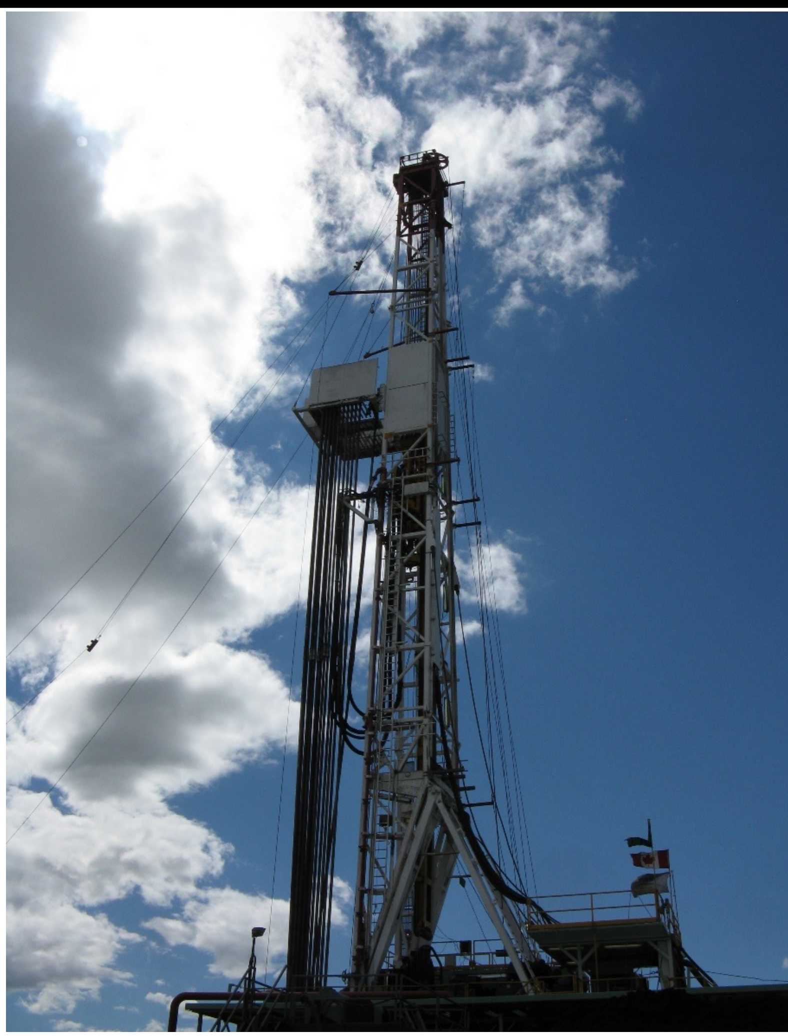
Scientific Review of Hydraulic Fracturing in British Columbia



Scientific Hydraulic Fracturing Review Panel

February 2019

Executive Summary

This report summarizes the findings of the Scientific Hydraulic Fracturing Review Panel (the Panel) tasked by the British Columbia (BC) Minister of Energy, Mines and Petroleum Resources in answering two key questions related to hydraulic fracturing in the Province of BC:

1) Does BC's regulatory framework adequately manage for potential risks or impacts to safety and the environment that may result from the practice of hydraulic fracturing?
2) How could BC's regulatory framework be improved to better manage safety risks, risk of induced seismicity, and potential impacts to water?

In addition, while human health was not specifically included in the terms of reference for the scientific review, the Panel considered human health to be implicit in environmental protection, and thus sought input from experts in public health and toxicology.

The scope of the review included a scientific assessment of potential impacts of hydraulic fracturing on water quantity and quality; and the role of hydraulic fracturing on induced seismicity and fugitive emissions. In conducting its review, the Panel invited topic experts including: BC Oil and Gas Commission staff, industry representatives, academics, environmental consultants, representatives of Treaty 8 First Nations, government (federal, provincial, municipal) staff, representatives of environmental non-government organizations (ENGOs), representatives of industry organizations, and experts from Geoscience BC, Natural Resources Canada, and the Pacific Climate Impacts Consortium. To aid in the review, the Panel also visited several sites in the Fort St. John area, including operating facilities identified as following best practices, sites with known problems, and a research project field site.

To the best of its ability, the Panel carried out this scientific review of hydraulic fracturing in BC with due diligence and respect for the opinions voiced by all participants in the review process. The Panel did not censor concerns raised. The Panel carried out its work in light of the government's adoption and implementation of the United Nations Declaration on the Rights of Indigenous Peoples. All evidence presented to the Panel was considered, as well as evidence in various published and unpublished papers, reports, theses, and webpages; the Panel members did not carry out independent research.

This report is divided into four main sections that address, respectively, water quality, water quantity, induced seismicity, and fugitive emissions. In each section, an overview of concerns raised by experts is followed by a summary of evidence presented to the Panel, additional evidence considered by the Panel, the key findings, and recommendations. In addition to these four main topics, the Panel also addressed impacts to human health, impacts to environmental health, and cumulative effects. However, the Panel could not quantify risk because there are too few data to assess risk. As such, to the best of its ability the Panel addressed the potential risks to human health, safety, and the environment.

Regarding the two questions posed to the Panel, it must first be acknowledged that the activities associated with hydraulic fracturing are diverse (drilling, hydraulic fracturing, transport and storage of fluids, and disposal of fluids). Each activity represents a specific hazard to the environment. Coupled with this diversity is the complexity that arises with activities based in a natural environment, where geology, hydrology, landscape, and climate encompass significant spatial and temporal variability and uncertainty. It is also recognized that there are other activities associated with agriculture and resource development (e.g. forestry and mining) that have overprinting impacts on the environment. Specific to oil and gas development, there is also the legacy of historical practices that have seen considerable advances in technology and changes to regulations, and consequential changes in impacts to the environment.

Does BC's regulatory framework adequately manage for potential risks or impacts to safety and the environment that may result from the practice of hydraulic fracturing? The very rapid development of shale gas in NEBC has made it difficult to assure that risks are being adequately managed at every step. Furthermore, the Panel could not quantify risk because there are too few data to assess risk. Nevertheless, it is the view of the Panel that the current regulations under many acts appear to be robust. At the same time, insufficient evidence was provided to the Panel to assess the degree of compliance and enforcement of regulations. One of the challenges with the current, generally non-prescriptive (i.e. objectives based) regulatory regime, is that most of the details for environmental protection are not transparent; rather they are embedded within various permitting processes or industry best practices or guidance documents. This is particularly problematic when there is shared regulatory responsibility, for example, concerning dams, spills and leaks, and disposal wells. From a public perception perspective, the various activities associated with hydraulic fracturing appear to be unregulated, and this leads to fear and mistrust of the regulators. There are clear advantages to having a single window regulator for the oil and gas industry (e.g. to issue water permits, and to monitor and enforce oil and gas industry compliance with relevant environmental laws); however, this model comes at a cost in terms of public confidence. Certainly, aspects of the current shared regulatory responsibility (in regard to the construction of dams and sales of water to industry by private landowners) have led to unresolved problems.

How could BC's regulatory framework be improved to better manage safety risks, risk of induced seismicity, and potential impacts to water? A repeated theme expressed to the Panel, is the value of targeted research to address important knowledge gaps and concerns regarding environmental impacts. A prime example is the increased water footprint that accompanied unconventional gas development; the rapid development of the industry and use of hydraulic fracturing saw the use of unprecedented amounts of freshwater, and after, wastewater disposal. However, pressures caused by this need for freshwater has led to research successes in the recycling of wastewater for hydraulic fracturing, which has quickly, and significantly, reduced fresh water needs. This one advancement presents a significant step-change in reducing key concerns regarding water quantity. It was the experience of the Panel that many of the expert presentations identifying key knowledge gaps emphasized the need for further research. As an “unconventional” energy resource, experience with shale gas development is in its early days. It is the Panel’s opinion that research is needed to support the responsible development of BC’s shale gas resources. Uncertainties regarding the impact of its development on communities and the environment, and therefore risks, can be reduced through a coordinated research effort focused on the unique BC context. Rising to meet these challenges will require a more detailed accounting of existing knowledge gaps and addressing these with science-based solutions to minimize and mitigate impacts, while also building public confidence. A “By British Columbia for British Columbia” strategic research partnership would be well placed to foster relationships between regulator, industry, First Nations, and the public. Ultimately, best-practice regulations founded on a body of peer-reviewed science can be used to inform the regulatory framework that protects the environment without unnecessarily encumbering development, while providing confidence to the public that the province’s resources are being developed responsibly.

Table of Contents

1. Introduction

1.1. Panel's Mandate

The Scientific Hydraulic Fracturing Review Panel (the Panel) was formed by the British Columbia (BC) provincial government with the mandate to review the practice of hydraulic fracturing in BC in the context of ensuring that hydrocarbons are produced safely and the environment is protected; and provide the Province with its findings and advice on the following:

1. What role hydraulic fracturing has in induced seismicity in Northeast BC (NEBC), and
2. What impacts hydraulic fracturing has on water quantity and quality.

During the initial meeting of the Panel in February, 2018, the Panel expanded the mandate to include:

3. What role hydraulic fracturing has on fugitive methane emissions.

The three-member independent Panel was responsible for collecting information and evidence from academics, industry, NEBC communities, Treaty 8 First Nations, environmental organizations, and the scientific literature to specifically answer two questions:

a) Does BC's regulatory framework adequately manage for potential risks or impacts to safety and the environment that may result from the practice of hydraulic fracturing?
b) How could BC's regulatory framework be improved to better manage safety risks, risk of induced seismicity, and potential impacts to water?

While human health was not specifically included in the terms of reference for this scientific review, the Panel considered human health to be implicit in environmental protection. None of the Panel members has expertise in human health, and therefore, the Panel sought input from experts in toxicology and public health. Public health takes into account physical, mental, and social well-being, and so has broad scope encompassing not only toxicological impacts, but also impacts to emotional and spiritual wellbeing.

In addition, the Panel carried out its work in light of the government's adoption and implementation of the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP). Articles 25, 29 and 31 of the declaration are particularly relevant in this regard. Under UNDRIP, Indigenous peoples have a right to clean water and government has a duty to ensure Indigenous peoples have a right to food and water. For this reason, the Panel carefully considered First Nations' right to "peaceful enjoyment." The Panel acknowledges Indigenous peoples' spiritual, rather than solely material, connection with water.

This report documents the findings and advice to the Province on hydraulic fracturing. The report is structured into four main topical sections: Water Quantity (Section 3), Water Quality (Section 4), Induced Seismicity (Section 5), and Fugitive Emissions (Section 6). Background information on hydraulic fracturing and an overview on the current regulatory regime precedes these main sections (Section 2). This report ends with a section on risk, from the perspective of impacts on human health (Section 7.1), impacts on the environment (Section 7.2), risk to safety (Section 7.3), and cumulative effects (Section 7.4). The report concludes with broad advice to government and concluding remarks. Recommendations specific to each topic are presented in the respective subsections.

1.2. Panelists

The independent Panel, who were appointed on a voluntary basis, consists of three recognized experts, Dr. Diana Allen, Dr. Erik Eberhardt, and Dr. Amanda Bustin. The panelists have scientific and technical backgrounds and knowledge in areas relating to environmental management, water, induced seismicity, and hydraulic fracturing. While sections of the report were written by individual panelists, Panel members reviewed all sections of the report and all decisions were made by consensus. Advice on traditional Indigenous knowledge was provided to the Panel by Ms. Nalaine Morin. The Panel was supported by a third-party Facilitator and by a Secretariat staff provided by the Ministry of Energy, Mines and Petroleum Resources (MEMPR).

Biographies for the panelists and the advisor are included in Appendix A.

1.3. Review Process

The framework for the review process was developed during two Panel meetings in Vancouver on February 23rd and April 16th, 2018.

The first Panel Proceedings (sessions) were held in Fort St. John the week of May 14th, 2018. The week consisted of:

1. A broad overview of the regulatory framework from the BC Oil and Gas Commission (BCOGC).
2. Site visits to:
    a. facilities identified as following best practices;
    b. sites with known problems; and
    c. a research project field site.
3. A roundtable, without a structured agenda, with representatives who spoke on behalf of Treaty 8 First Nations.
4. Consultation with the Municipality of Dawson Creek.

The Panel then held in-person and teleconference sessions in Vancouver over eight days between May and July, 2018, and in-person sessions in Fort St. John over two days in June, 2018. Additional teleconference sessions were held in October, 2018 with experts who were unavailable during the scheduled sessions. The Panel-invited topic experts included: BCOGC staff, industry representatives, academics, environmental consultants, representatives of Treaty 8 First Nations, government (federal, provincial, municipal) staff, representatives of environmental non-government organizations (ENGOs), representatives of industry organizations, and representatives from Geoscience BC and the Pacific Climate Impacts Consortium (PCIC). The Alberta Energy Regulator (AER) declined the invitation to present to the Panel. A schedule of the expert presenters to the Panel is included in Appendix B.

Each session was one hour in length, with a 20- to 40-minute scientific presentation by the expert(s) including:

- scientific review of current data and state of practice;
- the key challenges faced in their area of expertise;
- specific things being done/actions being taken to mitigate challenges;
- discussion of the effectiveness of existing regulations;
- knowledge gaps - things we know and do not know;
- how knowledge gaps are being addressed or could be addressed; and
- what is on the horizon regarding the state of the art and other research advances.

A discussion period followed the presentations. The audio from the Panel proceedings were recorded, and copies of PowerPoint presentations and supporting information were provided to the Panel. The experts were also asked to prepare a one-page summary of their presentation one week prior to their session.

A structured agenda was not used for the full-day session with representatives who spoke on behalf of Treaty 8 First Nations. The session was a roundtable discussion without formal presentations nor prepared documents. The Panel initially planned to include a subsection on traditional Indigenous knowledge in each of the four main topical sections. However, while the representatives who spoke on behalf of Treaty 8 First Nations shared concerns regarding hydraulic fracturing and provided examples, they were reticent to share more broadly their traditional knowledge. As a result, the Panel included the concerns and examples heard from the representatives who spoke on behalf of Treaty 8 First Nations throughout the report without specific subsections on traditional knowledge.

2. Background

2.1. British Columbia's Oil and Gas Industry

The oil and gas industry has been active in British Columbia for more than 100 years, and has grown and evolved with provincial legislation regulating its exploration and development. The first officially recorded well was drilled in the Fraser Delta in 1906. This early exploration was marked by sparse and sporadic drilling, mostly in accessible parts of the province such as the Fraser Delta and Crowsnest Pass (Janicki 2008). However, most of the successful activity after this initial period has been concentrated in the northeastern part of BC, which lies on the western margin of the Western Canadian Sedimentary Basin, one of the world's largest reserves of oil and gas.

