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How Robust is the Governance System of British Columbia for Regulating the Environmental Aspects of Shale Gas Development?
by S. Elfving

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Dr. P. Andrews-Speed
Energy Studies Institute,
National University of Singapore
View profile

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How robust is the governance system of British Columbia for regulating the environmental aspects of shale gas development?

Sanna Elfving, PhD Researcher, University of Surrey.

Abstract

This paper focuses on the robustness of the regulatory system of British Columbia (BC) from the environmental point of view. It argues that the enforcement of existing regulations is effective due to the active monitoring of compliance by the provincial oil and gas regulator. The regulator has a key role in promoting transparency, public participation and safety and sustainability of shale gas operations. The paper argues that although certain elements in the provincial legislative framework are covered by non-binding guidelines, rather than legislation, the regulator has responded to many of the concerns raised by the public over the shale gas development in BC, including impacts on regional air quality, fresh water contamination and access to water, deforestation, biodiversity and induced seismicity. The regulator has also recognized several key issues, such as baseline water monitoring as an issue requiring further research. This paper concludes that BC has one of the most robust regulatory systems in North America for regulating hydraulic fracturing.

I. INTRODUCTION

Due to the vast reserves of natural gas now recoverable through unconventional methods, Canada has followed the United States' (US) lead and veered in the direction of maximizing its natural gas production through hydraulic fracturing.[1] Whilst a considerable amount of literature exists on the impacts of shale gas production on groundwater resources, particularly in the US,[2] less has been written about the regulation of unconventional gas production in Canada. This paper tries to close this gap by examining whether Canada's westernmost province, British Columbia (BC) provides a sufficient legal framework for the regulation of shale gas activities whilst protecting the environment. Because much of the province's natural gas deposits are in the early stages of development, the provincial governance systems for regulating shale gas operations are either rather recent or have been subject to substantial amendment in the past few years. Under the Canadian Constitution,[3] the Federal Government regulates oil and gas activities in the northernmost territories (Yukon, Nunavut and Northwest Territories), whereas all other provinces are responsible for regulating onshore oil and gas activities within their jurisdiction.

BC is the second largest producer of natural gas in Canada after Alberta.[4] Total natural gas production in the province in the 2012/13 fiscal year was 1.5 trillion cubic feet.[5] In contrast, one of the most active onshore shale gas fields in the US, the Marcellus Shale region in Pennsylvania, produced the same amount in the first six months of 2013.[6] The majority of shale gas drilling in BC takes place in the remote northeastern part of the province, namely the Montney Basin area and the Horn River Basin. The latter is thought to be one of the largest shale gas deposits in Canada, covering 1.31 million hectares, which is similar to some of the large shale basins in the US.[7]

This paper argues that the enforcement of the existing regulations in BC is effective due to the rigorous reporting requirements imposed on the industry. The provincial oil and gas regulator, the Oil and Gas Commission (the Commission) has the responsibility for overseeing oil and gas operations in the province, including promulgating regulations, ensuring compliance with regulations and providing transparent and timely information to the public, including the content of fracturing fluids, statistics on industry's water use and public safety. Although there are certain elements in the provincial legislative framework which are

[1] See eg Elizabeth Burleson, "Climate change and natural gas dynamic governance" (2013) 63(4) Case Western Reserve Law Review 1246 <http://law.case.edu/student_life/journals/law_review> accessed 21 October 2013.

[2] See e.g. Stephen G Osborn and others, "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing" (2011) 108(20) Proceedings of the National Academy of Sciences 8172; Dave Healy, "Hydraulic fracturing or 'fracking': A short summary of current knowledge and potential environmental impacts" A Small Scale Study for the Environmental Protection Agency (Ireland) under the Science, Technology, Research & Innovation for the Environment (STRIVE) Programme 2007–2013 version 0.81 (July 2012) 9 <http://www.epa.ie/pubs/reports/research/sss/UniAberdeen_FrackingReport.pdf> accessed 20 October 2013.

[3] *Constitution Act*, 1867, 30 & 31 Victoria, c 3 (UK), 92A(1).

[4] National Energy Board, "Marketable Natural Gas Production in Canada" (2013) <http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/mrktblntrlgsprdctn/mrktblntrlgsprdctn-eng.html> accessed 15 April 2014.

[5] See BC Oil and Gas Commission, "Oil and gas land use in northeast British Columbia" (August 2013) 6.

[6] WESA Pittsburgh's NPR News Station, "Marcellus Gas Production Rising Fast in PA, West Virginia" *The Associated Press* (15 August 2013) <http://wesa.fm/post/marcellus-gas-production-rising-fast-pa-west-virginia> accessed 30 October 2013.

[7] C Adams, "Summary of shale gas activity in Northeast British Columbia 2012" in *Oil and Gas Reports 2013* (British Columbia Ministry of Natural Gas Development 2013) 4.

covered by non-binding guidelines rather than legislation, the Commission has responded to many of the concerns raised over the shale gas development in BC by requiring operators, *inter alia*, to minimize adverse impacts of flaring[8] and venting[9] on regional air quality, requiring permits for all surface water withdrawals and by addressing deforestation and associated impacts biodiversity in legislation. The Commission has also recognized several key elements of a robust governance system, such as baseline water monitoring, as an issue requiring further research. Therefore, it appears that in general, the provincial legal framework is rather robust, even though some gaps exist. Due to effective monitoring systems, shale gas operators have kept the Commission well informed of any incidents where the safety of public or the quality of the environment are at risk and in general large scale environmental accidents have been avoided.[10] Although a number of incidents have taken place, including one more serious[11] gas leak near Pouce Coupe, northeastern BC, in 2009 when approximately 30,000 cubic meters of natural gas containing approximately 6,200 parts per million of hydrogen sulfide (H2S) was released into the atmosphere,[12] major threats to public safety and the environment have been avoided.[13] Significantly, there are report incidents of surface water or groundwater contamination as a result of shale gas operations in BC.[14]

This paper is organized in the following way. The first Part discusses briefly the controversies surrounding shale gas development in BC and North America in general. Part Two assesses the legal regime in BC, including regulation of flaring and venting; drilling and underground injection; correct handling and disposal of fracturing fluids; and regulation of surface water and groundwater. Part Three addresses the gaps in the current regulatory framework as well as the recent developments to address these issues.

1.1. What is shale gas and what is so controversial about it?

Shale gas is trapped in compressed fine-grained sedimentary rock formations.[15] The shale formations in northeast BC consist of deposits of mud, silt, clay and organic matter. Because they are relatively impermeable they must be fractured to enable the extraction of natural gas.[16] To drill a shale gas well, operators first drill down vertically to the depth of 1.5 km or

8 Controlled burning of gas.

9 Remedial technique used to remove liquid build-up and restore well productivity.

10 BC Oil and Gas Commission, "Safety Advisories" <http://www.bcogc.ca/publications/safety-advisories> accessed 2 May 2014.

11 A gas leak is considered to be serious, *inter alia*, if hydrogen sulphide (H2S) is present in the gas or constitutes a fire, public safety, or environmental hazard. *Drilling and Production Regulation*, BC Reg 282/2010, s 41.

12 BC Oil and Gas Commission, "Failure Investigation Report: Final report on the Nov. 22, 2009 Failure of Piping at Encana Swan Wellsite A5-7-77-14 L W6M" (November 2010) 5 <http://www.bcogc.ca/node/5935/download> accessed 2 May 2014.

13 The incident at EnCana Swan well site resulted in a total of 18 residents being evacuated from the emergency planning zone.

14 According to Fort Nelson First Nation, members of the First Nation are fearful of eating fish and game harvested from their traditional territory. See Fort Nelson First Nation, "A Water Sustainability Act for B.C. Legislative Proposal: Submissions of Fort Nelson First Nation" (15 November 2013) 2-3 <http://engage.gov.bc.ca/watersustainabilityact/files/2013/11/Fort-Nelson-First-Nation.pdf> accessed 13 May 2014.

15 Leonie Reins, "The shale gas extraction process and its impacts on water resources" (2012) 20(3) RECIEL 300 DOI: 10.1111/j.1467-9388.2012.00733.x.

16 Mark Broomfield and Brian Donovan, *Monitoring and control of fugitive methane from unconventional gas operations* (United Kingdom Environment Agency 2012) 6.

more until they reach a target shale formation.[17] Within the formation, operators then drill horizontally or at an angle to the vertical as much as 3 km to create a lateral or angled well through the shale rock.[18] Once drilling is complete, the well bore is lined with a steel pipe and cement is subsequently pumped around the outside to lock the pipe in place and prevent fluid transfer.[19] Once the cement has hardened, shaped charges can be pushed down the pipe with the aim of cutting holes in the pipework and cement layer at appropriate locations.

The hydraulic fracturing process itself has two main stages: injection and flowback. During injection, a carrier fluid[20] (typically water) and a proppant agent (typically sand) is forced into the well at a high pressure in order to induce fractures in the reservoir rock.[21] The pressure forces the mixture of fluid and proppant into the fractures and holds them open until the pressure is released.[22] Following the release of pressure, some of the initially injected carrier fluid flows back through the well to the surface over the course of three to ten days[23] during which the well begins to produce gas.[24] Flowback water typically contains high levels of chemicals, toxic substances existing naturally in the shale,[25] heavy metals, organic compounds and low levels of naturally occurring radioactive materials.[26] Several hundred different chemicals have been identified in fracturing fluids and wastewater, including methanol, naphthalene, xylene, acetic acid, and ammonia.[27] Although many of these chemicals are generally harmless, some may be toxic and carcinogenic.[28] The fluid brought to the surface during the drilling process from the shale formation is also called "produced water".[29] It consists of a mixture of the flowback water and highly concentrated subterranean

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[17] ibid 9. See also Erik Kiviat, "Risks to biodiversity from hydraulic fracturing for natural gas in the Marcellus and Utica shales" (2013) 1286 Annals of the New York Academy of Sciences 1 DOI: 10.1111/nyas.12146.

[18] Broomfield and Donovan (n 16) 9. Elizabeth Johnson and Laura Johnson, "Hydraulic fracture water usage in northeast British Columbia: locations, volumes and trends" in Geoscience Reports (British Columbia Ministry of Energy and Mines 2012) 59.

[19] Broomfield and Donovan (n 16) 6.

[20] In BC, the most common carrier fluid is water, although nitrogen, propane, and diesel have also been used. See Paul Precht and Don Dempster, "Jurisdictional review of hydraulic fracturing regulation: Report for Nova Scotia Hydraulic Fracturing Review Committee Nova Scotia Department of Energy and Nova Scotia Environment" (27 March 2012) Table A-4.

[21] The range of fluid pressures used in hydraulic fracturing is typically 10,000–15,000 psi (700–1000 bar). In contrast, pressure in a conventional well is less than 10,000 psi (700 bar). See e.g. Broomfield and Donovan (n 16) 11.

