Regulation*.
123. Canadian Council of Ministers of the Environment, "Canadian Ambient Air Quality Standards (CAAQS)," *Current Priorities*.
124. AER, *Are there Other Impacts?*
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127. Ibid., p. 41.

128. Supporting infrastructure may include, for example, gravel pits, staging areas, supply yards, compressor stations, water storage facilities and utility corridors for water and gas pipelines or electrical lines.

129. Expert Panel (2014), p. 122.

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131. Expert Panel (2014), p. 123.

132. Ibid., p. 119.

133. Ibid., p. 205.

134. For example, for Alberta, see Environment and Sustainable Resource Development, *Your land. Your plan. Your future*. An overview of British Columbia's land-use planning is provided in CCA (2014), pp. 206–207.

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136. BC Oil and Gas Commission, *Area-based Analysis: Overview*, April 2013, p. 3.

137. Energy and Mines Ministers' Conference, *Responsible Shale Development: Enhancing the Knowledge Base on Shale Oil and Gas in Canada*, August 2013, p. 32.

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156. BC Oil and Gas Commission, *Investigation of Observed Seismicity in the Montney Trend*, December 2014.
157. Jackson et al. (2014), p. 345.
158. Expert Panel (2014), p. 132.
159. See, for example, AER (December 2012), Appendix 3, "Minimum Data Submission Requirements for Daily Record of Operations."
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161. Ibid.; and Energy and Mines Ministers' Conference (2013), p. 31.