Oil and gas activity in NEBC began in the 1920s with the drilling of several exploration wells in the Peace River area by the provincial government to test the potential for oil and gas development. This coincided with the first legislative Act in 1924 to regulate coal, petroleum, and natural gas development, which led to the *Petroleum and Natural Gas Act* of 1947 administered by the then Department of Lands and Forests. The first successful natural gas well in the Peace River area (and BC) followed in December 1947. By the mid-1960s, substantial natural gas recoveries provided the impetus for building the infrastructure required to deliver the gas to market (Janicki 2008). The BC natural gas industry continued to grow from this point for the next 40 years, producing from shallower and then deeper conventional gas formations.

In 1998, the BC Oil and Gas Commission (BCOGC) was established and took over all regulatory aspects of oil and gas activities in the province. This coincided with technological advancements in horizontal drilling combined with hydraulic fracturing, which opened up opportunities in deeper, previously uneconomical formations in NEBC (as elsewhere). These "unconventional" gas plays would target gas-bearing rocks with extremely low permeabilities (siltstones, shales) that prevent the resource from being extracted economically through vertical wellbores and conventional completions. Horizontal wellbores permit increased access to the reservoir rock and multi-stage hydraulic fracturing allows for increased permeability of the rocks to achieve economic production. These resources are commonly referred to as shale gas.

Increasing gas prices accelerated drilling activity in the 2000s, resulting in a transition in NEBC from conventional to unconventional natural gas development. By 2007, interest in the shale gas basins in NEBC was setting new records in revenue from oil and gas rights, and by 2011, production from unconventional gas surpassed conventional gas (Figure 1). Today, more than 85% of BC's natural gas production is unconventionally sourced (BCOGC 2016)[1].

[1] British Columbia's Oil and Gas Reserves and Production Report: https://www.bcogc.ca/node/14704/download

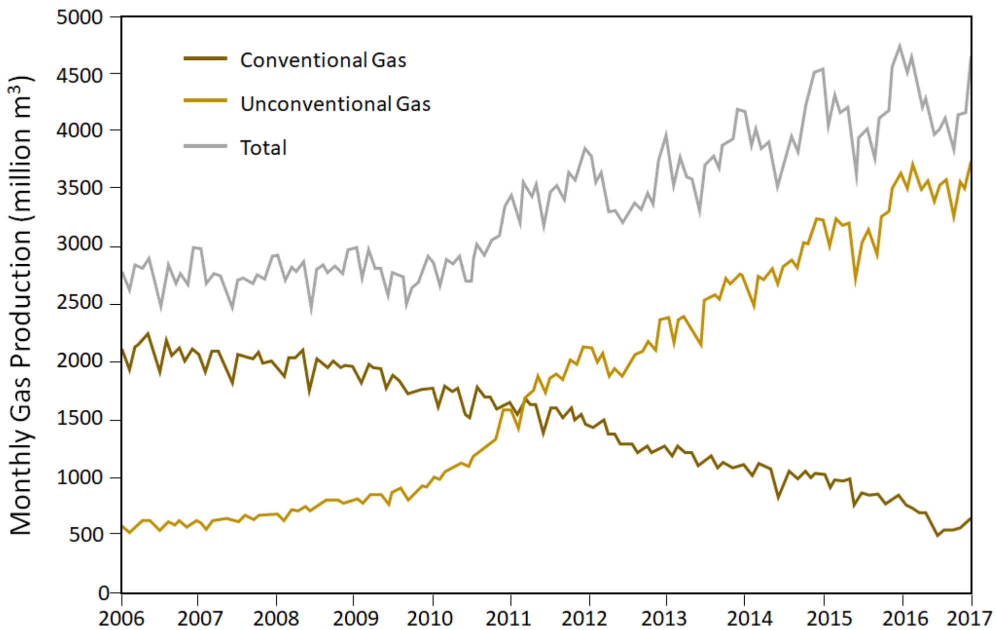


Figure 1. Conventional versus unconventional gas production in BC. Source: BCOGC 2016[2]*.*

In terms of market size, Natural Resources Canada[3] reports that BC produces 25% of all natural gas in Canada, next to Alberta at 74%, and that Canada ranks 4th in global production (5%) compared to the U.S. in 1st (20%). Remaining raw gas reserves in NEBC (i.e. known recoverable gas) were estimated by BCOGC (2016) at the end of 2016 to be 48.37 trillion ft^3 (1.37 trillion m^3), compared to the 7.33 trillion ft^3 (0.21 trillion m^3) produced to date, indicating that 85% of reserves are remaining.

2.2. Overview of Hydraulic Fracturing

Hydraulic fracturing is the process by which fluids are injected under pressure down a wellbore and into a targeted rock formation to generate fractures. This has several applications including those for mining and enhanced geothermal system projects, but is most widely associated with the oil and gas industry. For the purpose of this report, hydraulic fracturing is defined here specific to its use to develop unconventional oil and gas resources. This includes (Figure 2):

[2] British Columbia’s Oil and Gas Reserves and Production Report: https://www.bcogc.ca/node/14704/download

[3] Natural Resource Canada’s Natural Gas Facts (2018): https://www.nrcan.gc.ca/energy/facts/natural-gas/20067

- the process used to increase the permeability of low permeability reservoir rock by generating fractures to open flow paths to access and extract the natural gas resource;
- the water cycle (sourcing and use of water, handling of wastewater, and disposal of wastewater);
- induced seismicity derived from the injection of fluids into deep formations for both the purpose of hydraulic fracturing and wastewater disposal; and
- fugitive gas emissions from well drilling and completions.

It does not include the transmission of oil or natural gas, land use, economic or social science matters.

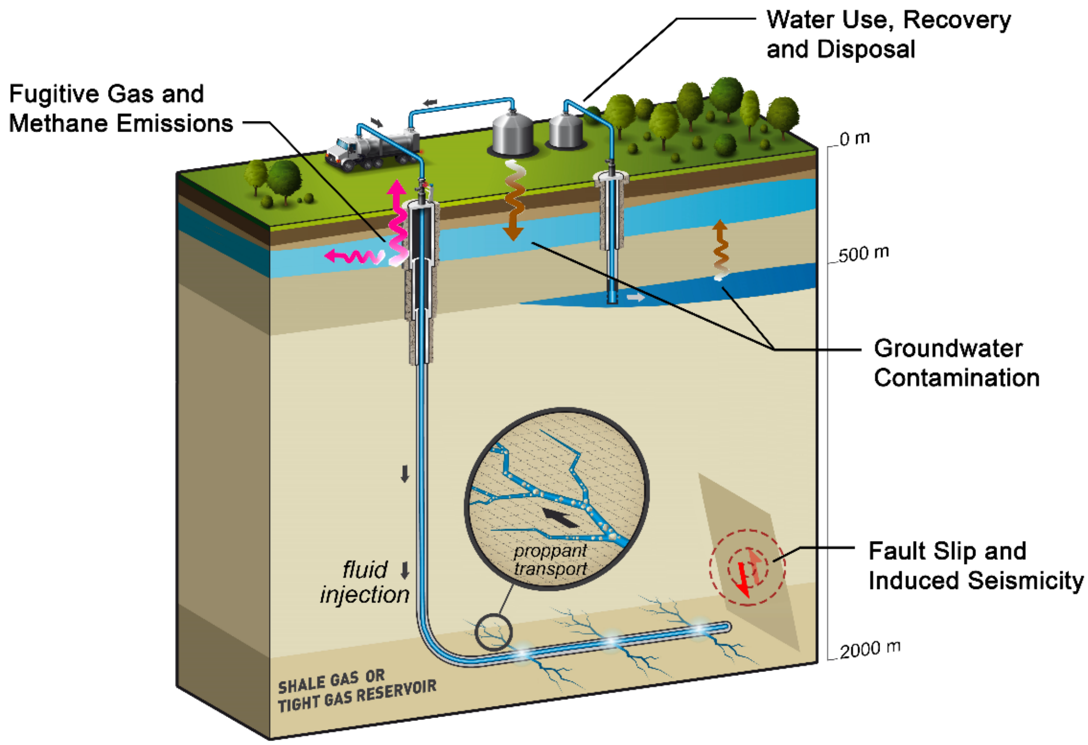


Figure 2. Environmental concerns associated with multistage hydraulic fracturing operations for unconventional gas development. Source: Eberhardt and Amini (2018).

Hydraulic fracturing has been used in BC since the 1950s. It was first introduced in the oil and gas industry in the U.S. in the late 1940s to enhance conventional oil production. The first wells treated saw an average increase in production of 75%, leading to a rapid growth in its application (Montgomery and Smith 2010). By the mid-1950s, more than 100,000 individual hydraulic fracturing treatments had been performed in vertical wellbores in the U.S. (Hubbert and Willis 1957). Records indicate that hydraulic fracturing was introduced in Canada at this time, in Alberta and BC, also in the development of conventional oil and gas resources.

Hydraulic fracturing saw its next step change in the 1990s when it was combined with advancements in horizontal drilling to improve the viability of low permeability unconventional oil and gas resources, particularly shale gas. To free the trapped gas, these treatments include the pumping of a mixture of water, proppant (typically sand), and a small percentage of chemical additives down the wellbore at sufficient pressure to not only fracture the rock but also to prop open the fractures to maintain the flow paths created. Water comprises 90-95% of a typical “frac fluid” mixture followed by 4.5-9.5% proppant and 0.5% chemical additives. Commonly added chemicals include: friction reducers (i.e. “slickwater”) to modify the fluid flow behaviour to help transport proppant farther; acids to clean the perforations and help initiate cracking; biocides to reduce equipment corrosion from acid producing bacteria as well as bio-clogging of fractures that can inhibit gas extraction; surfactants to change wettability; crosslinkers to increase viscosity for proppant transport; and breakers to then reduce the viscosity for improved flowback recovery. The use of biocides also allows the use of recycled water by preventing souring using sulfate reducing bacteria, helping to minimize water use and wastewater volumes (King 2010).

Water use in BC during hydraulic fracturing is reported by Rivard et al. (2014) as ranging from 2,000 to 100,000 m^3 per well. This high degree of variability reflects the dependence of water use on the treatment type, number of fracture stages, and targeted formation. In NEBC, three types of hydraulic fracturing treatments are generally used: slickwater, energized, and energized slickwater (Johnson and Jonson 2012). Slickwater treatments use higher volumes of water (together with friction reducers) to propagate large fractures and move proppant when targeting brittle heterogeneous rocks. Energized treatments use comparatively smaller amounts of water, relying instead on the use of foams and polymers to move proppant when treatments are in softer, more ductile rocks. Johnson and Jonson (2012) report average water use in the Montney Trend where energized treatments are favoured as 1,900 m^3 per well, or 250 m^3 per fracture stage. This increases to 7,800 m^3 per well, or 1,000 m^3 per fracture stage, in the Montney North Trend where hybrid-energized slickwater treatments are favoured. For the Horn River region (Muskwa-Otter Park Formation), where slickwater treatments are favoured, this increases further to 34,900 m^3 per well, or 2,000 m^3 per fracture stage. The Panel notes that due to changes in hydraulic fracturing technology over the past few years, these reported water use estimates may be outdated.

Shale gas wells are often ‘’shut-in’’ for varying lengths of time, typically days to weeks, following the hydraulic fracturing operation (Bertoncello et al. 2014). Following shut-in, production of gas and water from the well commences. The initial production is dominated by returning fracturing fluid (i.e. ‘flowback’’ water) mixed with formation water (i.e. produced water). Water flow rates are initially high but typically decrease rapidly until very little water is produced (Clarkson and Williams-Kovacs 2013). In NEBC, between 5 to 90 percent of the hydraulic fracturing fluid injected is recovered (BCOGC 2011[4]; Owen 2017). Johnson and Jonson (2012) indicate that returned water volumes (like water use) depend on the treatment type; whereas returned water for energized wells in the Monterey can be greater than 50%, in the Horn River for slickwater wells this decreases to 17%. Recently, there has been a shift towards recycling produced and flowback water for subsequent hydraulic fracturing treatments. BCOGC estimates that approximately 40% of produced and flowback water is currently reused in hydraulic fracturing operations.

At surface, the gas and water are separated and the natural gas is moved via pipelines for additional processing, after which it generally enters the pipeline transmission systems for delivery to markets. Studies investigating the producing life of unconventional gas wells indicate that they experience a sharp decline in production in their first few years; for example, data from the Eagle Ford shale gas play in Texas show initial production levels decreasing by up to 80% after two years (Guo et al. 2016). Zhang et al. (2016) explain that this reflects the production from the higher permeability rock created by hydraulic fracturing (referred to as the stimulated reservoir volume), after which the production rates transition to a slower exponential decline as production starts to deplete the un-hydraulically fractured low permeability shale rock.

Another shift to reduce the environmental footprint of unconventional gas development is the move towards fewer but more intensive multi-well pads to reduce the total surface disturbance. Previously, each conventional gas wellbore would be drilled from a single well pad. With horizontal wellbores now capable of extending out several kilometres with numerous hydraulic fracturing stages in a single well, one long horizontal well can replace 15 or more vertical wells (Figure 3). Building on this reduced surface footprint, “super pads” and “cube developments” are being designed to house up to 36 horizontal wellbores, occupying less than 1% of the surface area over which the reservoir is being produced (Dembicki et al. 2015).

Today, it is estimated that more than 2.5 million hydraulic fracture treatments have been carried out worldwide, and that hydraulic fracturing has increased recoverable reserves of oil in the U.S. by at least 30% and of gas by 90% (Montgomery and Smith 2010). BCOGC[5] reports that 98% of wells that commenced production in 2016 were hydraulically fractured.