[22] ibid 6. See also Precht and Dempster (n 20).

[23] See e.g. John A Veil, "Water management technologies used by Marcellus shale gas producers" (American Petroleum Institute 2010); Broomfield and Donovan (n 16) para 2.3.3. The comparable completion time for a conventional well is much shorter.

[24] According to different estimates, between 15 and 80% of the injected carrier fluid flows back on the surface.

[25] E.g. sodium, chloride, bromide, arsenic, and barium.

[26] See e.g. Veil (n 23); Kiviat (n 17); Margaret A Rafferty and Elena Limonik, "Is shale gas drilling an energy solution or public health crisis?" (2013) 30(5) Public Health Nursing 454 DOI: 10.1111/phn.12036;

[27] Estimates vary between 350 and 600. See e.g. Kiviat (n 17); US Environmental Protection Agency, "Study of hydraulic fracturing and its potential impact on drinking water resources: Progress report" (December 2012) Appendix A (EPA Progress Report) <http://www2.epa.gov/sites/production/files/documents/hf-report20121214.pdf> accessed 19 October 2013; Ruth McDermott-Levy, Nina Kaktins and Barbara Sattler, "Fracking, the environment, and health" (2013) 113(6) American Journal of Nursing 45 DOI: 10.1097/01.NAJ.0000431272.83277.f4; Qiang Wanga and others, "Natural gas from shale formation: The evolution, evidences and challenges of shale gas revolution in United States" (2014) 30 Renewable and Sustainable Energy Reviews 1.

[28] McDermott-Levy, Kaktins and Sattler (n 27).

[29] See BC Oil and Gas Commission, "Oil and gas water use in British Columbia" (August 2010) 7, 11 <http://www.bcogc.ca/document.aspx?documentID=856&type=.pdf> accessed 19 October 2013.

saltwater,[30] which is extracted along with the targeted gas resource. During flowback both gas and liquids are collected.[31] Gas is then separated from liquids and routed to the pipeline for sale.[32]

Concerns raised over the shale gas development in BC include impacts on groundwater and surface water and the aquatic ecosystems; regional air quality; constant, elevated noise levels; heavy truck traffic; induced seismicity;[33] deforestation; forest fragmentation;[34] and a threat to biodiversity and a negative impact on animals, such as boreal caribou.[35] Another controversial issue relating to hydraulic fracturing is its impact on the Canadian economy. According to the Canadian Energy Research Institute, in 2010 approximately 50,000 jobs were created in Canada as a result of shale gas operations in BC.[36] The Institute predicts that by 2035 shale gas operations will create more than 160,000 jobs.[37] Although studies on the local economic impact may be important for the public acceptance of shale gas development, studies are frequently contested, *inter alia*, due to the use of numerous assumptions about the profitability of operations and their inability to evaluate the implications of rapid and substantial changes in the economy.[38] In fact, despite growth, BC's natural gas industry has been argued to face difficulties due to the oversupply of gas on its traditional export market in the US, which has led some major producers in the province to curtail their production.[39] The problems have been further exacerbated by weak overall economy, warm winters and limited domestic potential.[40] Therefore, it has been acknowledged that the growth in the province's natural gas industry will be difficult to sustain without the creation of new export markets.[41] This raises the question whether the establishment of shale gas operations is driven by political interests in job creation and thriving local economies at the expense of careful attention to environmental concerns.

Additionally, although large-scale operations are expected to increase wealth and income of a number of individuals and communities during the parts of the development cycle,[42] most frequently the prevailing business model of resource extraction is the one in which operations

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[30] This is because shale formations were originally laid down in marine environments. See Broomfield and Donovan (n 16) 8.
[31] Liquid is often stored in lined earthen ponds, where it stays until the sediments settle to the bottom.
[32] See e.g. Healy (n 2).
[33] ibid
[34] See e.g. Kiviat (n 17).
[35] Caribou are highly sensitive to industrial activity. See e.g. Forest Practices Board, "A case study of the Kiskatinaw River watershed: an appendix to cumulative effects: from assessment towards management" (2011) 9 and Appendix 2, <http://www.fpb.gov.bc.ca/SR39_CEA_Case_Study_for_the_Kiskatinaw_River_Watershed.pdf> accessed 21 October 2013.
[36] Canadian Energy Research Institute, "Economic impacts of drilling, completing, and operation of gas wells in Western Canada (2010-2035)" (June 2011) 15.
[37] ibid
[38] See e.g. David Kay, "The economic impact of Marcellus shale gas drilling: What have we learned? What are the limitations?" Working Paper Series (Cornell University 2011) 5-6.
[39] Fraser Basin Council, "Identifying health concerns relating to oil & gas development in northeastern BC: human health risk assessment" Phase 1 report (30 March 2012).
[40] Only 16% of natural gas produced in BC is consumed provincially. 84% is exported to the US or used elsewhere in Canada. Ministry of Energy and Mines, "British Columbia's Natural Gas Strategy: Fuelling B.C.'s Economy for the Next Decade and Beyond" (2012) 4 <http://www.gov.bc.ca/ener/popt/down/natural_gas_strategy.pdf> accessed 19 October 2013.
[41] Fraser Basin Council (n 39).
[42] Fraser Basin Council (n 39).

are under the control of outside corporations.[43] Therefore, benefits for the surrounding communities are typically modest in economic value in comparison to the profits gained by the corporations.[44] Moreover, hydraulic fracturing and associated operations are likely to bring new risks, and most unavoidably, significant change in the quality of life and sense of well-being for these communities.[45] Furthermore, property values may decrease due to the proximity of drilling sites.[46]

Although this paper focuses primarily on the robustness of the regulatory system from the environmental point of view, it is noteworthy that until rather recently most shale gas production in North America has occurred in areas where population density is relatively low.[47] Therefore social opposition has not affected the development of the industry in these areas.[48] As the development continues to expand into more densely populated areas, there is an increased likelihood of conflict with other land users.[49] In BC, the rights of landowners and the general public to participate in decisions affecting them are recognized under section 22(3) of the *Oil and Gas Activities Act*, 2008.[50] Additionally, Northeastern BC, where most of the province's shale gas production occurs, is home to at least five Treaty 8 First Nations[51] whose reserves are located near shale gas extraction zones. Because First Nations' rights are specifically protected by the Canadian Constitution[52] their rights must be taken into account in order to mitigate any adverse impacts on these communities.[53]

Accordingly, at minimum the provincial decision-making concerning shale gas development should be inclusive, transparent and representative in order to balance various competing interests, including the interests of the industry and social and environmental concerns raised by the public.[54] It appears that the Commission is aware of such needs and according to it, regulatory trends are influenced by the interests of First Nations, landowners and the general public, particularly with respect to protecting the environment.[55]

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[43] United Nations Human Rights Council, (Sub-Commission), "Report of the Special Rapporteur on the rights of indigenous peoples, James Anaya, Extractive industries and indigenous peoples" (2013) UN Doc A/HRC/24/41, 4.

[44] ibid. At best, people living near fracturing sites may be offered benefits in the form of jobs or community development projects.

[45] Kay (n 38) 5-6; McDermott-Levy, Kaktins and Sattler (n 27).

[46] McDermott-Levy, Kaktins and Sattler (n 27).

[47] e.g. the Barnett shale gas field in northern Texas consists of approximately 8,000 wells spread over an area, which is comparable to the combined area of the Belgium, the Netherlands and Luxembourg. However, the population density is in the Barnett shale gas field is only 38 inhabitants per km2. See e.g. Boyan Kavalov and Nathan Pelletier, *Shale gas for Europe: Main environmental and social considerations* (Publications Office of the European Union 2012) 33.

[48] ibid

[49] ibid. See also Renee Lewis, "Shale gas company loses bid to halt Canada protests" *Aljazeera America* (21 October 2013) <http://america.aljazeera.com/articles/2013/10/21/shale-gas-companylosesbidforinjunctiontohaltcanadaprotests.html> accessed 31 October 2013.

[50] SBC 2008, C 36.

[51] First Nations are descendants of the North American Indians, who signed Treaty No 8 with the European settler nations in 1899 covering an area comprising parts of Alberta, British Columbia, Saskatchewan and the Northwest Territories.

[52] *Constitution Act*, 1982, s 35(1), being Schedule B to the Canada Act 1982 (UK), 1982 c 11: "The existing aboriginal and treaty rights of the aboriginal peoples of Canada are hereby recognized and affirmed."

[53] It has been argued that shale gas development may have an adverse impact on human health and result in a conflict between economic benefits and social costs. Thomas A Kerns, "A human rights assessment of hydraulic fracturing for natural gas" Earthworks' Oil and Gas Accountability Project (12 December 2011).

[54] See also Burleson (n 1).

[55] BC Oil and Gas Commission, "2014/15-2016/17 Service Plan" 15 <https://www.bcogc.ca/node/11169/download> accessed 15 April 2014.

Additionally, the United Nations General Assembly has identified a link between human rights and environmental damage caused by hydraulic fracturing. The General Assembly recognizes that environmental damage caused by hydraulic fracturing poses "a new threat to human rights".[56] The Human Rights Council Resolution 16/11 "On human rights and the environment" states that "environmental damage can have negative implications, both direct and indirect, for the effective enjoyment of human rights".[57] Therefore, it is highly important that prior to the approval of a shale gas activities permit, operators carry out consultations or provide notices to any parties who may be potentially affected by the proposed development. In BC, permit holders may need to consult or notify, *inter alia*, First Nations, the federal government, landowners, municipal councils and local authorities as per section 4 of the *Consultation and Notification Regulation*, 2010.[58]

The next sections assess the effectiveness of the BC's legislative framework with the view of answering the question whether the shale gas regulation in BC is able to minimize the potential adverse impacts on, *inter alia*, human health, regional air quality and fresh water resources.

II. ASSESSING THE LEGAL REGIME IN BC

The legal framework applicable to shale gas operations in BC is composed of several pieces of provincial legislation (acts, regulations, directives) and guidelines. BC shale gas regulation falls under several pieces of environmental law and conventional energy law. The main legal instruments are the provincial *Oil and Gas Waste Regulation*, 2005;[59] the *Oil and Gas Activities Act*, 2008;[60] the *Drilling and Production Regulation*, 2010;[61] and the *Environmental Protection and Management Regulation*, 2010.[62]

The Commission has responded to many of the concerns raised by the public, *inter alia*, by tightening up the rules relating to surface water withdrawals;[63] by requiring disclosure of chemicals and additives used in hydraulic fracturing; and by conducting an assessment on seismicity.[64] It collates statistics on water use, public safety and compliance with regulations,[65] which are publically available on its website. Monitoring and enforcement of the provincial legislation can be argued to be effective due to the requirement of the operators to report, *inter alia*, their drilling activities, any incidents, ground and surface water use and the content of fracturing fluids to the Commission. Section 8 of the *Drilling and Production*

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56 United Nations General Assembly, Document A/HRC/18/NGO/91, "Hydraulic fracturing for natural gas: A new threat to human Rights" distributed 19 September 2011.
57 United Nations Human Rights Council, Resolution 16/11 "On Human Rights and the Environment" adopted on 24 March 2011.
58 BC Reg 279/2010.
59 BC Reg 254/2005.
60 SBC 2008, C 36.
61 *Drilling and Production Regulation*, BC Reg 282/2010 regulates wells (e.g. permits; spacing; operations; abandonment; and well data), safety, pollution prevention, and production operations. Specially, it includes sections on fracturing operations, hydraulic isolation, fracturing fluids records, produced water, and water source wells.
62 BC Reg 200/2010.
63 Directive 2011-02 Changes in Section 8 short term water use approvals (2 March 2011).
64 Precht and Dempster (n 20) Table A-8.
65 BC Oil and Gas Commission, "Enforcement Action Summary" <http://www.bcogc.ca/reports/enforcement-action-summary> accessed 22 April 2014.

Regulation, 2010[66] requires operators to report the Commission online at every stage of operations, including the beginning of construction and drilling; releasing of a rig; any times when drilling is completed or temporarily suspended; and resuming of drilling operations after a temporary suspension. The notice must be sent within 24 hours of the action being taken, apart from the beginning of construction when the notice must be made at least 48 hours before.[67] There is also a weekly update notification requirement (known as the Wednesday morning update).[68]

Section 17 of the *Oil and Gas Activities Act General Regulation*, 2010[69] gives the Commission the power to make public all records or reports submitted to it under section 37 of the *Drilling and Production Regulation*, 2010,[70] which requires shale gas operators to keep records of, *inter alia*, fluid ingredients and their purpose; ingredient concentration in any additives and in fracturing fluids; and the total volume of water injected underground with the fluid ingredients.[71] The problem of deforestation and its impacts on biodiversity have been addressed by the section 6 of the *Environmental Protection and Management Regulation*, 2010,[72] which stipulates that oil and gas activities must take place outside of wildlife habitats and the wildlife tree retention area. Additionally, oil and gas activities "must be carried out at a time and in a manner that does not result in physical disturbance to high priority wildlife or their habitat, including disturbance during sensitive seasons and critical life-cycle stages".[73] Furthermore, oil and gas activities cannot damage or render ineffective a wildlife habitat feature.[74] In 2010 the provincial government also established "resource review areas" in the north of the province where no oil and gas activities are allowed for five years in order to protect boreal caribou populations.[75] The establishment of these areas is significant because the government recognizes shale gas development may not be suitable in certain parts of the province either because of insufficient environmental information exists or because the land use conflicts resulting from the development may lead to destruction of the habitat of an endangered species or culturally significant land.[76]

In 2013, the Commission issued a number of Orders for a failure to comply with section 49(1)(b) of the *Oil and Gas Activities Act*, 2008[77] associated regulations, permits or authorizations. Typically, Orders were issued in order to mitigate a risk to public safety, to protect the environment, or to promote the conservation of petroleum and natural gas resources.[78] In the last quarter of 2013, many of the Orders concerned a failure to install seismology equipment or to test and remediate soil within the operations area. Additionally, a small number of shale gas operators were fined for the failure to keep or produce the

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[66] BC Reg 282/2010.
[67] *Drilling and Production Regulation*, BC Reg 282/2010, s 8.
[68] See BC Oil and Gas Commission, "Wells drilling guideline" Version 1.6 (September 2013).
[69] BC Reg 274/2010.
[70] BC Reg 282/2010.
[71] The information is publically available at www.fracfocus.ca.
[72] BC Reg 200/2010.
[73] *Environmental Protection and Management Regulation*, BC Reg 200/2010, s 6.
[74] ibid
[75] Steven F Wilson, Chris Pasztor and Sara Dickinson, "Projected Boreal Caribou Habitat Conditions and Range Populations for Future Management Options in British Columbia" (22 April 2010).
[76] Council of Canadian Academics, *Environmental Impacts of Shale Gas Extraction in Canada: The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction* (Council of Canadian Academies 2014) 207.
[77] SBC 2008, C 36.
[78] Enforcement Action Summary (n 65).

Commission with water records under section 22 of the provincial *Water Act*, 1996[79] or for exceeding air emission standards under sections 6 and 120 of the *Environmental Management Act*, 2003.[80] The rules concerning these Orders stipulate that if a recipient of an Order does not comply by a specified date, under section 50 of the *Oil and Gas Activities Act*, 2008 a Commission official may take specific actions respecting the initial Order and, upon completion, require the company pay all direct and indirect costs incurred by the Commission.

Alternatively, the Commission may, by Order, restrict or prohibit a company from carrying out an action referred to in the initial Order. Under section 88 of the *Oil and Gas Activities Act*, 2008 the Commission may apply to the provincial Supreme Court for an Order directing either the company or its directors and officers to comply with, or stop violating, the initial Order issued under section 49(1)(b). The Commission's quarterly enforcement action summaries indicate that in most cases compliance was achieved after the issuance of the initial Order.[81] Therefore, it appears that the monitoring and reporting requirements have strengthened compliance with the provincial regulations. Ultimately, policies which promote transparency, public participation, safety of shale gas operations and sustainable use of natural resources, including fresh water resources, can mitigate public concerns over negative impacts of hydraulic fracturing on the environment.

2.1. Regulation of flaring and venting

Hydraulic fracturing operations have been argued to have an adverse impact on air quality due to significant fugitive methane emissions[82] and direct carbon dioxide (CO2) emissions into the atmosphere.[83] There are some views that fugitive emissions could entirely counter the benefits of increased natural gas use due to their climate destabilizing consequences.[84] While there is a broad international consensus that urgent energy policy shifts are required to mitigate greenhouse gas emissions, insufficient information exists to measure the greenhouse gas footprint over the entire life-cycle of natural gas fuels.[85] Therefore, strict regulation is seen as necessary in order to minimize all emissions of methane and other compounds and prohibit all unnecessary flaring and venting in order to protect the atmosphere and human health.[86]

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[79] Enforcement Action Summary (n 65).
[80] SBC 2003, C 53.
[81] See Enforcement Action Summary (n 65).
[82] Fugitive emissions are unintentional escaping of methane. It is also thought that fugitive emissions from compressors, which are used to assist in natural gas extraction, may be significant and require careful attention from operators and regulators. See Broomfield and Donovan (n 16) paras 2.3.3 and 4.7.
[83] Burleson (n 1); Ivan Pearson and others, *Unconventional gas: Potential energy market impacts in the European Union. A report by the Energy Security Unit of the European Commission's Joint Research Centre* (Publications Office of the European Union, 2012) 143.
[84] Burleson (n 1); Kavalov and Pelletier (n 47) 27.
[85] See e.g. Robert W Howarth, Renee Santoro and Anthony Ingraffea, "Methane and the greenhouse-gas footprint of natural gas from shale formations" (2011) 106(4) Climatic Change 679. The greenhouse gas footprint of natural gas development includes direct emissions from end-use consumption and indirect emissions from fossil fuels used to extract, develop, and transport the gas.
[86] See e.g. Healy (n 2) 21; Burleson (n 1).

Although BC currently authorizes air discharges relating to shale gas operations under section 4 of the provincial *Oil and Gas Waste Regulation,* 2005,[87] the provincial government has expressed its commitment to reduce greenhouse gas emissions. The government's commitments and initiatives under the provincial Energy Plan[88] include, *inter alia,* elimination of all "continuous flaring of gas that is not required for safety or environmental purposes and is economical to conserve" by 2016.[89] The commitment to reduce flaring during shale gas operations is reflected in section 42(1) of the *Drilling and Production Regulation*, [90] 2010, which stipulates that both the quantity of gas that is flared or vented and the duration of these activities must be minimized. In line with this the *Oil and Gas Waste Regulations*, 2005 stipulate that natural gas should be conserved instead of flaring and venting, where possible.[91]

According to the "Flaring and Venting Reduction Guideline",[92] methods of conservation include routing shale gas to a pipeline for sales, lease fuel, power generation, pressure maintenance or any other alternative method that may become available.[93] The Guideline aims at ensuring that flaring and incinerating are conducted in a safe and responsible manner and that venting occurs only where conservation or flaring is unfeasible.[94] Additionally, section 41(1) of the *Drilling and Production Regulation*, 2010 stipulates that venting should only be used if flaring is not possible because the gas heating value, volume or flow rate is insufficient to support stable combustion.[95] Therefore, the provincial government's preferred method of collecting methane is conservation, then flaring, whereas venting is the least preferred option.

Additionally, the Commission has expressed its commitment to improve reporting on flaring. Under the "Flaring and Venting Reduction Guideline" operators must, *inter alia*, report all occurrences of flaring to the Commission.[96] Additionally, all monthly flared, incinerated and vented volumes must be reported to the Ministry of Finance for the tax purposes.[97] Should any significant deficiencies in the flared volumes be identified the Commission may order an installation of a flare meter at a facility.[98]

However, certain aspects of the regulatory system may hamper the commitments to reduce greenhouse gas emissions of the oil and gas industry. The Energy Plan targets have been criticized on the grounds that increased production of shale gas and the proposed construction of liquefied natural gas export terminals in Kilimat, BC present a tremendous challenge to the reduction targets because shale gas operations are emissions-intensive and the production of

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[87] BC Reg 254/2005. Additionally, s 6 (1)(d)(ii) stipulates that a facility used for well testing is authorized to discharge air contaminants if "the natural gas combusted is discharged to the air through a flare stack that has a minimum height of 12 meters or combusted in an incinerator".

[88] See BC Ministry of Energy, Mines and Petroleum Resources, "The BC Energy Plan: A vision for clean energy leadership" (2007) paras 36-38 <http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan_Oil_and_Gas.pdf> 19 October 2013.

[89] Its interim goal was to reduce routine flaring by 50% by 2011. This target was met in 2010. See BC Oil and Gas Commission, "2012 Flaring Summary" (2013) 4 (Flaring Summary report) <http://www.bcogc.ca/node/11030/download> accessed 7 April 2014.

[90] BC Reg 282/2010

[91] BC Reg 254/2005, s 4.

[92] BC Oil and Gas Commission, "Flaring and Venting Reduction Guideline" (February 2013) <https://www.bcogc.ca/node/5916/download> 19 October 2013.

[93] ibid 17.

[94] ibid

[95] *Drilling and Production Regulation*, BC Reg 282/2010, s 41(1).

[96] Flaring and Venting Reduction Guideline (n 92) 44.

[97] ibid 39.