[4] BCOGC September 2011 fact sheet: http://fracfocus.ca/sites/default/files/publications/hydraulic_fracturing_and_disposal_of_fluids_final.pdf

[5] BCOGC Hydraulic Fracturing Fact Sheet: https://www.bcogc.ca/node/11416/download

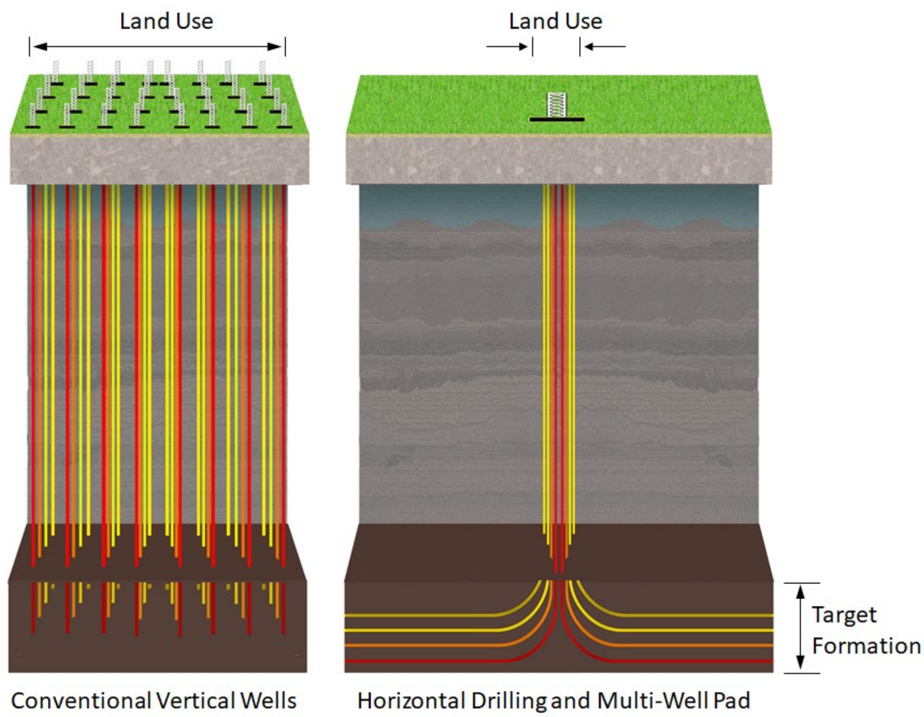


Figure 3. Comparison of land use between conventional vertical wellbores drilled from multiple single well pads and horizontal drilling from a single multi-well pad. Modified after Energy of North Dakota outreach and education program.

2.3. Overview of the Hydraulic Fracturing Water Cycle

The U.S. Environmental Protection Agency (U.S. EPA) (2016) defines five stages and activities in the hydraulic fracturing water cycle. These include:

- **Water Acquisition:** the withdrawal of surface or ground water to make hydraulic fracturing fluids. For 2017, BCOGC reported that a total of 3.6 million m^3 of water was withdrawn for all oil and gas activities, predominantly from river sources (1.6 million m^3 through long-term water licences, and 2 million m^3 through short-term water approvals)[6].
- **Chemical Mixing:** the mixing of the water with proppant and additives at the well site to create hydraulic fracturing fluids. As previously noted, between 90 and 95% of the hydraulic fracturing fluid mix is water.

[6] BCOGC (2017). Quarterly Oil and Gas Water Management Summary, Fourth Quarter 2017 (October - December): https://www.bcogc.ca/node/14920/download

- **Well Injection:** the injection of the hydraulic fracturing fluids to generate fractures and stimulate gas production in the targeted rock formation. Injections in NEBC use between 10,000 to 70,000 m^3 per wellbore[7].
- **Wastewater Handling:** the on-site collection and handling of water that returns to the surface through the wellbore, including both the recovered hydraulic fracturing fluid (flowback) and saline formation waters produced with the gas during its extraction. As previously noted, (BCOGC 2011) reported that between 5 to 90% of the injected hydraulic fracturing fluids are recovered.[8]
- **Wastewater Reuse and Disposal:** the reuse of the flowback and produced waters (collectively referred to as wastewater) for other hydraulic fracturing treatments, and eventually disposal. BCOGC estimates that approximately 40% of wastewater is currently reused in hydraulic fracturing operations.

Because local water resources often vary across a region, water management approaches may differ from one operation to another, while also adapting to different geological factors, operational needs, and local community and First Nations concerns.

Provincial statutes (discussed in Section 2.5) outline how the oil and gas industry must ensure that water resources are protected during hydraulic fracturing activities. A number of measures are required to protect the water supply, such as minimum setbacks to maintain distance between water wells and drilling operations and minimum vertical separation between the shallow groundwater zone and “deep groundwater.” Unlike other jurisdictions that set arbitrary depths above which oil and gas activities cannot be carried out, under the *Water Sustainability Act* (WSA) “deep groundwater” is defined hydrogeologically so as to distinguish it from the shallow groundwater zone (i.e. depth of usable groundwater) (see Section 3.3.2).

Steel surface casing cemented along its full length is mandatory for oil and gas wellbores and must extend to a minimum depth of 600 m. BCOGC (2018)[9] defines usable water as groundwater with up to 4,000 mg/L of total dissolved solids, and the maximum base of useable groundwater to be at 600 m depth below surface (as defined under the WSA). This is in contrast to the depth of unconventional gas target zones and hydraulic fracturing, which in BC are typically at a depth of 2,000 to 3,200 m (Figure 4).

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[7] BCOGC How much water is used?: https://www.bcogc.ca/how-much-water-used

[8] BCOGC (2011). Hydraulic Fracturing and Disposal of Fluids Fact Sheet: http://fracfocus.ca/sites/default/files/publications/hydraulic_fracturing_and_disposal_of_fluids_final.pdf

[9] BCOGC (2018). Oil & Gas Operations Manual, v 1.22: https://www.bcogc.ca/node/13325/download

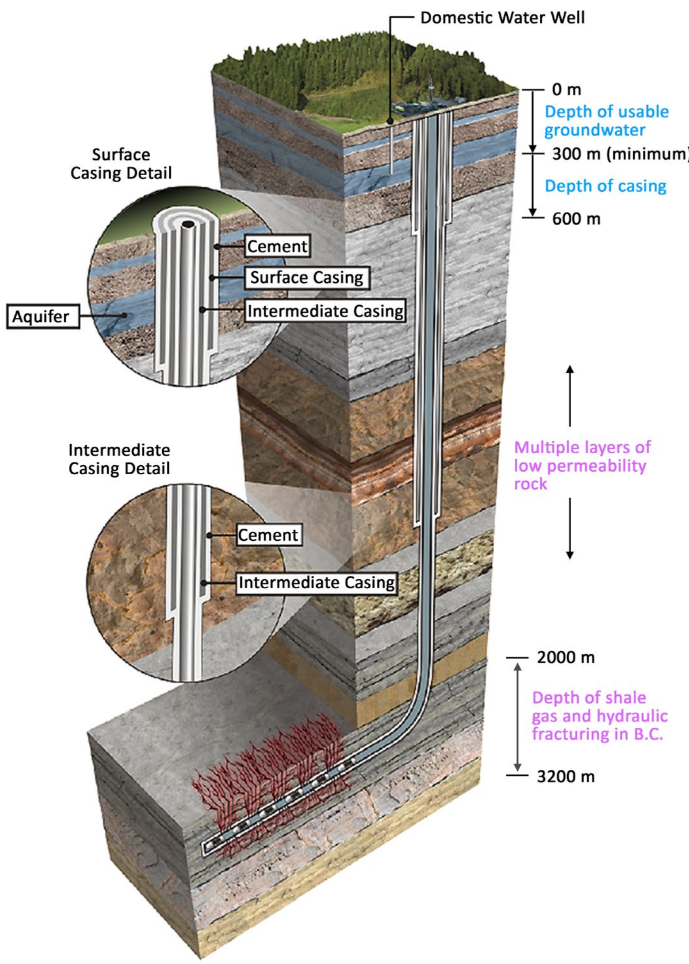
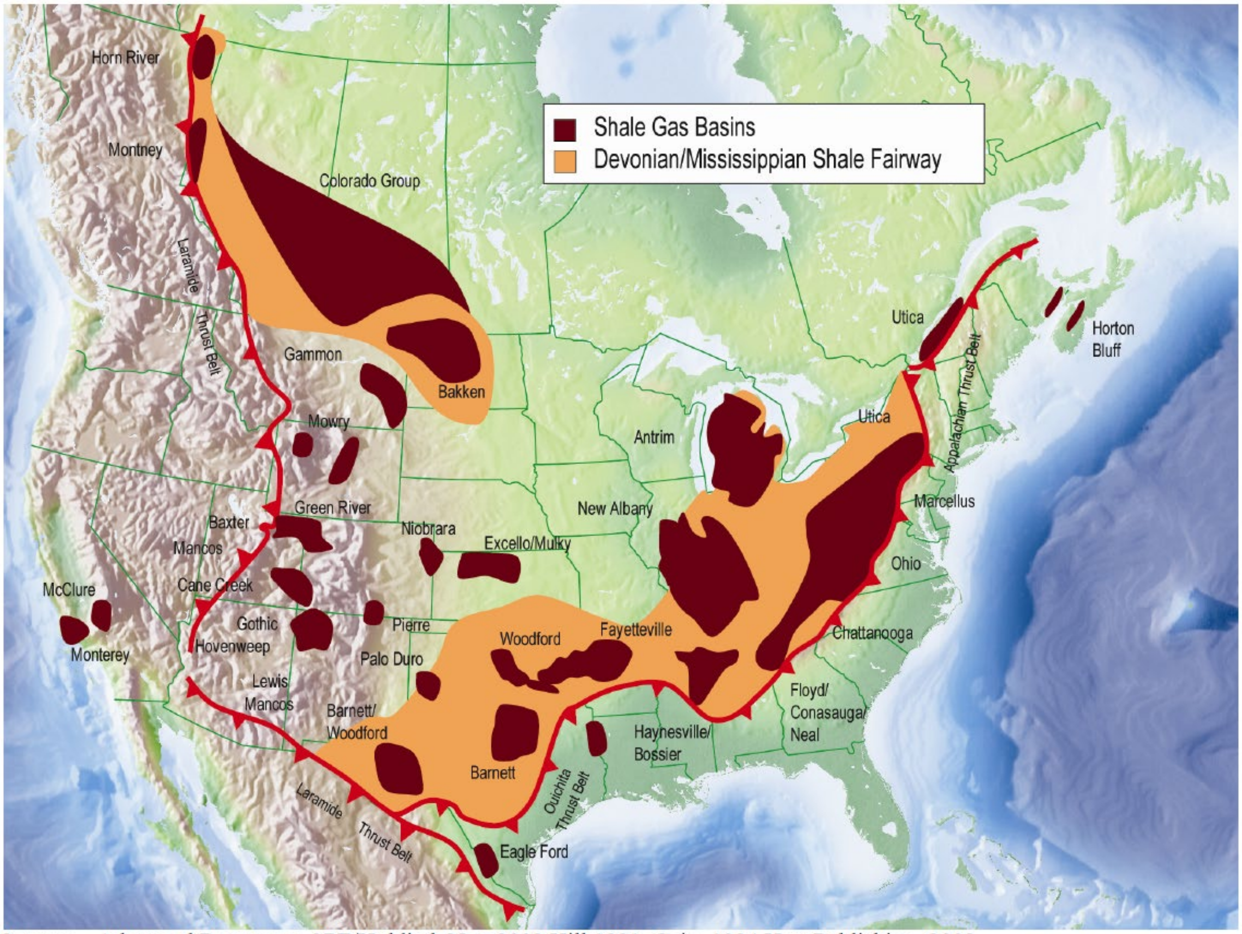


Figure 4. Depth of usable groundwater relative to depth of shale gas and hydraulic fracturing in NEBC. Modified after CCA (2014) and Apache Canada.

2.4. Overview of BC Setting Versus Other Shale Gas Regions

Although concerns regarding hydraulic fracturing activities are common across the different unconventional gas plays in North America (see Figure 5 for map), it is important to understand that the depths, geological conditions, and operational practices involved can differ significantly. Concerns and challenges encountered in one region might be different from those in another region. Different regulatory and non-regulatory requirements together with the history of conventional versus unconventional gas development and ability to adapt to new technologies and practices, can likewise vary from region to region.



Source: Advanced Resources, SPE/Holditch Nov 2002 Hill 1991, Cain, 1994 Hart Publishing, 2008 modified from Ziff Energy Group, 2008.

Figure 5. Map of North American shale gas basins and plays. Source: National Energy Board (2009).

For example, BCOGC[10] report that in 2007, 85% of wells in NEBC targeted conventional gas, but by 2016, 98% of producing wells were drilled using horizontal drilling technology to target deep unconventional resources. In contrast, the Pennsylvania Department of Environmental Protection (PDEP)[11], report that in 2017, 89% of producing wells in the Marcellus in Pennsylvania were still conventional wells. Thus, where there are recognized cases in the Marcellus of oil and gas activities having adversely affected private water supplies (PDEP 2017), it is also noted that these circumstances involve a high density of conventional wells (i.e. larger surface footprint) combined with a higher population density compared to more remote shale gas plays such as those in NEBC. This is not to say that there are not similar concerns in NEBC, but that the operational situation and history of practices is significantly different and, more

[10] BCOGC Factsheet on Unconventional Gas: https://www.bcogc.ca/node/11473/download
[11] PDEP 2017 Annual Report: https://www.depgis.state.pa.us/2017oilandgasannualreport/index.html

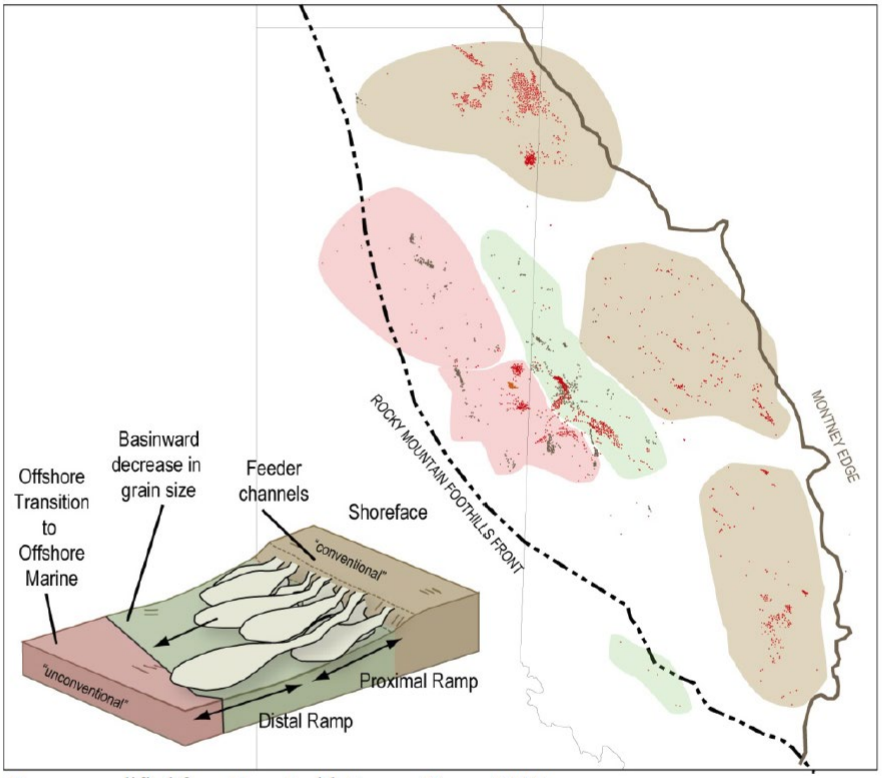
generally, comparisons of experiences between different shale gas regions are not always applicable.