[98] ibid 37.

liquefied natural gas is energy-intensive.[99] For instance, flaring from production facilities increased 19% between 2011 and 2012 due to the growth in overall shale gas production.[100] Additionally, operators who obtained their well permits before the entry into force of *Drilling and Production Regulation*, 2010[101] are covered by transitional provisions under the *Oil and Gas Activities Act*, 2008.[102] Therefore, they are authorized to flare gas for the purposes of well clean up and testing,[103] provided that the cumulative quantity of flared gas does not exceed 400,000 m3 or 600,000 m3 depending on whether the well is a development well or an exploratory well.[104] However, well clean-up and testing amount to a large volumes of flared gas.[105] Therefore, commitments to reduce flaring and greenhouse gas emission may seem rather superficial.

In order to encourage emissions reductions in 2008 the provincial government imposed a carbon tax on all emissions resulting from the burning of various fossil fuels.[106] In its opinion the carbon tax is likely to have an impact on greenhouse gas emissions. Emissions from combusting of various fossil fuels are a significant source of greenhouse gas emissions in BC because they currently account for 69% of the total provincial emissions.[107] According to the provincial government, the oil and gas industry pays carbon tax on all combustion of fuels, which are estimated to account 85% of its total emissions.[108] Currently, a fee, 30 Canadian dollars, is levied for every metric ton of carbon dioxide equivalent emissions resulting from the burning of fossil fuels, including flaring.[109] However, questions have been raised whether the tax may have negatively impacted the province’s economic performance when compared to the rest of Canada.[110] Although some believe that the tax has transformed the culture of energy use in BC,[111] others claim that no clear evidence links the tax to significant reductions in provincial greenhouse gas emissions.[112]

It is worth noting that the carbon tax does not address the adverse impacts of venting and fugitive emissions on air quality because they are not subject to the tax.[113] Venting and fugitive emissions nevertheless form an important part of the province’s carbon emissions

[99] Kathryn Harrison, “The Political Economy of British Columbia's Carbon Tax” (2013) OECD Environment Working Papers No 63, 9 <http://dx.doi.org/10.1787/5k3z04gkkhkg-en> accessed 7 April 2014. Plans are underway to build facilities enabling exports of liquefied natural gas to Asia. See e.g. Pearson and others (n 83) 158.

[100] Flaring Summary report (n 89) 6.

[101] BC Reg 282/2010.

[102] SBC 2008, C 36, s 116.

[103] *Drilling and Production Regulation*, BC Reg 282/2010, s 42(4).

[104] ibid

[105] 71.3 million m3 in 2012. See Flaring Summary report (n 89) 6.

[106] BC Ministry of Finance, “Myths and Facts about the Carbon Tax” <http://www.fin.gov.bc.ca/tbs/tp/climate/A6.htm> accessed 7 April 2014.

[107] ibid. The remaining 31% is due to non-energy agriculture and landfills (10%), fugitive emissions (10%), non-combustion industrial process emissions (6%) and net deforestation (5%).

[108] ibid

[109] The tax started at CAD$10 per tonne of carbon dioxide equivalent (CO2e) and rising by CAD$5/tonne CO2e/year to a 2012-2013 value of CAD$30/tonne CO2e. See e.g. Sierra Rayne and Kaya Forest, “British Columbia's carbon tax: Greenhouse gas emission and economic trends since introduction” (2013) Working Paper, 1 <http://vixra.org/pdf/1301.0094v2.pdf> accessed 7 April 2014. See also Chris Mooney, “British Columbia Enacted the Most Significant Carbon Tax in the Western Hemisphere. What Happened Next Is It Worked” *Mother Jones* (26 March 2014) <http://www.motherjones.com/environment/2014/03/british-columbia-carbon-tax-sanity> accessed 7 April 2014.

[110] See e.g. Rayne and Forest (n 109) 5.

[111] See e.g. Mooney (n 109).

[112] See e.g. Rayne and Forest (n 109) 4.

[113] Harrison (n 99) 9.

since they accounted for one quarter of the overall emissions growth in BC between 1990 and 2010.[114] Although operators clearly are under pressure to reduce greenhouse gas emissions due to their impact on regional air quality and global warming,[115] other reasons, both economic and non-economic, exist for the operators to monitor and reduce methane emissions. For instance, methane has implications on public safety,[116] which in turn may have implications on the operators' liability. It can also be argued that the profitability of the shale gas operations can incentivize the operators to monitor and minimize fugitive emissions.[117] Because gas losses potentially reduce the overall profitability of the shale gas operations, there is a clear economic benefit to the operator to minimize fugitive methane emissions during the well construction and production stages.[118]

Another effective measure to reduce emissions is to impose a legal requirement to use reduced emission completions (or green completions),[119] which involve installing portable equipment that is specially designed to control fugitive emissions during flowback when the flow of liquid, sand and gas through the well to the surface is high.[120] The aim of green completions is to make shale gas production more environmentally friendly by capturing gas for use or sale after it has been separated from liquid instead of releasing it to the atmosphere.[121] However, green completions are not currently required by law in BC.

In conclusion, although the provincial government has cut down all routine flaring by half under the BC Energy Plan and has introduced, *inter alia*, the carbon tax to further reduce greenhouse gas emissions, the commitments to achieve the emission reduction targets may not be ambitious enough due to the transitional provisions under the *Oil and Gas Activities Act*, 2008,[122] which enable operators to flare large amounts of natural gas for the purposes of well clean-up and testing.[123] Additionally, flaring from production facilities has, in fact, increased in the past few years due the higher production capacity in the province.[124]

2.1.1. Mitigating impacts of temporary flaring near populated areas

According to the Commission's "Flaring and Venting Reduction Guideline", operators must make reasonable efforts to minimize adverse impacts of temporary flaring near populated areas.[125] Consideration should be given to reducing noise, flaring during daylight hours and

[114] Ben Clark and Dennis Paradine, *British Columbia Greenhouse Gas Inventory Report 2010* (British Columbia Ministry of Environment 2012) <http://www.env.gov.bc.ca/cas/mitigation/ghg_inventory/pdf/pir-2010-full-report.pdf> accessed 7 April 2014.
[115] Broomfield and Donovan (n 16) para 3.1.
[116] Methane can be explosive if present at concentrations within a defined range. Methane could potentially also act as an asphyxiant if present at elevated levels within a confined space.
[117] Broomfield and Donovan (n 16) para 3.1.
[118] ibid. Methane can also leak during transport, storage and distribution. See e.g. McDermott-Levy, Kaktins and Sattler (n 27); Howarth, Santoro and Ingraffea (n 85).
[119] See e.g. Burleson (n 1); Broomfield and Donovan (n 16) para 4.2.
[120] Ohio Environmental Protection Agency, "Exploration, Production and Processing of Oil and Natural Gas from the Marcellus and Utica Shales in Ohio: Understanding the Basics of Gas Flaring" (May 2012) <http://www.epa.state.oh.us/portals/0/General%20pdfs/gas%20flaring.pdf> accessed 22 November 2013.
[121] ibid
[122] SBC 2008, C 36.
[123] Flaring Summary report (n 89) 6.
[124] ibid
[125] Flaring and Venting Reduction Guideline (n 92) 28.

the use of incineration, where appropriate.[126] Before a decision is made to use an incinerator, an operator must consider, *inter alia*, the potential to exceed air quality objectives for sulfur dioxide (SO2)[127] and the potential for black smoke emissions; results of any consultation with the landowner and residents within the consultation radius; history of flaring concerns and activity levels in the area; quantity and duration of flaring; visibility of flare to area residents, communities and major highways; and noise.[128]

According to the "Flaring and Venting Reduction Guideline", operators should comply with the noise limits established in the "British Columbia Noise Control Best Practices Guideline".[129] The Noise Control guideline considers the interests of both nearby residents and the operator, and therefore, it is not a guarantee that residents near a facility will not hear noise from it.[130] However, new facilities must conduct a noise impact assessment in order to ensure that operators consider possible noise impacts before a facility is constructed or in operation.

Operators must also notify all occurrences of flaring, incinerating or venting to the Commission, all residents and administrators of incorporated centers located within the notification radius.[131] However, there is no need to consult. Notification must be given a minimum of 24 hours prior to the commencement of planned flaring events and within 24 hours of any unplanned flaring events.[132] Operators should consult with residents and other entities within the notification radius to develop and implement a mutually acceptable notification process.[133] Additionally, operators must have a fugitive emissions management plan,[134] in accordance with the guideline of the Canadian Association of Petroleum Producers.[135] Although the Flaring and Venting Reduction Guidelines stipulates that operators must make reasonable effort to address the concerns of residents relating to flaring[136] the protection of residents is not enforced by law.

2.1.2. Air quality monitoring

It is noteworthy that all measures relating to air quality monitoring are set by guidelines rather than legislation. The guidelines stipulate that evaluating or monitoring of the impacts

[126] Flaring and Venting Reduction Guideline (n 92) 28.
[127] When natural gas containing hydrogen sulphide (H2S) is combusted, it is converted to sulphur dioxide (SO2). High concentrations can adversely affect the respiratory systems of humans and animals, and can damage vegetation. See e.g. Environment Canada, "Ambient Levels of Sulphur Dioxide" <http://www.ec.gc.ca/indicateurs-indicators/default.asp?lang=en&n=307CCE5B-1> accessed 7 April 2014; A Vago and others, "Removal of hydrogen sulphide from natural gas, a motor vehicle fuel" (2011) 39(2) Hungarian Journal of Industrial Chemistry 283.
[128] Flaring and Venting Reduction Guideline (n 92) 58.
[129] ibid
[130] BC Oil and Gas Commission, "British Columbia Noise Control Best Practices Guideline" (March 2009) paras 1.2.1 and 3.1.
[131] Flaring and Venting Reduction Guideline (n 92) 27. This is variable between 1 and 1,5 km. The exact notification radius depends on the H2S content and the duration or volume of flaring. See ibid Table 6.1
[132] ibid 27.
[133] ibid
[134] ibid
[135] Canadian Association of Petroleum Producers, "Best management practice: Management of fugitive emissions at upstream oil and gas facilities" (January 2007) <http://www.capp.ca/getdoc.aspx?DocId=116116&DT=PDF> accessed 19 October 2013.
[136] Flaring and Venting Reduction Guideline (n 92) 37.

of flaring on air quality is mandatory only if the flared gas has a certain concentration of hydrogen sulfide (H2S). This is because depending on its H2S concentration, natural gas may pose a public safety hazard, if released into the atmosphere.[137] H2S is highly flammable and can cause adverse health effects, including collapse, inability to breathe and death within minutes, if inhaled in high concentrations.[138] Additionally, venting of natural gas containing H2S may result in unacceptable off-site odors.[139] Therefore, the Commission recommends that permit holders eliminate all venting of gas containing H2S.[140] The requirement is further strengthened by legislation since section 41(1) of the *Drilling and Production Regulation*, 2010 stipulates that venting must be conducted in a manner that does not constitute a safety hazard or does not result in off-site odors.[141]

According to the "Flaring and Venting Reduction Guideline", shale gas operators must evaluate impacts of flaring on ambient air quality, if the H2S content in natural gas exceeds 1% by volume.[142] They must also retain information on air dispersion assessments and provide it to the Commission upon request. If the H2S content in natural gas exceeds 5% by volume, operators must submit air dispersion modelling to the Commission in accordance with section 6(1)(d) of the *Oil and Gas Waste Regulation*, 2005.[143] Depending on the results of the dispersion modelling the Commission may, *inter alia*, require air quality monitoring or meteorological monitoring with shutdown criteria. Alternatively, the Commission may impose flow rate, gas composition and flare stack height requirements on operators.[144] If the H2S content of natural gas exceeds the maximum value listed in the operators' permit conditions, operations must be suspended until the Commission has approved their resumption.[145]

In conclusion, although the provincial government aims to reduce nuisance impacts associated with flaring, venting and incineration, including noise and odors in or near populated areas, and improve reporting concerning flaring, air quality monitoring is required only if the flared gas has a specific H2S concentration. Although there is a legislative requirement to minimize duration flaring and venting as well as the quantity of gas flared and vented, these requirements may not be stringent enough to incentivize shale gas operators to minimize the impacts of flaring on surrounding communities because they have no legal rights to be consulted in relation to flaring although their concerns and objections must be taken into account. Whether the fact that flaring is subject to the provincial carbon tax has an impact on the overall reduction of flaring is also unclear. However, it may have an impact on the profitability of shale gas operations and hence incentivize reductions in the long run.

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[137] Flaring and Venting Reduction Guideline (n 92) 69.
[138] A range of other effects on the nervous and cardiovascular system may occur following single or repeated exposures to high concentrations. See Public Health England, Centre for Radiation, Chemical and Environmental Hazards, Toxicology Department, "Hydrogen Sulphide: General Information" (2009) Version 1, 3 <http://www.hpa.org.uk/webc/HPAwebFile/HPAweb_C/1246260029655> accessed 18 October 2013.
[139] Flaring and Venting Reduction Guideline (n 92) 69.
[140] ibid 54.
[141] ibid
[142] ibid 32.
[143] ibid
[144] ibid
[145] ibid 33.

2.2. Regulation of drilling and underground injection

Hydraulic fracturing activities have frequently been linked to groundwater contamination in nearby fresh water aquifers,[146] making groundwater unusable for human consumption for households located near fracking sites.[147] It is worth noting that considerable disagreement exists as to the exact causes of water contamination in this context, even though a link has been identified between the chemicals used in fracturing fluids and groundwater contamination.[148] An on-going study by the US Environment Protection Agency, which investigates the potential impacts to drinking water resources from the chemicals associated with hydraulic fracturing, has been unable to draw any definitive conclusions on the matter, indicating that the current state of knowledge is incomplete.[149] Similarly, a report published in May 2014 by the Council of Canadian Academies was unable to draw definitive conclusions on the exact cause of potential fresh water contamination. The report nevertheless identified well-integrity and the prevention of fluid and gas migration as critical for the protection of the environment.[150] Therefore, a continuing effort to improve well integrity, including cementation of wellbores was identified as absolutely essential.[151]

Since it has been acknowledged that any engineering structure has a certain failure rate, several experts are of the opinion that fresh water contamination may be caused by a variety of factors, including improper cementing of wells and the quality and integrity of borehole casings,[152] pipes or storage tanks.[153] It would appear that if improper cementing and well casing design were the most likely causes,[154] robust well construction requirements would be critical in the minimization of risks associated with fresh water contamination. Critics nevertheless point out that operations may be compromised if well structure is debilitated due to injection of fracturing fluids at extremely high pressures.[155] Therefore, systems to monitor well integrity are also critical.

The provincial well construction requirements include multiple layers of protective steel casing and cement, which are specifically aimed at protecting fresh water aquifers and to

[146] Aquifers are defined as “saturated geologic units that are permeable and yield water in a usable quantity to a well, spring or stream”. See J Berardinucci and K Ronneseth, *Guide to using the BC aquifer classification maps for the protection and management of groundwater* (BC Ministry of Water, Land and Air Protection 2002) 5.
[147] See e.g. Osborn and others (n 2).
[148] See e.g. Kiviat (n 17); Theo Colborn and others, “Natural gas operations from a public health perspective” (2011) 17(5) Human and Ecological Risk Assessment 1039; Sally Entrekin and others, “Rapid expansion of natural gas development poses a threat to surface waters” (2011) 9 Frontiers in Ecology and the Environment 503 http://dx.doi.org/10.1890/110053.
[149] EPA Progress Report (n 27) paras 9.3-9.4. See also R J Davies, “Methane contamination of drinking water caused by hydraulic fracturing remains unproven” (2011) 108 (43) Proceedings of the National Academy of Sciences E871.
[150] Council of Canadian Academics (n 76) 37, 55. According to the expert panel, scientific knowledge in this area is limited due to lack of suitable groundwater monitoring systems. ibid 81.
[151] ibid 37, 55.
[152] e.g. due to inadequate number of casings.
[153] See e.g. ALL Consulting, “The modern practices of hydraulic fracturing: A focus on Canadian resources” (November 2012) 8; Healy (n 2) 10; Christine Coussens and Rose Marie Martinez, *Health Impact Assessment of Shale Gas Extraction: Workshop Summary* (National Academies Press 2014) 69.
[154] See e.g. ALL Consulting (n 153) 8.
[155] See e.g. American Petroleum Institute, “Hydraulic fracturing operations-well construction and integrity Guidelines” Guidance Document (October 2009) 1 <http://www.shalegas.energy.gov/resources/HF1.pdf> accessed 15 October 2013; Paula Barrios, “CAPP’s new guidelines for Canadian shale gas producers: A review of key requirements” Shareholders Association for Research and Education (February 2012); Coussens and Martinez (n 153).

ensure that the gas producing zone is isolated from overlying fresh water formations.[156] Similarly, existing legislation requires pressure-testing on installation and during well operations "as often as necessary".[157] Therefore, the provincial requirements concerning wellbore construction and testing seemingly address the concerns that water contamination from wellbore may impact fresh water aquifers. It has been argued that testing of well casing and cement prior to injection of fracturing of fluids should be mandatory by regulation.[158] Since this is the case for BC, the provincial wellbore construction and integrity verification requirements are specifically tailored to mitigate environmental risks associated with hydraulic fracturing. As such, these requirements should also alleviate public concerns over fresh water contamination.

Critics have also raised concerns that fresh water aquifers could become contaminated through fractures extending from a gas producing zone to fresh water zones.[159] However, whether fracturing fluids or shale gas itself can migrate upward to fresh water zones and cause contamination is unclear. Additionally, critics have argued that questions remain over what happens to the fluids which remain underground.[160] Considering that a large percentage of the injected water and chemicals may accumulate and remain underground, it has been argued that they may disrupt ecosystems and alter the composition of the soil.[161]

A report commissioned by the Canadian Association of Petroleum Producers considers that the probability that fracturing fluids would be able to travel through hundreds or thousands of meters of confining layers of bedrock is extremely low to non-existent.[162] This is because fresh water aquifers are found at depths ranging from 0-150 meters, whereas most shale plays are several hundred meters below these zones.[163] It is noteworthy that it has been acknowledged that there is little direct control over the way in which a permeable fracture network is created, and how this network might then connect to any potentially undetected, pre-existing fracture network.[164] However, according to the Commission, shales in northeastern BC form a natural barrier to fracture propagation because they are clay rich or highly siliceous, high organic in content.[165] This means that the growth of fractures is contained to the targeted shales.

Since approximately one million people in BC rely on groundwater and for many, groundwater is the only source of water readily available[166] protecting the quality[167] and quantity of fresh water aquifers is of public importance.[168] Adequate protection measures are

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[156] See *Drilling and Production Regulation*, BC Reg 282/2010, s 18.
[157] ibid s 10(1).
[158] Healy (n 2).
[159] See e.g. George E King, "Thirty years of gas shale fracturing: What have we learned?" (SPE Annual Technical Conference and Exhibition, Florence, September 2010); Toma Al and others, "Opinion: Potential impact of shale gas exploration on water resources" (April 2012) University of New Brunswick.
[160] Coussens and Martinez (n 153) 69.
[161] ibid
[162] ALL Consulting (n 153).
[163] ibid. See also Oil and gas water use in British Columbia (n 29) 16-17.
[164] Healy (n 2) 9.
[165] See BC Oil and Gas Commission, "Investigation of observed seismicity in the Horn River Basin" (August 2012) (BC Seismicity Report) 9.
[166] L Nowlan, "Buried treasure ground water permitting and pricing in Canada" (Walter and Duncan Gordon Foundation 2005).
[167] Quality concerns are defined by the presence of contaminants (e.g. nitrate, pesticides, volatile organic compounds, fluoride or arsenic) in the aquifer that pose a health risk. See Berardinucci and Ronneseth (n 146) 2.
[168] ibid 47.

critical because fresh water aquifers are highly susceptible to contamination.[169] If contaminants are detected, containing or removing them from an aquifer is often very difficult and costly, resulting the aquifer becoming unavailable for many years, sometimes permanently.[170] Therefore, the most cost-effective groundwater protection actions are preventative in nature.[171] As a result of risks associated with fresh water contamination, provincial regulations highlight the protection of fresh water resources and well construction requirements, specifically well casing design.

2.2.1. Correct handling and disposal of wastewaters

In addition to well construction requirements, correct handling and disposal of wastewaters from hydraulic fracturing is of paramount importance. Although wastewaters contain numerous different chemicals they are not considered as hazardous waste under the provincial legislation. For this reason, wastewaters do not fall within the scope of the *Hazardous Waste Regulation*, 1988,[172] which prohibits the injection of wastewaters into underground rock or soil formations for treatment, storage, or disposal.[173] Underground disposal of wastewaters is facilitated by section 7 of the *Oil and Gas Waste Regulation*, 2005,[174] which stipulates that in accordance with the *Oil and Gas Activities Act*, 2008[175] shale gas operators are authorized to discharge produced water or recovered fluids from a well completion or workover to an underground formation.[176] According to the Commission, suitable disposal formations include depleted hydrocarbon pools or salt water aquifers, which are generally found more than 1,000 m below ground level and are usually isolated from the surface.[177] Although there may be exceptions, in general, water found below 600 meters in BC is saline and thus unsuitable for either domestic or agricultural use.[178] Some of the deep aquifers targeted for disposal have shown a vast capacity for disposal, with limited pressure required at surface for injection.