Even within the same region, operational practices and concerns may vary owing to differences in the exact geological conditions and processes (and their evolution over millions of years) that served to create each shale gas basin. In NEBC, unconventional gas development has been largely focussed on the Montney and Horn River plays (Figure 5). The Montney Formation spans a wide variety of depositional environments that date to the Lower Triassic (250 million years ago). Towards the east, more porous sandstones and shale beds were deposited in shallower water environments (Figure 6). These would be more characteristic of conventional oil and gas plays. However, most of the Montney Formation lies to the west and consists of siltstone containing small amounts of sandstone that originally collected on the bottom of a deep sea. These offshore marine sediments are the target of BC's unconventional gas development. This part of the Montney is over 300 m thick in some places allowing operators to pursue stacked horizontal wells targeting multiple depths from the same well pad, producing from both the Upper and Lower Montney. A large proportion of the Montney play also benefits from the presence of liquids rich gas.

For comparison, the Horn River basin targets older mid-Devonian rocks (390 million years old). These are largely organic-rich, deep basin, black shales found in multiple formations (the Muskwa, Otter Park, and Evie). The multiple formations allow stacked horizontal well development. Due to the greater depths and corresponding higher temperatures and pressures, relative to the Montney, the recoverable gas in the Horn River is sweet dry gas. As a result, current development in the Horn River has ceased as operators await higher gas prices, whereas in the Montney, drilling activities continue, concentrating on the liquids rich gas portions of the play (BCOGC 2016)[12]. This difference in the characteristics of the gas being produced is another example of the influence that geology plays.

Comparing NEBC shale gas plays to those in the U.S., the influence of geology on the depth of the resource is an important differentiating factor. Hydraulic fracturing activities in NEBC are particularly deep, and although the average depth of hydraulic fracturing in the U.S. at 2,500 m is similarly deep, Jackson et al. (2015) found that many wells (approximately 16% of those drilled between 2010 and 2013) were hydraulically fractured at depths of less than 1,600 m. These shallower wells typically are seen as having greater environmental risks associated with hydraulic fracturing activities. In the Marcellus, violations in Pennsylvania related to the casing and cementing of shale gas wells leading to concerns of fugitive gas emissions, appear to cluster around concentrations of shallow wellbores targeting shallower gas bearing formations (Walker et al. 2012). Shallow wellbores are seen to increase the potential for gas migration pathways to develop through and around the wellbore cement contributing to fugitive gas escape.

[12] BCOGC (2016). British Columbia's Oil and Gas Reserves and Production Report. B.C. Oil and Gas Commission: https://www.bcogc.ca/node/14704/download



Source: modified from Ross Smith Energy Group, 2008.

Figure 6. Geological model of the unconventional gas plays in NEBC, using the Montney as an example. Shown is the relationship between conventional gas plays in green and unconventional gas plays in pink. Source: National Energy Board (2009).

At the other end of the spectrum, in Oklahoma, it is not hydraulic fracturing targeting the Woodford shale that has been identified as the source of the sharp rise in induced seismicity they've experienced, but the injection of wastewater (produced from hydraulic fracturing) that targets an even deeper formation, the Arbuckle (Hincks et al. 2018). This deep injection has been linked to interacting with critically stressed faults in the crystalline basement triggering seismicity (Walsh and Zoback 2015). Similar experiences have been reported in the Marcellus involving injection in formation near the crystalline basement triggering induced seismicity (Skoumal et al. 2018). In contrast, induced seismicity experienced in NEBC has more often been linked to hydraulic fracturing in the Lower Montney or the sedimentary rock formation just below it (BCOGC 2014)[13].

These differences in experiences again emphasize the importance of recognizing that different unconventional gas plays in North America do vary with respect to their geology, operating

[13] BCOGC (2014). Investigation of Observed Seismicity in the Montney Trend: https://www.bcogc.ca/sites/default/files/documentation/technical-reports/investigation-observed-seismicity-montney-trend.pdf

depths, and corresponding operational practices. In conducting a scientific review of hydraulic fracturing practices and their impacts, it is therefore important to caution that extrapolating experiences from one shale gas play to another might be influenced by case specific differences.

2.5. Current State of BC Regulatory Framework

2.5.1. Regulation and Legislative Background

Hydraulic fracturing in NEBC is an oil and gas activity. The *Oil and Gas Activities Act* (OGAA)[14] is the province's main statute governing oil and gas activities in BC. OGAA and its associated regulations, such as the Drilling and Production Regulation (DPR)[15] and the Environmental Protection and Management Regulation (EPMR)[16], are in place to ensure safe and environmentally responsible resource development and contain the legal requirements for conducting oil and gas activities. This legislation specifies the requirements that must be followed in applying for and conducting oil and gas activities, including hydraulic fracturing. In addition to OGAA and its regulations, there are other statutes and regulations for safety and environmental protection, both federally and provincially, that may apply to some aspect of the life cycle of the hydraulic fracturing process. As well, oil and gas operators must comply with local authority requirements, industry recommended practices (IRP), Canadian Standards Association, labour board laws, and workers compensation rules in order to operate in BC.

The BC Oil and Gas Commission (the Commission or BCOGC also referred to herein) is the single-window regulator agency for the oil and gas industry. The single-window regulator approach centralizes the management of land and water for oil and gas activities into one agency. Under OGAA, the BCOGC has the legislative authority to regulate industry activity and make decisions on permit applications. The BCOGC's specific permitting authority includes the BCOGC's authority to make decisions on certain provisions of legislation that would otherwise be enforced by other ministries and government agencies. These include the *Environmental Management Act* (EMA), *Forest Act, Heritage Conservation Act, Land Act,* and the *Water Sustainability Act* (WSA). As a result of these specified enactments, the BCOGC has authority, for example, to issue authorizations under the WSA, including authorization for changes in and about a stream and short-term water use. BCOGC has additional authorities through designations and delegations from other agencies under a variety of enactments. For example, BCOGC staff are designated by FLNRORD under the WSA as Water Managers and Assistant Water Managers thus providing them authority for issuing water licences. BCOGC has delegated

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[14] Oil and Gas Activities Act (OGAA): http://www.bclaws.ca/civix/document/id/complete/statreg/08036_01

[15] Drilling and Production Regulation (DPR): http://www.bclaws.ca/civix/document/id/complete/statreg/282_2010

[16] Environmental Protection and Management Regulation (EPMR): http://www.bclaws.ca/civix/document/id/complete/statreg/200_2010

authority under the Agricultural Land Commission Act through a delegation agreement and may grant authorizations for non-farm use of lands included in the Agriculture Land Reserve.

The BCOGC provides regulatory oversight at every stage of oil and gas development including: reviewing applications and issuing permits; tracking industry permit holder compliance; conducting inspections and responding to incidents; and exercising compliance and enforcement actions when needed. Regulatory oversight is both comprehensive and complex. The BCOGC also makes use of permit conditions and orders to provide specific technical direction or requirements on how an activity is to be conducted. A list of some of the more significant statutes and regulations that may apply is provided in Appendix C.

2.5.2. Overview of Permitting

Regulatory approvals (permits) from the BCOGC are required to conduct oil and gas resource development activities. Operators must apply for permits to construct and operate an oil or gas well. Hydraulic fracturing occurs during the well completion phase of drilling operations and can last from a few days to several weeks.

Before submitting an application for a well permit, companies are encouraged to conduct required consultation and notification and First Nations engagement. Upon receiving an application, the BCOGC conducts a comprehensive review, which may include engineering, environmental, First Nations, private land owner, or archaeological considerations. Reviews are also done for water authorizations. If approved, activities must be carried out in accordance with the permit, regulations, applicable laws, and timelines and/or conditions that may be attached to the permit. Permit holders may also have operational and reporting requirements such as submitting well reports and well data, and requirements for continued engagement as defined in BCOGC manuals and guidelines.

> *"Once a permit is issued, companies should continue to take into consideration the entire life cycle of the project and minimize the environmental impacts of the proposed project. Permit holders are responsible for keeping current with legislation, regulatory updates and documentation in order to properly and safely pursue oil and gas activities. In addition to manuals and guidelines published on the Commission's website, permit holders should review directives, information bulletins, reports and safety advisories for any changes."*[17]

Construction activities must meet the design and operational requirements outlined in the following regulations and guidelines:

- Oil and Gas Activities Act
- Environmental Protection and Management Regulation

[17] BCOGC Oil & Gas Operations Manual Version 1.22, Nov. 2018, p. 5: https://bcogc.ca/node/13308/download

- Oil and Gas Road Regulation
- Pipeline Regulation and Pipeline Crossing Regulation
- Drilling and Production Regulation
- Geophysical Exploration Regulation

Permit holders should meet guidance recommendations in the following BCOGC documents:

- Environmental Protection and Management Guideline
- Management of Saline Fluid for Hydraulic Fracturing Guideline
- BC Noise Control Best Practices Guideline
- Flaring & Venting Reduction Guideline
- Measurement Guideline for Upstream Oil and Gas Operations

The BCOGC notes on its website "*The successful construction of any well depends upon employing leading standards and best practices in design and drilling processes to provide for operational safety and environmental protection.*"[18]

The BCOGC's guidance and advice also includes Industry Bulletins, Directives, and Advisories which are published on the BCOGC website. Industry Bulletins include industry notifications of process or practice changes, but not changes in regulatory requirements. Directives alert industry of a change in regulatory requirement. Safety and Environmental Advisories provide information of a safety-related practice, process, or observation regarding management of operational activities.

2.5.3. Previous Regulatory Reviews

In 2015, the BCOGC contracted Ernst and Young to review the existing regulatory framework governing hydraulic fracturing in the province (Ernst and Young 2016). Ernst and Young carried out a high-level jurisdictional scan of six jurisdictions based on similar industry maturity and geology. The scan focused on fit-for-purpose opportunities for BC, rather than a direct comparison of regulatory instruments across jurisdictions. Out of scope for that review was comments on or analysis of the scientific, technical, or engineering validity of regulatory instruments or the regulatory framework, the former of which is within the scope of this scientific review.

Overall, the review by Ernst and Young found that hydraulic fracturing was well governed in BC, and that BC is considered a leading jurisdiction in the management of surface water for oil and gas activities. While that review highlighted many opportunities to improve the regulatory

[18] BCOGC Managing Well Integrity: https://www.bcogc.ca/public-zone/managing-well-integrity

system, none of these opportunities were identified as a major failing of the regulatory framework. The Ernst and Young report was reviewed by the Panel and found to be comprehensive. Therefore, the Panel did not duplicate a review of regulations in other jurisdictions. Several recommendations stemming from the regulatory review are likewise recommended in this scientific review.

Similarly, as part of a human health assessment for NEBC ordered by the Minister of Health, Intrinsik Environmental Services found the regulatory system to be broadly protective of human health, although some shortcomings were identified (Intrinsik Environmental Services 2014).

2.5.4. Recent Changes in Legislation

Over the past several years, substantial changes have been made to BC legislation. Notably, the WSA came into force on February 29, 2016. Various Regulations under the WSA were subsequently introduced, along with subsequent amendments. Amendments have also been made to OGAA, with changes most recently made in May 2018. Thus, consideration of the existing regulatory regime by the Panel involved a moving target, which presented significant challenges to the Panel in framing its review of hydraulic fracturing in BC.

2.6. Safety and Risk Management

Risk is defined as the likelihood (or probability) of a hazard threat to cause harm. In the context of natural hazards, threats include natural earthquakes, volcanic eruptions, landslides, asteroid impacts, etc. Each hazard represents a threat that can be characterized by the likelihood of that threat occurring. Vulnerability and, by association, risk is characteristic of the relationship between humans (or the environment, wildlife, etc.) and the natural hazard threat, which takes into account exposure. Thus, if there are no humans, for example, then there is no risk. So, it is important to distinguish the term “risk” from “hazard threat” despite the fact that colloquially it is common to use the term risk rather than hazard threat.

In the context of hydraulic fracturing, hazard threats include unsustainable use of water or use of water in such a fashion as to have a negative impact on the environment; contamination of water to the degree that the water quality has deteriorated; induced seismicity that may cause structural damage to infrastructure or harm to humans and the environment; and fugitive emissions impacting air or groundwater quality and contributing to greenhouse gases and climate change. For each hazard threat, there is a likelihood of occurrence. However, this likelihood of occurrence necessarily must capture not only the likelihood, for example, of a spill occurring but also the likelihood that the contaminated water from the spill will make its way into the environment and pose a threat to an aquifer or stream or indeed to a human, animal, or fish (i.e. receptor). Thus, likelihood is a complex variable to account for and measure, because each step, from spill event through to the receptor carries its own uncertainty and probability.

To assess probability, data are required. Unfortunately, there is a lack of data to enable quantification of probability for all of the hazard threats mentioned above. To illustrate this point, the BCOGC maintains an Incident Map on its public website. This map shows the locations of pipeline incidents that occurred from 2009 to present. It includes data on pipeline spills, releases, and damage to active and discontinued pipelines. Thus, the dataset does not provide information on probability, which would have to be assessed independently for each spill type. Neither does it provide information on whether or not a particular spill or leak resulted in contamination of an aquifer or stream. The potential for a leak or a spill to contaminate an aquifer, for example, depends on the spill size, duration (how much time passed before an intervention took place), how deep the water table is at the location, the permeability of the soils and sediments, the topography, etc. Thus, it is impossible to predict the probability that the aquifer became contaminated and the degree to which it was.

The terms of reference for the Panel indicate that the Panel assess whether BC’s regulatory framework adequately manages for potential risks or impacts to safety and the environment that may result from the practice of hydraulic fracturing, and whether or not BC’s regulatory framework could be improved to better manage safety risks, risk of induced seismicity and potential impacts to water. **Accordingly, the Panel wishes to emphasize that it could not assess risk with any confidence, and therefore, only potential risks are discussed herein. Moreover, the Panel could not assess with confidence whether risk is currently being managed or not.**

Considering the broader implications of shale gas development in NEBC along with other resource development, the Panel considered cumulative impacts in addition to the direct impacts of hydraulic fracturing on human and environmental health and safety. This report ends with a broad discussion on cumulative effects.