The Commission documentation reveals that in order to ensure the integrity of underground formations within a disposal zone and thus prevent possible migration of wastewaters into fresh water zones the injection and disposal pressure must be controlled.[179] Since the pressure is based on individual formation properties it is determined during the drilling application approval process, rather than by legislation.[180] Additionally, in order to monitor the injection of fluids and the disposal of wastewaters underground section 74 of the *Drilling and Production Regulation*, 2010[181] stipulates that “the quantity and rate of water, gas, air or any other fluid injected through a well to an underground formation … [must be] metered”. This

[169] See Berardinucci and Ronneseth (n 146) 47. Aquifers’ underground location and rate of flow mean that contamination can go undetected for a long time.
[170] ibid 47.
[171] ibid
[172] BC Reg 63/88.
[173] ibid s 37.
[174] BC Reg 254/2005.
[175] SBC 2008, C 36.
[176] BC Reg 254/2005.
[177] BC Oil and Gas Commission, “Water source, injection and disposal service wells” (1 September 2013) 5.
[178] See Oil and gas water use in British Columbia (n 29) 16-17.
[179] ibid 13.
[180] ibid
[181] BC Reg 282/2010.

requirement can be interpreted to apply to all fluids used during drilling, hydraulic fracturing, and disposal. Operators are required to submit a monthly injection and disposal statement, indicating the quantity of fluid used, no later than 25 days after the end of the month in which the activity occurred.[182] Additionally, disposal formations must be shown to be competent to contain fluid within their area of influence.[183] This is intended to guarantee isolation of wastewaters from fresh water aquifers, which are specifically protected by several provisions of the provincial legislation.

Indeed, the provincial legislation reflects the view that correct handling and disposal of fracturing fluids is important in order to avoid fresh water contamination. Section 20 of the *Drilling and Production Regulation*, 2010[184] stipulates that before the commencement of drilling or the beginning or completion of production, adequate provision is made for the management of gas, formation water,[185] drilling fluids, completion fluids,[186] chemical substances and waste. Surface-control features or measures must be in place in order to contain any uncontrolled flow of gas or liquid waste to any water bodies within the vicinity.[187] Such water bodies can be interpreted to mean both surface and groundwater resources since the *Drilling and Production Regulation*, 2010 stipulates that any wastewaters, liquid waste, chemical substances and refuse from a well, wastewater storage tank or other facility must be dealt with in such a manner that they do not (i) create a hazard to public health or safety; (ii) contaminate any *water supply well*, *fresh water aquifer*, *surface water body*, land or public road; or (iii) pass into any *water body that is frequented by fish or wildlife*.[188]

Groundwater resources, specifically fresh water aquifers are further protected by a number of provincial regulations and acts. Section 10 of the *Environmental Protection and Management Regulation*, 2010[189] stipulates that oil and gas activities taking place on top of an aquifer must ensure that the activity does not cause a material adverse effect on the quality, quantity or natural timing of flow of water in the aquifer. Additionally, section 23(1) of the *Drinking Water Protection Act*, 2001[190] stipulates that nothing must be introduced into a domestic water system, a drinking water source or an adjacent area, or an area of land from which water percolates into a fresh water aquifer[191] which causes a drinking water health hazard in relation to a domestic water system.

In conclusion, the Commission is well aware of the concerns relating to fresh water contamination. Therefore, a number of provisions have been enacted to protect fresh water resources from encroachment by fracturing wastewaters. The requirements for shale gas operators to report disposal and injection activities to the Commission together with the requirements to ensure that disposal formations are carefully selected to guarantee their isolation from fresh water resources seem robust enough to prevent potential fresh water contamination.

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182 BC Reg 282/2010, s 75.
183 See Oil and gas water use in British Columbia (n 29) 16. Suitable disposal formations should have qualities which restrict the upward movement of fracturing waste waters ie they are contained by impermeable cap and base formations.
184 BC Reg 282/2010.
185 subterranean saltwater.
186 i.e. produced water.
187 *Drilling and Production Regulation*, BC Reg 282/2010, s 5(1).
188 ibid s 51(1) (emphasis added).
189 BC Reg 200/2010.
190 SBC 2001, C 9.
191 *Drinking Water Protection Act*, SBC 2001, C 9, s 1.

2.3. Regulation of surface water

In addition to concerns over fresh water contamination, one of the main concerns over the impact of hydraulic fracturing on fresh water resources is the balance between water use by the industry and domestic and agricultural users.[192] Because hydraulic fracturing typically requires large volumes of water, it has been argued to place an additional stress on local surface and groundwater resources.[193] Although the amount of water needed for fracturing operations depends on well depth and length, fracturing fluid properties, fracture job design and the region in which the drilling occurs, the volumes of water needed in Montney Play, BC vary between 10,000-25,000m3 per well. In Horn River Basin, BC, this is 25,000-75,000m3 per well.[194] Since each shale gas installation typically has several wells, the need for water can be substantial.[195] However, the Commission has reacted to the concerns that the industry's water use has an adverse impact on other water users. In 2011 the Commission enacted Directive 2011-02[196] which stipulates that all water sourced from Crown lands is subject to a short term[197] water use permit under section 8 of the *Water Act*, 1996.[198] This is because prior to 2011 a portion of water used by the shale gas industry originated from unrecorded water storage site excavations (borrow pits and water source dugouts).[199]

According to the industry, water is typically extracted from surface water resources, such as lakes and rivers, during periods of high availability and subsequently stored on site in borrow pits or temporary surface lines before being used in fracturing.[200] Alternatively, water may be transported to its destination by road traffic, or operators may also use water supply wells in which case water originates from subsurface aquifers.[201] The industry's argument is that because water withdrawals most frequently take place when surface water bodies are cycling through flood conditions, withdrawals have limited impact on the low-flow characteristics of these water bodies.[202] Another argument used by the industry is that contrary to other industrial uses where water is required on a continuous basis, hydraulic fracturing uses water for short periods.[203] However, this needs to be confirmed based on records of actual use since

[192] See e.g. Coussens and Martinez (n 153) 66.
[193] See Wanga and others (n 27); Precht and Dempster (n 20) Table A-4.
[194] See e.g. Veil (n 23). The projected life of a well is 40 to 50 years, during which one well is fractured at intervals of several years. See Kiviat (n 17).
[195] According to the water management plan of one Horn River Basin based shale gas operator, Nexen, the company needs total 1.2 to 2 million m3 of water for its fracturing operations annually, a volume equivalent to the size of from 480 to 800 Olympic swimming pools. See Zoe Robson, "Shale gas water management responsible development: Nexen Inc Water Management Plan for Dilly Creek Lease, Horn River Basin, NE British Columbia" (Water Technologies Symposium, Fairmont Banff Springs, April 2012) <http://www.esaa-events.com/proceedings/watertech/2012/pdf/P35.pdf> accessed 19 October 2013. The dimensions of one Olympic size swimming pool are 50m x 25m by 2m and it holds 2,500,000 liters or 2500 cubic meters.
[196] Directive 2011-02 Changes in Section 8 short term water use approvals (2 March 2011).
[197] Section 8 authorizes short term use of public waters by oil and gas industry not exceeding 24 months.
[198] RSBC 1996, c 483. This Act vests ownership of all surface waters in the provincial government, and sets out the regulatory process by which the withdrawal of surface water can occur, including the demands of the shale gas industry.
[199] Directive 2011-02 Changes in Section 8 short term water use approvals (2 March 2011).
[200] Forest Practices Board (n 35) 26; Precht and Dempster (n 20) Table A-6. See also Robson (n 195).
[201] Precht and Dempster (n 20) Table A-6.
[202] ibid
[203] J D Arthur and B J Coughlin, "Cumulative impacts of shale-gas water management: considerations and challenges" (SPE Americas E&P Health, Safety, Security, and Environmental Conference, Houston, TX, 2011).

monitoring and reporting water use form an important part of an efficient regulatory regime, considering that fracturing operations require sourcing large volumes of water.[204]

In line with the Commission's aim to monitor and avoid adverse impacts of shale gas development on fresh water resources under Directive 2011-02, operators are required to report their total monthly water usage under section 8 permits to the Commission on a quarterly basis.[205] Water withdrawal data must be reported for each approved withdrawal location, including natural water bodies (e.g. lakes and streams) and man-made water sources (e.g. dugouts). This would appear to guarantee adequate monitoring of industry's water usage. According to the cumulative reported figures of the Commission, the majority of withdrawals in 2013 took place during the first quarter of the year, whereas less water was withdrawn during spring and summer.[206] Although the Commission has not published the details of water withdrawals from the last quarter of 2013, the report from 2012 supports the arguments of the industry that demand for water is not constant, but varies according to seasons.[207]

Additionally, under section 3 of the *Water Act*, 1996[208] the Commission has the authority to suspend section 8 water permits for industrial use during times of low stream flow or droughts in order to ensure adequate water resources for communities and the environment.[209] Under section 3 the Commission may also cancel permits in cases where the permit holder does not comply with permit conditions. Therefore, it appears that that the Commission has reacted promptly to the concerns that the industry's water use may deprive other water users from surface water resources and it has sufficient means to regulate water use should the operators infringe their permit conditions.

Critics have argued that unlike in most industries water from hydraulic fracturing operations cannot be returned to the water cycle for further use, effectively converting clean water into wastewater which must be permanently disposed of. As a result of criticism concerning adverse impacts on fresh water systems operators increasingly treat and re-use flowback water for subsequent fracturing operations.[210] According to the recent report of the Council of Canadian Academies, the industry's goal is to reuse all flowback water during subsequent hydraulic fracturing stages. The report estimates that 90-95% of flowback water is currently recycled, whereas approximately 5-10% is disposed of, for instance, due to its salinity, which reduces the effectiveness in fracturing operations.[211] In BC wastewater from hydraulic fracturing operations is trucked to an approved treatment facility, which is regulated under the provincial *Environmental Management Act*, 2003.[212] After treatment water is pumped into an underground formation using a disposal well[213] approved by the Commission.[214] Critics

[204] Healy (n 2) 21.
[205] Healy (n 2) 21.
[206] Cumulative total volume reported used in the first three quarters of 2013 was 2,143,155. BC Oil and Gas Commission, "Oil and Gas Water Use Summary: Third Quarter 2013 (July-September)" <http://www.bcogc.ca/node/11121/download> accessed 15 March 2014.
[207] BC Oil and Gas Commission, "Water Use in Oil and Gas Activities: 2012 Annual Report" <https://www.bcogc.ca/node/8239/download> accessed 13 May 2014.
[208] RSBC 1996, c 483.
[209] See also BC Oil and Gas Commission, "Water use in oil and gas activities: First Quarter 2013 (Jan-Mar)" <http://www.bcogc.ca/node/8312/download> accessed 19 October 2013.
[210] Council of Canadian Academics (n 76) 50.
[211] ibid
[212] SBC 2003, C 53. See Oil and gas water use in British Columbia (n 29) 7.
[213] Commercial waste disposal sites operated by a third party may be used to dispose of fracturing fluids. At these sites, the disposal wells must be approved by the Commission.

have raised concerns over the capability of wastewater treatment plants treat all chemicals found in fracturing wastewaters.[215]

Although treatment and recycling could be an important factor in mitigating fresh water demand for hydraulic fracturing operations in northeastern BC,[216] technical and economic limitations influence the degree of feasible recycling of flowback water in different areas.[217] For instance, in some areas not enough fluid flows back, or flows back too slowly to the surface, for recycling to be viable.[218] However, to overcome possible uncertainties over the availability of fresh water in the future and to respond to the concerns of the public, some operators have developed voluntary initiatives or operating principles to make reduce negative impacts on the surrounding communities and to protect the environment.[219] Some companies are in the process of developing solutions to use saline water from deep water aquifers, especially in the Horn River Basin where high volumes water are needed for fracturing operations.[220] However, the use of saline water from certain deep water aquifers in this region involves challenges because operators must find a solution to remove hazardous H2S gas or keep the formation water in a closed loop system using the formation pressure, without exposing it to the atmosphere and dispose of returned fracturing fluid to the aquifer after use.[221] Additionally, for salt water to be effective it may be necessary to increase the amount of additives, leading to higher costs.[222]

Although the provincial *Water Act*, 1996[223] is the primary piece of legislation pertinent to the withdrawal of surface water, other provincial and federal laws may supersede it because water is an important component of fish and wildlife habitats.[224] For instance, section 3 of the provincial *Fish Protection Act*, 1997[225] places the needs of fish and fish habitat above the existing water licenses.[226] Section 6(2) of the 1997 Act stipulates that streams and rivers can be designated as sensitive, if the designation is likely to "contribute to the protection of a population of fish whose sustainability is at risk because of inadequate flow of water within the stream or degradation of fish habitat".[227] The designation of rivers as "sensitive" directs the Commission to ensure that the issuance of section 8 permits does not have a significant adverse impact on the sustainability of a protected fish population. Alternatively, a shale gas operator's water permit application must include measures (i) to mitigate significant adverse impacts on fish or fish habitat and/or (ii) to enhance fish or fish habitat elsewhere to fully

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214 Oil and Gas Commission, "Fact Sheet: Hydraulic Fracturing and Disposal of Fluids" September 2011 <http://www.bcogc.ca/node/6025/download> accessed 2 May 2014. Because of its high salinity and the presence of divalent cations, flowback water often needs treatment or more additives before it can be reused.

215 See e.g. Coussens and Martinez (n 153) 67.

216 Elizabeth Johnson and Laura Johnson, "Hydraulic fracture water usage in northeast British Columbia: Locations, volumes and trends" in British Columbia Ministry of Energy and Mines, 'Geoscience Reports' (2012) 57.

217 Council of Canadian Academics (n 76) 50.

218 ibid

219 ibid

220 See Robson (n 195).

221 ibid

222 Council of Canadian Academics (n 76) 50.

223 RSBC 1996, c 483.

224 Todd Hatfield and others, "A review of environmental flow assessment methods for application to Northeastern British Columbia: Consultant's report prepared for the Canadian Association of Petroleum Producers" (August 2012) 9 <http://www.capp.ca/getdoc.aspx?DocId=219634&DT=NTV> 18 October 2013.

225 SBC 1997 c 21.

226 *Fish Protection Act*, SBC 1997, c 21, s 3(2): "To the extent of any conflict between this Act or a regulation under this Act and the *Water Act* or a regulation under that Act, this Act or the regulation under it prevails."

227 ibid s 6(2).

compensate for the significant adverse impact of the proposed shale gas operations.[228] Ultimately, water withdrawal licenses can be refused if "there is a reasonable alternative source of water reasonably available to the applicant".[229] The Commission may also prescribe project specific mitigation measures as a permit condition.[230] Furthermore, a surface water withdrawal may trigger an environmental impact assessment under the *Reviewable Projects Regulation*, 2002,[231] if an operator requires more than 10 million m3 of water per year for its operations.[232] Currently, short term water withdrawals authorized under section 8 of the provincial *Water Act*, 1996 are excluded from the list of projects which require environmental impact assessment.[233]

In conclusion, although the shale gas industry has been criticized for requiring large amounts of water which potentially have an adverse impact on the surrounding communities, fisheries and agriculture, there are efficient measures in place to authorize the Commission to suspend section 8 permits during the times of low stream flow or drought, to protect fish and fish habitats, or for any other reasons which breach an operator's water permit conditions.

2.4. Towards a comprehensive regulation of water use

Whereas section 8 water permits apply to surface water bodies, the provincial government has acknowledged that a more comprehensive legislation is needed to address the on-going use and extraction of groundwater resources in BC.[234] There is a need to ensure that all fresh water resources are sufficiently regulated and monitored because groundwater has a significant role in maintaining base flows in rivers and streams,[235] which in turn are critical for maintaining fish and wildlife habitats, spawning areas and wetlands.[236] The government acknowledges that the lack of adequate rules has resulted in localized conflicts due to concerns about declining groundwater levels, aquifer sustainability and reduced stream flows.[237] Additionally, insufficient integration exists between provisions regulating surface water and groundwater.[238] The provincial government further acknowledges that groundwater is under stress due to a number of reasons, including, *inter alia*, increasing water demands; water quality impacts related to shale gas production; and the growing impact of climate change.[239] Indeed, according to the government, regional hydrology (i.e., quantity, quality, and timing of river flow) is not only altered by large scale water withdrawals, but also

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[228] ibid s 6(6)-(8).
[229] *Fish Protection Act*, 1997, s 6(9).
[230] ibid
[231] BC Reg 370/2002.
[232] ibid Table 9.
[233] Hatfield and others (n 224).
[234] Government of British Columbia, "Water Act Modernization: Regulating ground water use in priority areas and for large withdrawals" (Water Act Modernization) <http://www.livingwatersmart.ca/water-act/groundwater.html> 19 October 2013.
[235] BC Ministry of Environment, "Policy Proposal on British Columbia's new *Water Sustainability Act*" (December 2010) 10 (Proposal on *Water Sustainability Act*) <http://www.livingwatersmart.ca/water-act/docs/wam_wsa-policy-proposal.pdf.> accessed 19 October 2013.
[236] Hatfield and others (n 224) 1-2, 9.
[237] Proposal on *Water Sustainability Act* (n 235).
[238] ibid
[239] Water Act Modernization (n 234).

climatic changes have a key role to play.[240] Climate change is thought to result in, *inter alia*, raising temperatures in BC and elsewhere in northern Canada,[241] changes in precipitation regimes and increases in extreme weather events, such as droughts and floods.[242] Changes in climatic and hydrologic parameters in turn lead to ecosystem changes, which may include habitat loss, altered nutrient cycling, and shifts in geographic ranges and population numbers of certain species of wildlife.[243]

Additionally, it has been acknowledged that current water use practices can result in wastage of water and lowered water levels in adjacent water bodies.[244] Consequently, the provincial government is in the process of preparing legislation according to which all large groundwater uses across the province are likely to become subject to a license or an approval.[245] Additionally, new legislation is envisaged to ensure that surface water bodies, such as fishing rivers and streams, have enough water to maintain stream health to support First Nations fisheries[246] due to concerns that surface water withdrawals may result in negative impacts on fish habitats.[247]

Although the provincial government has identified the legal framework covering groundwater extraction and use as requiring amendment there are some existing provisions concerning withdrawal of groundwater from water source wells. Section 72(2) of the *Drilling and Production Regulation*, 2010[248] stipulates that if water used by industry originates from a water source well, the quantity and rate of water must be metered.[249] Additionally, shale gas operators must report the quantity of water originating from a water source well to the Commission no later than 25 days after the end of the month in which the shale gas production occurred.[250] According to section 68(1) of the 2010 Regulation, an environmental impact assessment under the provincial *Environmental Assessment Act*, 2002[251] is required for groundwater withdrawal rates exceeding 75 liters per second, regardless whether the withdrawn water is saline and non-saline. This is a considerable improvement from the situation in 2002 when major groundwater users did not generally meter their groundwater usage nor was this information publically available.[252]

It also appears that potential impacts of increased water use by shale gas industry on other users are taken into account in the existing legislation concerning section 8 water use permits. Section 15(2) of the *Water Act*, 1997[253] stipulates that the ranking of the several purposes for

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[240] See e.g. K Cozzetto and others, “Climate change impacts on the water resources of American Indians and Alaska Natives in the U.S.” (2013) 120(3) Climatic Change 569, 3.1 DOI: 10.1007/s10584-013-0852-y.
[241] ibid. This causes the permafrost to thaw and snow to melt earlier in the year.
[242] See e.g. Thomas R Karl and others (eds), “Weather and climate extremes in a changing climate” (Department of Commerce, NOAA’s National Climatic Data Center 2008).
[243] Cozzetto and others (n 240).
[244] Water Act Modernization (n 234).
[245] A “large withdrawal” could be in the range of 250 to 500 m3 per day for a well withdrawing water from a fresh water aquifers and 100 m3 per day for wells withdrawing water from saline aquifers. See Proposal on *Water Sustainability Act* (n 235) 9.
[246] Water Act Modernization (n 234).
[247] Forest Practices Board (n 35).
[248] BC Reg 282/2010.
[249] *Drilling and Production Regulation*, BC Reg 282/2010, 72(2). Water usage must be computed as the number of cubic meters it would occupy at standard conditions of 15°C.
[250] ibid
[251] SBC 2002, c 43.
[252] Berardinucci and Ronneseth (n 146) 15.
[253] RSBC 1996, c 483.

which water may be used under licenses are: "from highest rank to lowest rank: domestic, waterworks, mineral trading, irrigation, mining, industrial, power, hydraulic…[fracturing], storage, conservation…purposes". Therefore, domestic water use by communities residing near shale gas production facility takes precedence over industrial uses. This interpretation is further supported by s 72(1) of the *Drilling and Production Regulation*, 2010[254] which stipulates that shale gas operators "must not operate a water source well in a manner that injuriously affects the use of the water source for domestic or agricultural purposes." This suggests that in situations where fresh water resources may be impacted by drought, domestic users have priority over industrial users.[255] Similarly, according to sections 9(1) and 20(1) of the *Environmental Protection and Management Regulation*, 2010,[256] oil and gas activities should be conducted in a way as "not cause a material adverse effect on the quality, quantity or flow of the water to the waterworks or water supply well" located on the operation area or adjacent to it. The regulation further stipulates that if it is impracticable for operators to comply with sections 9(1) or 20(1), they must ensure that any adverse impacts are minimized and the owner or user of the water supply well is given notice at least 72 hours before adversely affecting the water supply. Additionally, the owner or user must be provided with an alternative supply of water of equal or better quality during that period.[257] These provisions are aimed at ensuring that households and agricultural water users are not deprived from fresh water use due to industrial uses. Therefore, it appears that the concerns over sustainable water use by the shale gas industry have been addressed in current and proposed legislation.