3. Water Quantity

3.1. Background

Concerns were raised by representatives who spoke on behalf of Treaty 8 First Nations, environmental consultants, and ENGOs about water quantity (and water quality as discussed in Section 4). According to the representatives who spoke on behalf of Treaty 8 First Nations, "*deep concern*" has been raised by Elders about "*taking water from the near surface and disposing of it deep underground.*" "*This single activity has had profound impact on the spiritual connection between Indigenous people and water*." The Panel notes that Western science too acknowledges that water is central to healthy ecosystems, and that groundwater and surface water are a single connected resource.

The Panel acknowledges that water use management is a very challenging task regardless of the context, largely because the available water changes from year to year due to climate variability (and perhaps longer term climate change). Such variability within a natural system makes it extremely difficult to separate out effects related to natural changes from those due to anthropogenic stressors, such as surface water diversions or groundwater pumping. In most areas, water management decisions are made based on historical data (e.g. average streamflow or average groundwater recharge) which assume stationarity in the system (i.e. that the average streamflow, for example, has remained unchanged over a long period of time), but when historical data do not exist or when the period of record is too short, water use management becomes especially challenging.

NEBC is a vast region, and the need for baseline water quantity (and quality) data became a pressing issue due to the accelerated pace of shale gas development a decade or so ago. In an ideal world, no development would take place unless some background data have been collected. That being said, the BCOGC has made significant efforts to manage water use responsibly in NEBC. Several non-regulatory tools (supported by regulations) have been developed to aid in water management decision making, and while some might argue that these tools fall short, they have been remarkable, particularly given the lack of hydrologic data within the region. This is not to suggest that these tools have been infallible, nor that improvements should not be made.

Accordingly, the Panel considered evidence presented by experts within the rapidly evolving context of hydraulic fracturing in NEBC and recent technological advances. The Panel considered as best possible the history of regulatory and non-regulatory tools for water use decision making (because there have been many changes over the past several years), trying to differentiate what were problems in the past, and whether those problems have persisted. This has been a tall order in the context of water quantity, in particular because of the recent introduction of the Water Sustainability Act (WSA) in 2016 and the accompanying Water

Sustainability Regulation[19] and Groundwater Protection Regulation[20] alongside changes to the Oil and Gas Activities Act (OGAA). At the same time, the statutory decision makers have changed in some cases. As well, there are many non-regulatory requirements that have been introduced over time, as well as industry best practices guidance documents.

This section begins with a discussion of baseline water quantity data. Then, in the subsequent three subsections, threats to water quantity are examined under three main topics: water use; the storage of water on land for use in hydraulic fracturing (i.e. dugouts, dams); and wastewater disposal. Throughout, regulatory requirements or non-regulatory tools specific to the protection of water quantity are reviewed where appropriate. Each subsection ends with recommendations.

3.2. Baseline Water Quantity Data

3.2.1. Concerns Raised

Numerous concerns were raised by representatives who spoke on behalf of Treaty 8 First Nations, environmental consultants, ENGOs, experts from various government ministries, and BCOGC staff about the lack of baseline water quantity data in NEBC. This includes data on streamflow, lake levels, groundwater levels, as well as information on groundwater – surface water interactions, wetlands, and aquifers. There are concerns about the use of water (discussed in Section 3.3) and the potential impacts to water resources in the region that cannot be understood without baseline information and data.

This section focuses on background information on surface water and groundwater quantity information and data. The surface water section includes an overview of climate change and research that has been carried out in NEBC to better understand how the climate has been changing and will continue to change, and the consequent impacts on the hydrological system. This section on climate is specifically linked to the surface water section because the hydrologic modelling focuses solely on streamflow. Discussion of information on Environmental Flow Needs (EFNs) is provided in Section 7.2 in the context of ecosystem health.

3.2.2. Summary of Expert Evidence Presented

Surface Water Information and Data

During the Panel meetings, no expert presented an overview of available surface water quantity data and information. Therefore, much of this review is based on the Panel's independent review of available information.

[19] Water Sustainability Regulation: http://www.bclaws.ca/civix/document/id/complete/statreg/36_2016

[20] Groundwater Protection Regulation: http://www.bclaws.ca/civix/document/id/complete/statreg/39_2016

Several experts commented on various aspects of baseline surface water quantity data. The hydrology expert from BCOGC stated, "*There are a lot of data shortages, especially in smaller basins, and industry is interested in these smaller basins*." It is the understanding of the Panel that industry measures streamflow at some locations, but the Panel was not provided with any details of how many operators carry out baseline streamflow monitoring. One industry operator stated that it had installed 13 hydrometric stations proactively; some of these sites were never used, but data were provided to BCOGC.

The source water protection expert from the Ministry of Forests, Lands, Natural Resource Operations and Rural Development (FLNRORD) stated that there is very little information on lakes. So FLNRORD "*relies on policy with incomplete science (e.g. 10 cm of drawdown as a threshold*)" when issuing permits. This expert also identified large sediment loads in rivers as a concern from the perspective of developing rating curves for streams. He indicated that this is problematic because the sediment accumulates over time and thus changes the stage-discharge relationship. Stage-discharge relationships (or stream rating curves) are critical for converting continuously measured stage data into streamflow estimates. Without an accurate rating curve, it is impossible to obtain an accurate estimate of streamflow.

While the Panel was encouraged to consider traditional knowledge in its review, the representatives who spoke on behalf of Treaty 8 First Nations participated in the Panel Proceedings in a manner that was in keeping with their ways of sharing knowledge and provided the information they wanted to share with the Panel. One member admitted feeling disrespected at being asked to share traditional knowledge. Others indicated a reluctance to share traditional knowledge because of a mistrust of government and a belief that doing so will be used against them. The Panel heard only a few non-specific examples of traditional knowledge related to water quantity. One was the observation of frogs being out of place during a drought. The First Nation contacted BCOGC directly to halt water withdrawals in the area during the drought. A second was that there used to be more wetlands and with this change "*the plants that had medicinal and spiritual meaning no longer grow.*" It was added, "*If these things are violated, the spiritual meaning of the places where these plants grow no longer exists.*"

The climate and hydrology expert from the Pacific Climate Impacts Consortium (PCIC) provided an overview of historical trends in climate and streamflow in the Peace Region. Note: the related report has not yet been released by PCIC. The expert stated that across the Peace Region, there has been a 2 °C increase in temperature over the past century, mostly in the winter. Precipitation trends are less clear, but there are seasonal differences. Summer precipitation has increased, but winter trends are less clear. Climate station density is very low in NEBC – it is the least observed region in BC. Importantly, the cryosphere plays an important role. Based on published studies for the region, ice breakup has occurred earlier in the spring; a decline in snowpack extent and thickness has been observed; permafrost has been warming and disappearing; and there is evidence of the extent of glaciers decreasing in the headwaters of the Peace. Notably, the catchment for glacier melt is largely into the Williston, which is a regulated system; therefore, the expert indicated that management is a key factor. The period of record for streamflow spans several decades and trends are inconsistent across the region and may be influenced by water use.

Future projections of climate change were obtained from the most recent set of CMIP5 (Coupled Model Intercomparison Project Phase 5) general circulation models (GCMs) (PCIC report in preparation). Temperature is expected to increase in summer and winter by approximately 2-3 °C by the end of the century. Precipitation is projected to change very little (or perhaps not at all) in winter, but is projected to decrease during summer. A regime shift from snow to rain is expected, and spring freshet will continue to shift to earlier in the year (Schnorbus et al. 2014; Shresha et al. 2012). The expert stated that this regime shift will cause the summer recession to last longer and summer low flows will be lower. Permafrost area is projected to continue to decline (Bring et al. 2016), ice cover will decrease both in thickness and duration (Dibike et al. 2011), and glacier area and volume will continue to recede (Clarke et al. 2015), leading to less glacier contribution to streamflow (Moore et al. 2009). Overall, there will be a change in the seasonality of water availability.

The expert stated that climate change projections by their very nature are uncertain. However, the projections above are based on the median of ensemble of six GCMs that best capture the spread of future climate conditions for BC. The Panel acknowledges the approach used by PCIC for climate projections is cutting edge. The hydrologic model used for simulating streamflow in the Peace Region (the VIC model), however, has limitations: 1) groundwater is not represented; 2) the version of the VIC model used to simulate streamflow also does not include glaciers (although the most recent version does); and 3) the VIC model does not include permafrost. A key challenge expressed by the expert from PCIC includes the need for more data to develop a better understanding of hydrological linkages (e.g. the role of groundwater and the anticipated regime shift). Other challenges, specific to water management in NEBC, are discussed in Section 3.3.

Groundwater Information and Data

The provincial government operates seven observation wells in NEBC at which hourly groundwater level and water temperature data are recorded. The groundwater level data are reviewed and corrected against water levels measured with a standard water level tape twice yearly to assure the digital data are representative (i.e. to correct for drift in the measurements). Six of these wells are completed in bedrock and one in unconsolidated sediments. Five of the wells (#416, #417, #418, #419, #445-replacing #421) have only been monitoring since 2012-2014, and one of these is flowing and provides no water level data. Only one bedrock well (#124 Charlie Lake) has a period of record back to 1971, and the well in unconsolidated materials (#286 Tumbler Ridge) has been monitored since 1989. Pumping tests were conducted in all wells to obtain estimates of the transmissivity of the aquifers prior to beginning monitoring. Transmissivity is one parameter needed to assess how an aquifer responds to stresses (such as pumping). Access to these wells is possible for other studies (e.g. for the McGill study on induced seismicity), and data are publicly available online.

Based on evidence presented to the Panel, groundwater levels are variable in all records, with peaks occurring generally in summer due to snowmelt. In well #420, the deepest well, groundwater levels peak in winter because of the lag in response time due to its greater depth. BC government hydrogeologists have analyzed the groundwater level data for trends, although whether the trends are statistically significant was not discussed by the government expert who addressed the Panel. The groundwater level records show variability from year to year, as might be expected due to variations in climate. However, in #286, there has been a notably visible decline in groundwater level by approximately 6 m since 1998, while prior to 1998 there was no clear trend. In well #124, groundwater levels declined by approximately 1 m during the period ~1986 to ~2002, but rose again and have remained stable since. No explanation of this unusual response was given by the expert. The Panel notes that these variable responses point to the complexity of groundwater level responses in a handful of hydrogeological settings and uncertainties in what the responses actually mean.

In 2011, the BC government initiated the NEBC aquifer characterization project (Dawson Creek – Groundbirch) with the main goal of characterizing aquifers in the region (Baye et al. 2016). The Private Wells Survey, a key component of this study, focused on groundwater chemistry (discussed in Section 4.2). A dataset of well records was compiled from different sources, and interpreted using standardized lithologic descriptions to identify the major hydrostratigraphic units in the study area. Four two-dimensional geological cross sections were constructed. Geophysical data were also used to support the hydrostratigraphic interpretation. Weathered and fractured sedimentary rocks underlie unconsolidated sediments throughout much of the study area. In parts of the study area, aquifers are mapped as moderately or lightly developed bedrock or unconsolidated aquifers as per the provincial aquifer classification scheme. Measured groundwater level elevations generally mimic topography, with upland areas appearing to be local recharge areas and low lying areas and river valleys appearing to be local discharge areas. Recharge modelling estimated groundwater recharge to vary spatially from 2-68 mm/year. Average annual precipitation is approximately 450 mm/year, therefore, recharge is approximately 0.4-15% of precipitation. Water levels in deeper bedrock wells are generally stable throughout the year, while shallower bedrock wells exhibit small increases in groundwater levels following the freshet. These observations are consistent with low aquifer conductivity values measured in pumping tests, and low recharge estimates controlled by the presence of overburden deposits of till and glaciolacustrine sediments.

3.2.3. Other Evidence Considered

The BCOGC maintains a Water Portal[21] that is a map-based water information tool designed to provide public access to a wide range of water-related data and information in NEBC. Within the Water Portal, users can filter results by Network to view water quantity and quality data for each of surface water and groundwater stations. In NEBC, the Networks include Geoscience BC, the BC Oil and Gas Industry, the University of Northern British Columbia (UNBC), and Water Survey of Canada (WSC). Considering all Networks, there are roughly 95 stations in NEBC, but only ~29 are currently active and all but one is operated by Environment and Climate Change Canada (ECCC). For groundwater quantity, there are seven wells currently being monitored (these are the Provincial Observation Wells). [At the time of writing this report, the link to the Portal was not easily found in the Public Zone. This Portal is located under Water Information, but there is a side menu item “Water Licences” that takes the user to the Water Licences webpage. The link to the actual Water Portal should be made more evident.

The Horn River Basin Water Monitoring Study was undertaken by Kerr Wood Leidal Associates in partnership with First Nations and Peace County Technical Services over the period 2012-2015 (Kerr Wood Leidal 2016). The primary goal of the baseline monitoring program was to characterize surface water and collect water flow data while engaging and training First Nations to allow for sustainable planning and use of water for shale gas development. Three climate stations and seven hydrometric stations were installed. Real time climate and hydrometric data were collected and made available on FlowWorks[22]. However, it appears that the most recent data are from 2016.

Between 2004 and 2011, a hydrogeological study was carried out to identify, delineate, and classify aquifers in the Peace Region as part of Geoscience BC’s Montney Project (Lowen 2011). In 2004, 40 aquifers were mapped, covering a total area of 3,413.7 km^2. These aquifers were reviewed in 2011 with revision of statistics for 38 of the 40 aquifers, revised boundaries for 21 of the 40 aquifers, and the mapping of 16 new aquifers. As of 2011, a total of 551 aquifers had been mapped in the Peace River Region, covering an extent of 10,491.5 km^2. A second groundwater resources assessment was carried out in the Liard and Petitot sub-basins (Levson et al. 2018). A total of 6,418 discrete aquifers were mapped comprising almost 3,000 km^2, but only 5.7% of the entire study region (51,217 km^2). Aquifers mapped using surficial geology data in the area consist of alluvial (mainly fluvial) aquifers (57.3% of all aquifers mapped), with a high potential for hydraulic connectivity with streams, and upland (mainly glaciofluvial) aquifers (42.7%) that may or may not be hydraulically connected to streams. A total of only 208 water well records were obtained for the area; 27% (56 wells) are in surficial aquifers and 33% are in bedrock aquifers (68 wells). The aquifer type is unknown for 32% (66 wells) and 9% were dry (18 wells). The study concludes that there are very few data on the hydraulic properties of

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[21] BCOGC Water Portal: http://waterportal.geoweb.bcogc.ca/

[22] FlowWorks: http://www.flowworks.com/network/index.aspx

aquifers that can be used to assess the impacts of pumping and the long-term sustainability of the aquifers. Basic information such as the volume of storage available for each aquifer is not known. The Panel examined the provincial Geographic Information System (GIS) mapping system, iMapBC[23], but could not locate the aquifer polygons referred to above.

Several studies related to groundwater quantity were carried out north of the Peace River by Geoscience BC and various partners as part of the Peace Project (summarized by Morgan and Allen 2018). The studies included conducting an airborne electromagnetic (EM) survey (using SkyTEM); analyzing natural gamma logs from shallow intervals in industry wells; drilling boreholes at eight locations to verify the interpretation of the geophysical data; determining the petrophysical characteristics, and constructing 2D and 3D geological and hydrogeological models; investigating through numerical groundwater flow modelling the role of buried valley aquifer systems in the regional hydrogeology; and identifying potential aquifers that may provide groundwater supplies for First Nations. Geoscience BC collaborated with Treaty 8 First Nations to add Blueberry extension, Doig, and Charlie Lake blocks for EM survey. The Quaternary sediments of the Peace Region are interpreted to be lithologically heterogeneous across all scales of investigation, and the thickness of the Quaternary sediments is variable; however, the Quaternary fill is generally thick within the outlines of the mapped buried valleys. Permeable deposits are interpreted to exist within the buried valleys, although they were not found to be regionally continuous throughout the whole buried valley network. Nevertheless, locally extensive permeable deposits within the buried valleys appear to exist at smaller scales. Therefore, these localized buried valley aquifers may offer a viable groundwater source for low demand users. Bedrock aquifer potential was not explored, and was recommended for further investigation.

Aquifer Stress mapping was carried out across BC (Forstner et al. 2018) using the groundwater footprint approach (Gleeson and Wada 2013). This involved estimating recharge for unconfined aquifers (confined aquifers were not considered in the study), estimating the volume of groundwater used, and determining the amount of groundwater that discharges from the aquifer to streams.

Finally, through the Northeast Water Strategy (NEWS), there has been an attempt to coordinate projects and identify knowledge gaps related to baseline information and data. The Groundwater Knowledge Steering Committee under NEWS was begun in 2015 specifically to guide development of sufficient and appropriate groundwater knowledge to effectively inform decision making related to the sustainable management of groundwater resources in NEBC. Unfortunately, this initiative lost momentum at an early stage, but has recently held a few meetings via teleconference.

[23] iMap BC: https://maps.gov.bc.ca/ess/hm/imap4m/

3.2.4. Key Findings

Considering the vastness of the region, alongside the increased level of industrial development, the Panel considers the baseline data and the ongoing monitoring of surface water and groundwater quantity to be insufficient.

Baseline data and information on streamflow, lake levels, and wetlands are sorely lacking, particularly given the high demand for surface water for industrial use (as discussed in Section 3.3). The groundwater level data from the Provincial Observation Well Network are insufficient to determine trends, particularly in the newer records (those since 2012). Moreover, the observation wells are very sparsely distributed (currently seven across the entire Peace Region), and while there has been an effort on the part of government to install new monitoring wells in the region, the current coverage is insufficient, particularly given the diverse hydrogeological settings (bedrock and unconsolidated aquifers, unconfined and confined aquifers), and the extensive footprint of hydraulic fracturing activities. Two new wells will be drilled in summer 2019 in the Fort Nelson area; however, the hydrogeology expert from ENV acknowledged that maintenance of wells is particularly challenging in remote areas.

Basic information on aquifers has not been collected in most areas, with notable exceptions in the Liard and Petitot sub-basins, the Dawson Creek – Groundbirch area, and the area to the northeast of Fort St. John (the Peace Project area). To date, there has been insufficient characterization of bedrock aquifers. In general, there is a lack of data on aquifer properties, which are the only means to assess aquifer sustainability. First Nations are being asked to provide input on applications for industry source wells; however, they do not receive any information on the aquifer, only the proposed well location.

Finally, to the Panel's knowledge, no comprehensive studies have been carried out on interactions between groundwater and surface water, and neither on wetlands. First Nations are provided little, if any, information on the potential connection between the aquifer and any nearby streams. As a result, they feel they cannot adequately evaluate proposals.

3.2.5. Recommendations

Lapp et al. (2015) conducted an information needs assessment by surveying key people involved in water research and management in NEBC. In total, 65 respondents completed the survey and identified priority topics for research, monitoring, tools, and policy. Priority research needs consistently identified by respondents included the following:

- Water balance research that quantifies fluxes (e.g. evapotranspiration, recharge) and storage (e.g. groundwater, lakes, wetlands) for the range of landscapes and land cover types (e.g. wetlands, upland forests, ponds) present in NEBC. Due to differences in physiography and climate between the northeast and other regions of BC, knowledge gained from long-term watershed research in other areas may not be directly transferrable;

- Aquifer identification and characterization to quantify the availability and extent of groundwater resources;
- Climate change effects on all aspects of water resources, aquatic ecology, and natural hazards; and
- Development of methods for quantifying cumulative effects of resource development and land use change on water quantity and quality.

Most respondents of the survey, as well as experts interviewed by the Panel, identified the need for baseline monitoring of surface and groundwater quantity and quality along with climate data. Currently, the lack of data is seen as an impediment to sustainable water management in NEBC. The low spatial density of monitoring sites and short temporal records make the development and testing of predictive models (e.g. streamflow, water quality) difficult. Baseline monitoring is necessary for detecting trends and setting guidelines and thresholds for identifying resource development–related impacts.

Many respondents of the survey also identified the need to make monitoring and research data and results easily accessible to water managers and industry. The need for consistent, mandatory data collection, archiving, and dissemination was also strongly recommended.

Ernst and Young (2016) recommended the following:

- Specific data collection and submission requirements related to the characterization of shallow aquifers in NEBC would allow for more informed decisions related to the isolation of porous zones containing usable groundwater and determinations for the base of all porous zones containing usable groundwater.
- Guidance on the criteria or methodology for identifying porous zones containing useable groundwater would provide consistency with respect to interpretations by qualified professionals.

The Ministry of Health study on risk to human health (discussed in Section 7.1) made two recommendations related to water quantity (Intrinsik Environmental Sciences 2014):

- Existing aquifer mapping should be expanded for NEBC to help enhance the protection of groundwater resources in relation to oil and gas development.
- Additional study of groundwater and surface water interactions with shallow aquifers and local groundwater flow conditions should be completed in NEBC.

The collection of baseline data and information should include local traditional Indigenous knowledge. Working toward a shared understanding of the climate and hydrological linkages in

NEBC would be of huge benefit to resource management. However, information sharing will require trust. The Panel is highly supportive of any efforts to build trust between First Nations, government, and researchers so that we can mutually benefit from each other's learnings.

Finally, most of the research to date has been focused on the area around Fort St. John, and knowledge may not be transferrable to more northerly regions with discontinuous permafrost. Therefore, baseline studies should also target these northern regions.

3.3. Water Use

3.3.1. Concerns Raised

Water use was perhaps the most significant concern raised during the Panel Proceedings. Representatives who spoke on behalf of Treaty 8 First Nations expressed significant concern about the large quantities of what was "*originally fresh water being removed from the surface environment and being disposed of underground*." In their view, "*these abuses of water* - using large volumes of water and disposing of it - *are wounds.*" The representatives stated that Treaty 8 First Nations "*do not like seeing water used in this way and being disposed of because it violates the spirit of their relationship with water*." The representatives who spoke on behalf of Treaty 8 First Nations stated, "*if deep saline water is unusable as a potable water supply, then it should be used for hydraulic fracturing rather than fresh water.*" They also stated, "*Companies are asking to take water for 40 years, but the company has plans for recycling, so why is a 40-year licence needed*?"

Concerns were also expressed regarding water permitting, specifically in relation to the regulatory and non-regulatory tools used to support water allocation decision making. In reference to the Northeast Water Tool (NEWT), one representative who spoke on behalf of Treaty 8 First Nations stated they were "*appalled that a desktop tool is being used for the first time in any jurisdiction to manage water at the headwaters for major river systems in Canada*." Concerns were expressed about the seasonality of streamflow in relation to summer low flows, especially during drought conditions, which need to be maintained to support EFNs. Concern was expressed that NEWT modelled volumes are not considered accurate during drought conditions; and there are no measurements.

Also in relation to permitting, the representatives who spoke on behalf of Treaty 8 First Nations indicated that water use applications were (up until 3 years ago) handled by FLNRORD, but more recently, "*there have been larger and larger water use systems (water withdrawal and water transportation) that have been having an impact on First Nations Treaty Rights*." "*Industry is taking water from key areas or applying to use water in these key areas*." One First Nation has been trying to encourage companies not to withdraw upstream on the Halfway River, but stated that this has been a "*losing battle*." The representatives stated that First Nations review applications, and can stipulate conditions, but that these conditions do not get incorporated into the approval conditions for the licence. One First Nation received applications for review from two companies within two days for a total of 7,000,000 m^3 water. These were separate applications, but they happened to come across the First Nation's approval desk together. Because of this, they feel that water applications are being considered in isolation from one another and that there should be a cumulative effects approach to the application process. The representatives also indicted that there is also a short turn-around time for the approval process, which limits their ability to consider applications. At the time of the Panel Proceedings, one First Nation had a referral for a water pipeline on their desk, but insufficient information was provided in the referral to judge potential impact during drought times.

The use of dugouts for water storage was highlighted as a particular concern (note: large water retention structures or dams are discussed separately in Section 3.4), and in relation to this, the sale of water from private landowners to industry. Concern was expressed about groundwater use by industry and the potential for an increase in use in future. Finally, ministry staff expressed concerns about gaps in policy and/or regulation.

This section focuses on historic and current water use in NEBC, primarily industrial water use, the regulatory and non-regulatory tools used to manage water, and how industry is responding through recycling and reuse of wastewater to lower its freshwater footprint. This section does not speak to dams, which are discussed separately in Section 3.4, because these large structures have raised sufficient concern to merit separate review by the Panel.

3.3.2. Summary of Expert Evidence Presented

Industrial Surface Water Use

Water used for oil and gas activities (including hydraulic fracturing) is obtained from a variety of sources and increasingly makes use of recycled water from flowback water, produced reservoir fluids, grey water from the City of Dawson Creek and, to a limited extent, groundwater (discussed below).

At the time of the Panel Proceedings, the BCOGC hydrology expert had only recently been hired to the position. Understandably, the expert's familiarity with BCOGC's history in water management was somewhat limited. The expert gave an overview of the regulatory and non-regulatory tools that are used to support water use decision making in NEBC. BCOGC is also involved and has input in three provincial initiatives: the Technical Drought Working Group, the Water Policy and Legislation Committee, and the Provincial Water Working Group.

The BCOGC regulates water use under both the WSA and OGAA. Access to water can be obtained through either a water licence (Section 9 of the WSA) or water use approval (Section 10 of the WSA - previously Section 8 or short-term approvals under the *Water Act*). A water licence is commonly used as authority to access water for activities exceeding a two-year period. These activities include such purposes as well drilling and well completions over a number of years in a lease area, road maintenance or winter access requirements, or where a permanent water infrastructure (e.g. a pipeline) is used as part of a water supply strategy. When issued, a water licence provides rights to long-term water access through the “first in time, first in right” (FITFIR) principle of the WSA. Water licences associated with oil and gas or related activities are issued with terms of 5 to 20 years. Water licence applications require the submission of a water management plan that includes detailed information on the water supply, the quantities of water required for specific purposes (per day and per year, and specific dates), how much water is currently allocated upstream (licences and use approvals), details on the construction and operational activities (water intakes, pipelines, storage), supporting technical information on EFN assessment, NEWT results with additional supporting hydrometric data and modelling, and documentation of any issues that may exist with respect to First Nations rights or for individuals or groups that may be affected by the issuance of a licence.

Short-term water use approvals are for a maximum of 2-years duration and may be from a stream, river, lake or dugout. These have the same general requirements as for a licence, with the notable exception that NEWT alone can be used (in some cases additional information is required). A water Supply/Demand analysis is required for any short-term use application when a river or lake source contains a single point-of-diversion greater than 200 m^3, or greater than 10,000 m^3 in total, or any water source dugout with diversion greater than 10,000 m^3 total with a reasonable likelihood of hydraulic connection to a proximal stream (including a swamp, marsh or fen). This water Supply/Demand analysis must include an EFN discussion. Within short-term use approvals, BCOGC can issue a suspension on water use during times of drought. In some cases, First Nations have alerted BCOGC to operators continuing to take water during periods of suspension.

The Provincial EFN Policy (amendment no. 2, effective February 29, 2016) states that in situations where a water allocation decision will significantly impact on EFNs, the comptroller or water manager may refuse the application or specify conditions for water use. The policy describes a coarse screening tool for statutory decision makers for assessing the risk to EFNs in the review of applications for a water licence or a use approval for short-term water use where the origin of water is a river or creek (or an aquifer reasonably likely to be hydraulically connected to a river or creek). The policy is not a method for determining EFNs, but rather is a framework for assessing risk and identifying where cautionary measures could be taken or additional analysis may be needed, including developing site-specific EFN thresholds.

In relation to EFNs, BCOGC allocates up to a maximum of 15% each of monthly and annual mean discharge (note that BCOGC stated it has never allocated the maximum amount allowed). BCOGC also has various thresholds for water use (zero withdrawal). Different methods are used to assess thresholds: 20% of mean annual discharge; 7-day average flow that occurs 1:10 years; 1:10 monthly flows. Some companies use the “Desk-top Method for Establishing Environmental Flows in Alberta Rivers and Streams” approach that considers either 15% instantaneous reduction from natural flow, or the lesser of either the natural flow or the 80% exceedance natural flow. The EFN policy is being re-examined by BCOGC in the Blueberry watershed through a pilot project to specifically consider the flow needs for specific fish species.

The various guidance documents made available to industry (e.g. Short Term Use Approval Manual, and Water Licence Manual) are currently being updated. These documents, and the thresholds cited within them, are being re-evaluated.

When allocating water, BCOGC picks a worst case scenario for setting conditions, i.e. they assume the company could take all the water in one month (a conservative approach) rather than over the full term of the licence, but daily limits are imposed. [As a side note, according to the hydrology expert, these various limits are recorded in a spreadsheet. The Panel questions whether a spreadsheet is an appropriate tool for keeping track of water use.] The hydrology expert from BCOGC also indicated that in NEWT, irrigation licences are assumed to consume more water than they actually do, meaning less water is assumed to be available for oil and gas use than is actually the case.