III. GAPS IN THE REGULATORY FRAMEWORK

Where the existing legal framework falls short is the lack of requirement for shale gas operators to submit a geologic prognosis design prior to the hydraulic fracturing processes or to conduct microseismic[258] testing or tracking.[259] Although the existing coverage of the Canadian National Seismograph Network for northeast BC is adequate for detecting large, conventional earthquakes, it cannot reliably provide the spatial accuracy necessary to identify smaller seismic events associated with hydraulic fracturing.[260] According to the Commission, more than 8,000 high-volume hydraulic fracturing completions have been performed in the region with no associated anomalous seismicity.[261] However, it appears that seismicity in the region began after hydraulic fracturing commenced.[262] Seismic events in Horn River Basin from 2009 to late 2011 led the Commission to conduct a formal investigation, which concluded that although observed seismicity was caused by fluid injection during hydraulic fracturing operations, only one event was felt at surface and no injuries or damage to property were reported.[263]

[254] BC Reg 282/2010.
[255] Precht and Dempster (n 20) Table A-6.
[256] BC Reg 200/2010.
[257] ibid s 9(2) and 20(2).
[258] Microseismicity is defined as "very low magnitude events created by shear movement or tensile fracture during hydraulic fracturing not detectable by the Canadian National Seismograph Network". See BC Seismicity Report (n 165).
[259] Precht and Dempster (n 20) Table A-4.
[260] BC Seismicity Report (n 165) 26.
[261] ibid 3.
[262] ibid 23.
[263] ibid

The Commission made a number of recommendations as a result of its investigations, including (i) improving the coverage and accuracy of the National Seismographic Network in order to detect all seismic events, (ii) performing geological and seismic assessment to identify pre-existing faulting, (iii) establishing monitoring and reporting procedures for seismic events and requiring immediate suspension of operations upon detection of a seismic event of 4.0 or above on the Richter scale, (iv) gaining a better understanding of ground motion caused by induced seismicity, (v) considering deploying portable, dense seismic arrays to gain a better understanding of seismic events caused by hydraulic fracturing, (vi) requiring reporting of micro-seismic events, and (vii) undertaking a study in the relationship between hydraulic fracturing operations, pumping rates and seismicity.

Although no regulatory requirements to perform geological and seismic assessment exist currently, the Commission issued two compliance Orders for a failure of the operators to install seismology equipment in the last quarter of 2013.[264] It appears that an increasing number of operators have undertaken micro seismic monitoring to map hydraulic fractures.[265] Additionally, companies typically do diagnostic pumping tests or minifracs to estimate reservoir pressure and permeability, following industry best management practices.[266] Geological and seismic assessments are important because hydraulic fracturing inherently involves geomechanical risks due to the injection of large volumes of fluids under high pressure underground.[267] Hydraulic fracturing may also result in seismic activity due to its capacity to change the tendency of existing fractures to open or faults to slip.[268] Therefore, the fact that the Commission has addressed the issue of induced seismicity demonstrates its commitment to respond to the concerns raised by the surrounding communities. However, the Commission must also incorporate its recommendations concerning seismicity into the provincial regulatory framework in order to ensure that hydraulic fracturing does not result in any further seismic activity in the region.

Another pitfall of the current regulatory framework is the lack of baseline water testing before hydraulic fracturing operations begin. Ideally, monitoring studies of nearby water wells, which provide drinking water, should take place before any drilling activity begins.[269] Although the Commission may currently require pre-operation testing for well water quantity and quality as a permit condition in individual oil and gas well approvals, for example, if requested by a landowner during consultations,[270] general pre-operation groundwater testing is not required by legislation or policy.[271] The reason why water monitoring is not part of a compulsory environmental impact assessment for shale gas operations is uncertain because groundwater quantity and quality baseline studies form part of any proposed mining projects in BC.[272] Similarly, groundwater testing is compulsory for shallow coal bed fracturing

[264] BC Oil and Gas Commission, "Quarterly Enforcement Action Summary" (October-December 2013).
[265] Precht and Dempster (n 20) Table A-4. Microseismic monitoring enables operators to establish patterns of seismicity related production activities over time.
[266] ibid
[267] Healy (n 2) 8.
[268] ibid
[269] ibid 21.
[270] Precht and Dempster (n 20) Table A-3.
[271] ibid. See also BC Oil and Gas Commission, "Well Completion, Maintenance and Abandonment Guideline" Version 1.12 (April 2013) para 3.2.1.
[272] Bruce Carmichael and others, "Water and Air Baseline Monitoring Guidance Document for Mine Proponents and Operators (Interim Version)" (BC Ministry of Environment 2012)

operations conducted at a depth of 600 meters or less.[273] Compulsory water testing for these operations must include pre- and post-fracture sampling of water wells within 200 meters of proposed operations where agreed by water well owners.[274] Due to the *ad-hoc* approach towards water testing, there are no established minimum standards or specific chemical parameters to be tested for in the water, but any testing requirements are developed on a case-specific basis.[275] It is unfortunate that water testing is not required systematically since it is seem as critical in detecting possible contamination of groundwater.[276] Testing would also help to limit the environmental and health risks posed by fracturing wastewaters because each fracturing treatment contains a different subset of chemicals.[277]

Although chemical additives account for 0.5-2 per cent of fracturing fluids, some chemical additives may present health and environmental risks. Presence of many genotoxic and carcinogenic chemicals in fracturing wastewaters could lead to short- and long-term survival of flora and fauna, if wastewaters came into contact with the aquatic environment.[278] Additionally, wastewaters could have a detrimental impact on health of humans and farm animals drinking or bathing in contaminated water.[279] Despite the low inclusion rate,[280] the absolute volume of chemicals deployed is likely to be high, given the large volumes of fracturing fluids used.[281] Therefore, some chemicals could be hazardous in sufficient concentrations.[282] Because fracturing wastewaters pose one of the greatest tangible risks to the environment, their effective management is critical.[283] Therefore, the fact that the provincial government has identified a groundwater sampling program as central in sustainable water management and use practices in relation to hydraulic fracturing[284] is a positive development. As such this can be seen as an important step towards even more robust regulatory system.

Lastly, as noted in section 2.1.2, the Commission does not currently require active monitoring of the surface footprint of shale gas operations, apart from hydrogen sulfide content during flaring. However, monitoring could play an important role in reducing air pollution,[285] and therefore it is seen as an integral part of an effective regulatory system. Although harmful effects of air pollution on human health are well-known,[286] there is a relative absence of

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<http://www.env.gov.bc.ca/epd/industrial/mining/pdf/water_air_baseline_monitoring.pdf> accessed 2 May 2014.

[273] Well Completion, Maintenance and Abandonment Guideline (n 271) para 3.2.1.

[274] ibid

[275] Pearson and others (n 83) para 3.2.3. Similarly, there is no general post-operation monitoring for water wells in BC, although monitoring requirements may be imposed on a case-by-case basis. See e.g. Precht and Dempster (n 20) Table A-8.

[276] See e.g. Pearson and others (n 83) para 3.2.3.

[277] See e.g. Precht and Dempster (n 20) Table A-3; Pearson and others (n 83) para 3.2.3.

[278] McDermott-Levy, Kaktins and Sattler (n 27).

[279] ibid

[280] Kavalov and Pelletier (n 47) 22.

[281] ALL Consulting (n 153).

[282] See e.g. Precht and Dempster (n 20) Table A-3; Pearson and others (n 83) para 3.2.3.

[283] See e.g. Osborn and others (n 2); Healy (n 2) 21.

[284] Research to develop provincial water monitoring network is on-going. See eg C J Salas and D Murray, "Developing a water monitoring network in the Horn River Basin, northeastern British Columbia (parts of NTS 094I, J, O, P)" Summary of Activities 2012 (Geoscience BC, Report 2013-1) 135-136 <http://www.geosciencebc.com/i/pdf/SummaryofActivities2012/SoA2012_Salas_Water_Monitoring.pdf> accessed 2 May 2014.

[285] See Precht and Dempster (n 20) Table A-8.

[286] McDermott-Levy, Kaktins and Sattler (n 27).

research on unconventional gas operations on human health.[287] Consequently, scientific knowledge concerning the impacts of unconventional gas operations on the environment and human health is still evolving and this is reflected in the absence of measures in the regulatory framework. In order to protect the atmosphere and human health, effective monitoring would address the concerns of residents living near hydraulic fracturing sites that operators are committed to minimizing all emissions of methane and other compounds.

IV. CONCLUSION

This analysis and evaluation of British Columbia laws governing hydraulic fracturing has demonstrated that the legal framework is rapidly evolving in order to respond to many of the concerns raised by the public. The Commission has made considerable progress in turning the provincial legal framework into a robust one, *inter alia*, by tightening up the rules relating to surface water withdrawals; requiring disclosure of chemicals and additives used in hydraulic fracturing; and conducting an assessment on induced seismicity. Due to the efficient monitoring of shale gas operations, compliance with provincial laws and regulations appears to be good. An effective set of measures such as mandatory reporting and penalties for non-compliance can mitigate public concerns over negative impacts of hydraulic fracturing on the environment and make the operations more acceptable as the public's understanding of potential impacts of hydraulic fracturing increases.

The main weaknesses of the current regime relate to the fact that the legal requirements do not include systematic baseline water testing prior to operations; air quality monitoring or clear rules on extraction and use of groundwater. However, the Commission is in the process of drafting extensive legislation on sustainable and responsible use of both surface water and groundwater. Therefore, the only problem area requiring urgent attention are the measures to monitor air quality in order to minimize impact on the environment and human health.

Although scientific knowledge concerning the impacts of shale gas operations on fresh water resources may be incomplete, the provincial regulations reflect the need to find a fair balance between the interests of shale gas operators and the communities impacted by hydraulic fracturing in order to mitigate any adverse impacts of operations before they cause irreversible damage to the environment and human health. Because shale gas development is still at an early stage in BC, the Commission is in the position to put in place appropriate management measures required to reduce many of the negative impacts of development on the environment and the public. The rapid evolvement of the provincial legislative framework demonstrates that the Commission has taken on board the best practices developed both in Canada and in the US as a result of accidents or near misses and incorporated this knowledge into its policies, processes and procedures in order to ensure continual improvement. This is appears to be a wise policy, considering that there are a number of uncertainties surrounding shale gas production in BC, including the competitiveness of the industry.

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[287] See e.g. Rafferty and Limonik (n 26). Many acute health problems are thought to be common among people living in communities near unconventional oil and natural gas extraction sites, including fatigue; burning eyes; dermatologic irritation; headache; difficulty breathing and the risk of endocrine disruption. McDermott-Levy, Kaktins and Sattler (n 27).

Sanna Elfving, PhD Researcher, University of Surrey.

Expertise in EU law, international trade law and human rights law, specifically the legal mechanisms for the promotion and protection of Indigenous Peoples' rights under international law regimes (UNDRIP, ICCPR, and the ILO Convention 169) and under the State and local levels in Canada, Greenland, Norway and Finland.