Water allocation restrictions can be imposed by BCOGC and there are now clear directions to industry on when they can use / not use water. Two systems are under water allocation restrictions. Kiskatinaw River (possible water shortage) and Pouce Coupe River (fully recorded). Draft policy is being developed by BCOGC on zero withdrawal thresholds.

Non-regulatory tools used by the BCOGC in water allocation decision making include: NEWT, data included in the Water Portal (Water Survey of Canada hydrometric data, water quality data and climate data), FLNRORD snow survey data and information from the River Forecast Centre, hydrometric data collected by industry, the Water Licence Query Tool, and hydrological modelling conducted by companies. The NEWT and its limitations are described in detail in Section 3.3.3 below, and the Water Portal was discussed previously in Section 3.2.3. The BCOGC hydrology expert acknowledged that there is limited climate, snow survey, and hydrometric data in NEBC, particularly for small basins.

Water volumes used in oil and gas activities are required to be reported directly to the BCOGC on a quarterly basis, and the BCOGC issues quarterly "Oil and Gas Water Management Summaries." BCOGC routinely shows a graphic (as it did to the Panel; Figure 7) that shows authorized annual water use in NEBC at roughly 0.03% of the average annual volume. Reported annual water use is a fraction of this amount at roughly 0.004%. However, this graphic is misleading because the vast majority of runoff occurs during the freshet and so the estimates appear low. Yet, water is being taken year round and should more appropriately be reported as seasonal (or monthly) percentages of runoff.

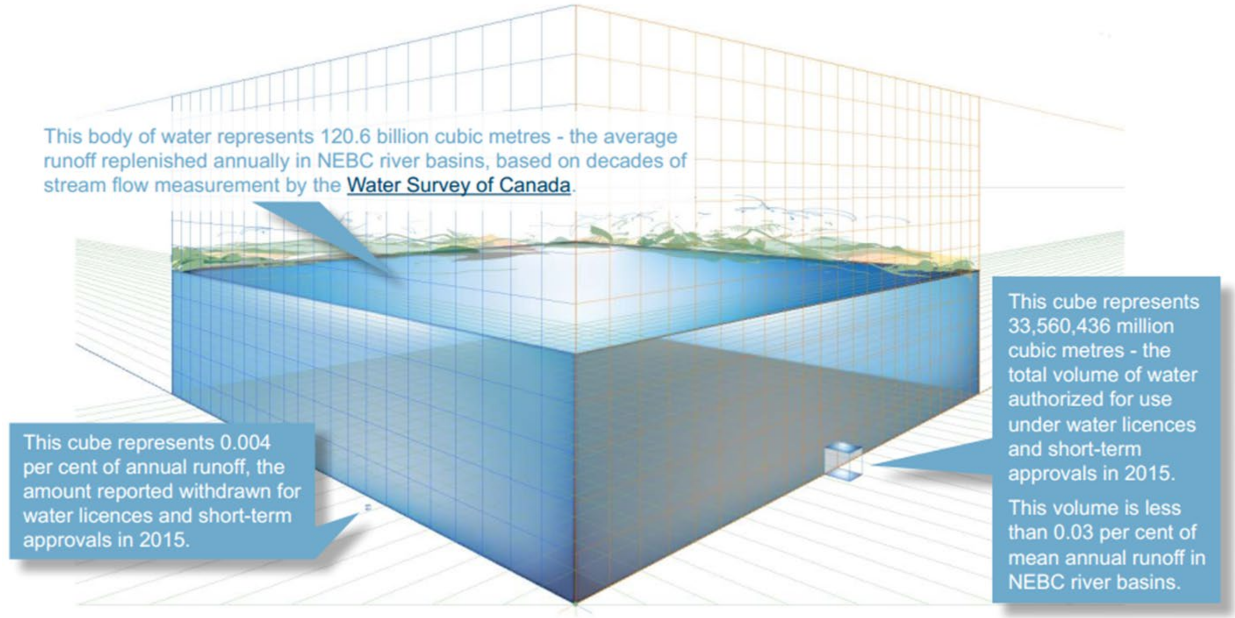

Figure 7. Comparison of annual runoff, water allocation and volumes reported withdrawn in 2015. Source: BCOGC.

The BCOGC reported to the Panel that companies tend to use 5-10% (on average) of what they have been allocated. Water use data (for water licences and use approvals) were provided to the Panel by BCOGC for 2012 to 2017. Notably, water use decreased substantially in 2016 as industry operators introduced technological advancements allowing them to make use of recycled water from produced and flowback water. However, water use reported by BCOGC does not include water use by private landowners that may be sold to industry. This could potentially be a large volume of water that is not being accounted for by BCOGC in water use reporting.

Because FLNRORD also allocates water under the WSA, the Panel was interested in the perspective of FLNRORD staff. The expert stated that when FLNRORD allocates water, it is necessary to assure EFNs are being met. He indicated that previously this was done on "*gut instinct*" on the part of the decision maker, but now EFNs are more formally assessed, and that prior to the WSA, no one ever considered instantaneous water flow, just an annual amount. The expert stated that NEWT provides a good estimate of mean annual discharge (MAD), and MAD is a primary metric for evaluating EFNs (expressed as % MAD), but since the WSA came into force, consideration is now given to instantaneous (and spatial) water availability, which is not as easily assessed. The FLNRORD expert stated that there are few active hydrometric stations in NEBC: 30 are operated by Water Survey of Canada and 1 by industry (Black Swan Tommy Lake). He stated that small streams are not adequately represented in NEWT, and the size of the watershed is not really an indicator (some streams can go dry while others streams continue to flow); seasonal differences in watersheds are also not well understood; and NEBC is a broad region, with diverse hydrology. As mentioned in Section 3.2, there is very little information on lakes. So the expert from FLNRORD stated that decision makers rely on policy with "*incomplete science*" for permitting (e.g. 10 cm of drawdown as a threshold), and while there has been some attempt to develop EFN policy for lakes, *"this never got anywhere*." Finally, the expert stated that FLNRORD does not really know when and how much water people are actually using.

Industrial Groundwater Use

At present, groundwater use by industry is a small percentage of the total water used for hydraulic fracturing. According to BCOGC's Water Management for Oil and Gas Activity 2015 Annual Report[24] groundwater use from source wells accounts for 1.8% of total industrial water use. However, a graph presented by BCOGC during the Panel Proceedings indicates that 1.7% of all water use is from deep source wells, and 1.4% from shallow source wells. Thus, the total groundwater use appears to be on the order of 2-3% of total water use. The hydrogeology expert from BCOGC indicated that "*uncertainty in groundwater availability, and in some areas incompatible shallow groundwater chemistry, do not suggest significant increases in groundwater use are imminent/likely, as evidenced by new water source well application rates (~1-3 per year)*."

All water source wells require a well permit under OGAA and a water authorization under the WSA, unless the source wells are "deep", defined as being below the "Base of Usable Groundwater." Unlike other jurisdictions that set arbitrary depths above which oil and gas activities cannot be carried out, BC has, in the view of the Panel, adopted a more robust means to define "deep groundwater" so as to distinguish it from the shallow groundwater zone (the zone of usable groundwater). Under the WSA, deep groundwater is defined as groundwater at a depth greater than 600 m below the surface, or groundwater below the base of the fish scales marker or an identified older geological marker at least 300 m below surface. The "base of fish scales marker" is a regional stratigraphic marker within the Western Canadian Sedimentary Basin that demarcates the boundary between the sedimentary rocks of the Lower Cretaceous Age from those of the Upper Cretaceous Age, which coincide with beds of thick shales (Figure 8). The boundary is thus hydrogeologically defined and aims to assure that oil and gas activities are adequately separated from shallow groundwater (Industry Bulletin 2016-09)[25].

[24] Water Management for Oil and Gas Activity 2015 Annual Report: https://www.bcogc.ca/node/13261/download

[25] INDB 2016-09: https://www.bcogc.ca/indb-2016-09-technical-guidance-determining-base-usable-groundwater

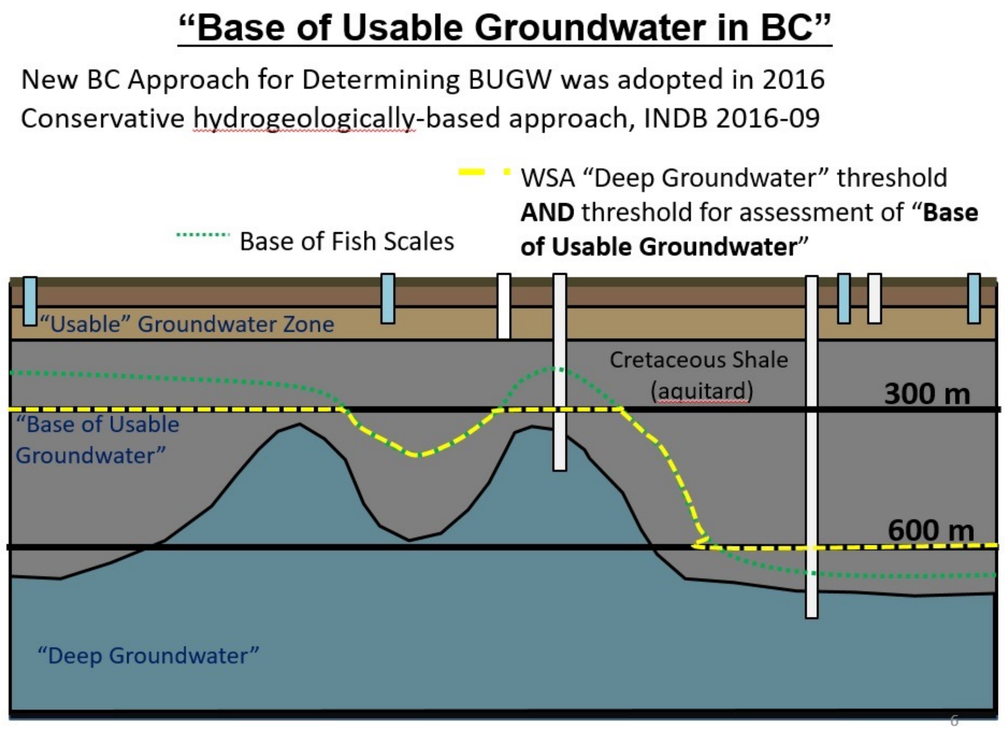

Figure 8. Base of Usable Groundwater (yellow dashed line) shown in relation to the Base of Fish Scales Marker (green dotted line). Under the WSA, deep groundwater is defined to occur at a depth exceeding 600 m or below the base of fish scales marker at least 300 m below the Earth's surface. Source: BCOGC.

Deep source wells are only regulated under OGAA. BCOGC is responsible for the authorization and regulation of all water source wells. The requirement for a licence to use groundwater represents a significant change to the licensing process. As of 2016, non-domestic groundwater is now licensed under the WSA. Under the WSA, for a new licence, the applicant needs to assure: 1) the water extraction is sustainable by conducting a pumping test; 2) the water extraction will not significantly impact the existing groundwater use through analysis of pumping test data; and 3) the water extraction will not compromise the EFNs if the well is connected to a surface water body. In addition to the water use volume, information such as detailed well log, hydraulic properties obtained through the pumping test, a hydraulic connectivity assessment, and long-term monitoring data are collected and submitted as part of the application. [The Panel notes that water source wells, and water source well projects or facilities, pumping at rates greater than or equal to 75 L/s may be reviewable projects under the BC Reviewable Projects Regulation and thus subject to additional requirements under the *Environmental Assessment Act*.]

The hydrogeology expert from ENV provided the Panel with examples of groundwater use licence applications. In these examples, the expert used 10% of recharge as an estimate of the amount of water that could be taken, although no justification for this number was given. Using an estimate of total recharge (estimated at 15% of precipitation) and the aquifer area, a decision on the licence is made. Two out of three example applications shown were from private well owners for sale to oil and gas operators (the expert indicated there were many more such applications). Use volume is 50,000 m^3/year and above. These applications are not specific to oil and gas operators and so do not fall under OGAA, they only fall under the WSA. The hydrogeologist from ENV did not know if BCOGC has different requirements for licensing of source wells. This topic is explored further in Section 3.3.3.

The hydrogeology expert from ENV stated that the challenge with licensing to date is that processing of licences under the WSA has been slow. He also reported that the quality of the technical assessment reports is variable, and a few are of low quality. In addition, because the major water source in the region is from fractured bedrock, a limited duration pumping test and analysis (required for a licence application) may not be sufficient to evaluate the sustainability of the aquifer. The expert suggested that long-term monitoring plans are needed for use of groundwater from bedrock.

Industrial Dugout Use

Dugouts, or artificial ponds, have become a common feature on the landscape in NEBC. Traditionally, dugouts were used primarily as a water source for livestock, but in recent years they have been used for oil and gas activities. Some of constructed water features are, in reality, dams and are discussed separately in Section 3.4, as they are a particular concern.

In 2016, FLNRORD initiated two projects to: 1) identify constructed water storage structures using satellite imagery, and 2) to explore the legal, policy, and practical challenges of addressing concerns about dugouts (Mattison 2017; see FLNRORD Fact Sheet, December 2017 regarding the key findings of that study). The satellite image analysis found approximately 8,000 constructed water storage structures (larger than ~400 m^2) in the Northeast Region [Note: three small regions to the east along the BC-Alberta border and along the southern and southwestern edge of the Peace Region, and one large region in the northwestern part of the Peace Region had no satellite data]. Four classes of constructed water feature were identified: agricultural, municipal, borrow pits for exploration purposes, and oil and gas. Approximately 53.6% were classified as small features (≤0.04 to <0.1 ha), 39.9% as medium (≤0.1 to <0.5 ha), 4.5% as large (≤0.5 to 1.0 ha), and 1.9% as very large (≥1.0 ha). Approximately 500 of these features were estimated to be larger than 0.5 ha (5,000 m^2). The expert acknowledged that features smaller than 40 by 40 m were too small to be resolved, so features smaller than this may have been missed. The depth of the feature also could not be determined, thus no estimate of volume was possible. Oil and gas related features ranged in size from 0.04 to 8.0 ha with a mean size of 0.4 ha. The density of these features was largest in the Lower Beatton River, Pouce Coupe River, Lower Kiskatinaw River, Lower Peace River, and Blueberry River watersheds. FLNRORD has since undertaken a similar analysis using 2017 satellite imagery; the

Panel saw preliminary results of this analysis. A total of 585 features were identified in the gap regions of the 2016 study, and a total of 148 features were considered new construction in 2017 (110 of these related to oil and gas). In summary, as of the 2017 survey, there was a total of 8,729 constructed water features, 1,411 of which were interpreted to be related to oil and gas activities. The construction of oil and gas features > 1 ha in size rapidly accelerated around 2008 and was ongoing in 2017 with 15 new > 1 ha features. These statistics derive from a presentation made by an expert from FLNRORD along with the supporting documentation (Bevington 2017).

In addition to the remote sensing analysis undertaken by FLNRORD, the BCOGC completed a desktop GIS exercise that reviewed 640 water bodies using high resolution orthophoto imagery and the results of FLNRORD's constructed water impoundment analysis. The results of this exercise were summarized by the expert from FLNRORD. Of the 512 large and very large dugouts (waterbodies in excess of 0.5 ha in size and identified in FLNRORD's review), 434 were reviewed, including 268 that were deemed to be oil and gas related (as they are proximal to oil and gas infrastructure) and 166 that were associated with resource roads. In addition, 206 medium sized dugouts were included in the review as they could be readily addressed in conjunction with the larger dugouts. The GIS and orthophoto review determined that 583 of the 640 water bodies do not have dams. These sites include borrow pits, sumps, produced water ponds, and lease water runoff ponds.

Industrial Recycling and Reuse of Water

According to industry operators, water source selection for oil and gas activities can be highly complex with multiple variables, including: distance to the water source, storage, access, water chemistry, proximity to residents, volumes, availability/timing, environmental factors, and cost. Each operational area requires a tailored approach, and the various project stages of development also correlate directly to water source options (e.g. exploration phase, evaluation phase, and development phase each have different water needs). Water management is complex and includes many considerations such as water resource uses, stakeholders, new regulations, and operational needs. The larger operators have in-house Water Management Groups that consider the full life cycle of water. One of the large industry operators has found the transition to the WSA challenging, although stating that the government's approach has been reasonably clear and responsible.

The BCOGC, provincial ministry staff, and several industry operators interviewed by the Panel indicate that freshwater use has decreased in recent years. One operator showed significant declines in freshwater use in 2016 and 2017. The ENV expert on waste management indicated that approximately 40% of produced water is reused. This reduction may in part be due to a decreased level of activity in NEBC, but can also be attributed to an increase in recycling and reuse of flowback and produced water, particularly by the larger operators. It was explained to the Panel that only 4 years ago, chemical incompatibilities prevented the reuse of flowback water for hydraulic fracturing purposes. However, research advances in friction reducers have since opened up the ability to use saline waters as a fracturing fluid, presenting a technical opportunity to reduce fresh water use. One operator blends their produced saline water with fresh water at a major water hub (Figure 9). This was reported to be running at 55% produced water and 45% fresh water. Another large operator reported that it recycles between 90-95% of water; in 2017, 92% of water was recycled, and at present there is an excess of produced water available based on projected growth in operations.

Figure 9. Industry water hub where hydraulic fracturing water is recycled and reused. Photo taken during the Panel's site visit.

Industry operators are collaborating more (e.g. through the Montney Water Users Group) to share water; although one operator stated that it is sometimes difficult to determine how to get water to other operators. In the last year, one large operator shared over 300,000 m^3 of produced water. The operator stated that they had built over 500 km of pipelines to connect storage ponds to other storage ponds and to new leases. During gas pipeline construction, they also construct a produced water and freshwater line to the location, which allows them to realize cost savings not only during the construction phase but on the completions costs for providing water to location. Bi-directional pipelines allow them to safely and efficiently move water throughout their system and support their goal of 100% water reuse. The operator indicated that this system has allowed them to reduce truck trips by more than 255,000 over the last 5 years, resulting in several added benefits: lower emissions and noise, less road maintenance, and most importantly, decreased risk of spills and accidents. The operator has a thorough pipeline integrity program to mitigate corrosion and leaks that help prevent spills. To prevent stagnant saline water from sitting in the pipelines, they flush the lines with fresh water after a fluid transfer has been completed. As activity changes, these pipelines are also used to balance ponds between areas so they maintain the right fluid volumes where they are needed. In summary, the larger operators are making an effort to conserve fresh water, and claim to only use fresh water when there is a shortfall in available recycled water. This reduction in freshwater use also has the benefit of reducing the amount of disposed wastewater.

Municipal Water Use

Some municipal water is used by industry, and so municipal water use is discussed here.

The City of Dawson Creek has been the longest licence holder on the Kiskatinaw River. Currently, four reservoirs are used for storage with approximately 540 days of water storage available. Due to the high sediment load of the Kiskatinaw River during freshet, the city relies solely on stored water. The water is treated prior to use, and it takes approximately 3 months for water to get from the river to the end of treatment. The city has been metered since the 1950s. Private sales represent 18% of the total. The city benefits from its reclaimed water treatment facility (funded and built in partnership with Shell Canada), which provides approximately 600 m^3/day to the city (of a total 4,000 m^3/day throughput from the facility). Shell Canada, because of their shift towards recycled flowback and produced water, sell part of their allotment to other industry operators. Any unused water is returned to Dawson Creek. As described in Section 4.2, the city carries out a monitoring program in the watershed. In addition to monitoring for water quality, they have installed two new climate stations and partnered with university researchers to improve knowledge of the watershed. There are few private domestic wells in the area, likely due to poor productivity of local aquifers, and many homeowners have to purchase bulk water.

The City of Fort St. John derives its municipal water supply from groundwater wells drilled in proximity to the Peace River (approximately 20 m away). There are five active wells, which each yield approximately 50-80 L/s. Wells are completed in a sand and gravel aquifer. The water is treated. The city has a combined permit; 50% from the Peace (main supply) and 50% from Charlie Lake (auxiliary supply). The city installed water meters in 2007/08, and water use declined despite an increase in population. In 2018, the city developed long-term water plans. Peak demands in summer in 2014/15 (due to the high level of industrial activity in the region and associated increase in population) were a concern because the wells needed maintenance, and so supply was limited. But industry has since slowed down and water use has been less. The city regularly inspects the water distribution line to look for evidence of landslides because of concern surrounding seismic hazards and potential rupture of the line. The city indicated that if something were to happen to its wells, they could get their treatment plant at Charlie Lake operational again (this was the city's first water supply way back). Similar to the City of Dawson Creek, Fort St. John is currently building a reclaimed water use facility, which should be operational by the end of 2018. It would have a capacity of 200,000 m^3/year. Any unused water would be returned to the river. There are a few private domestic wells within the city limits, but the wells are deep and the groundwater is hard, so most people haul water from the city system (approximately 6% of municipal water use). As well 6% of municipal water is used by industry.

Overall, neither the City of Dawson Creek nor the City of Fort St. John expressed concern about water quantity.

3.3.3. Other Evidence Considered

Surface Water - To aid in the management of the region's water resources, the BCOGC developed the Northeast Water Tool (NEWT). NEWT is a GIS-based hydrology decision support tool that combines hydrometric data (estimates of monthly and annual runoff volumes) with water licence and permitting records (Chapman et al. 2012, 2017) . A simple water balance model, driven by gridded climate data, vegetation, and watershed data, and adjusted for local variability, models mean annual runoff. The model is calibrated against gauged watersheds. Mean monthly runoff is modelled empirically, using multivariate regression. Figure 10 shows a screen capture of NEWT.

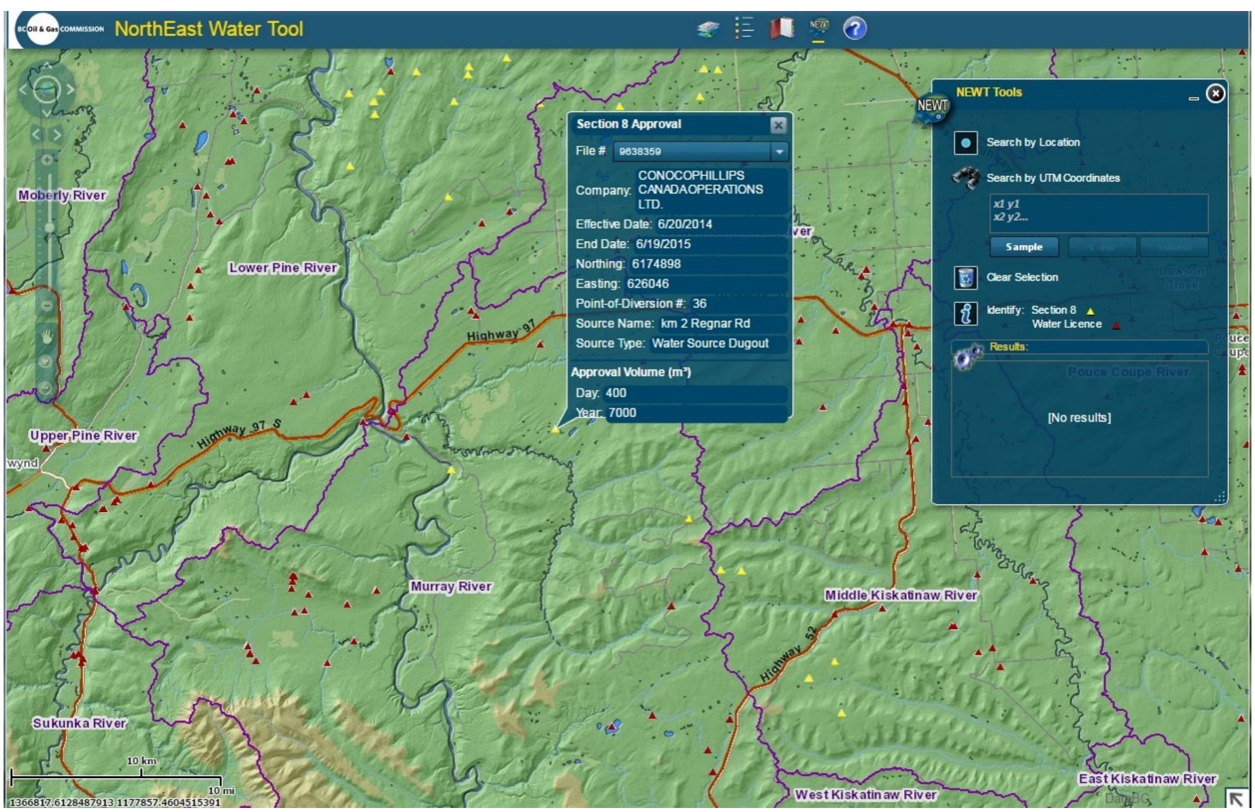

Figure 10. Screen capture of the North East Water Tool (NEWT).

NEWT represents an important step forward in water resource management for this data-scarce region and is used by the BCOGC to manage water allocations – with the goal of balancing EFNs with other industrial, municipal, and agricultural water demands. The EFNs of a stream are defined as the volume and timing of water flow required for proper functioning of the aquatic ecosystem. NEWT is used by decision-makers as a guidance on natural water supply and availability, and it is recognized to have several limitations and uncertainties. The primary limitation is that the estimated runoff volumes represent 30-year averages (Chapman et al. 2012). The hydrologic regime in NEBC is snowmelt-dominated, and streamflow is highly variable. Thus, in any one year, the observed conditions may differ significantly from the 30-year average runoff and from the annual and monthly runoff estimates in NEWT. NEWT also has a large amount of uncertainty associated with the underlying hydrologic modelling used to derive the monthly and annual runoff estimates. Mean error, median error, and mean absolute error for the annual runoff estimates were reported as 5.5%, 3.7%, and 16.1%, respectively, with 42 out of the 53 (77.8%) calibrated basins having annual runoff estimates within ±20% of the observed mean annual runoff values (BCOGC 2017)[26]. Additional uncertainty is present in the monthly runoff estimates from NEWT, which were calculated as a percentage of the estimated annual runoff using a multivariate regression model (Chapman et al. 2012). The BCOGC hydrology expert acknowledged several other limitations of NEWT, including the scale at which runoff is modelled. Specifically, NEWT is not representative of high elevations or small watersheds (18 out of 45 basins in NEBC are greater than 500 km^2). As well, NEWT does not account for groundwater. Chapman et al. (2017) state, "*since much of the study area is underlain by flat-bedded shales covered with thin glacial and postglacial deposits, infiltration to groundwater is believed to be a minor component of the water balance*." The authors cite Golder (2008) who conducted a water supply study in Alberta, and Abadzadesahraei et al. (2017) who studied the water balance of Coles Lake in NEBC. The Panel could not locate a copy of the Golder report. However, the Panel reviewed the findings of Abadzadesahraei (2018, PhD dissertation) and notes that the measured and modelled water balance for Coles Lake was highly uncertain, particularly in relation to groundwater. The observed groundwater levels were poorly reproduced, likely because the code used (MIKE SHE) does not simulate frozen ground processes. Moreover, the groundwater exchange with the lake could not be adequately quantified. Moreover, as described in Section 3.2.2, recharge in the Dawson Creek-Groundbirch area was estimated to range from 0.4 to 15% of precipitation (Baye et al. 2016). Holding and Allen (2015) simulated recharge for different ranges of precipitation across the Peace Region. For annual precipitation of 400 mm, recharge ranged from 28-128 mm with an average of 88 mm (22%). This range of recharge represents the majority of low relief areas of the Peace Region. Thus, recharge is not minimal as suggested by Chapman et al. (2017).

Dierauer (2018) simulated the hydrology of two small headwater catchments within the Montney Play: the 2.3 km^2 Graham River headwater catchment in the foothills and the 3.2 km^2

[26] BCOGC Northeast Water Tool, accessed December 14, 2017: https://water.bcogc.ca/newt

Blueberry River headwater catchment in the plains. Both catchments are located upstream of active gauging stations. The physically based Cold Regions Hydrological Model (CRHM) was chosen as the modelling code for that study because of its proven ability to simulate snow processes in diverse settings such as prairie and alpine basins. The CRHM models were structured as a set of four Hydrological Response Units (HRUs) corresponding to the major land cover features (water source dugout, developed oil and gas, clearcut/recent burn, forest and shrub). Within each HRU, physically based modules were sequentially linked to simulate the dominant hydrological processes (details on model parameterization are provided by Dierauer 2018). A detailed comparison of the modelling results with NEWT[27] estimates was carried out for the Blueberry catchment. Overall, the differences between NEWT-estimated runoff and the simulated Blueberry headwater catchment runoff suggest that the NEWT does not capture heterogeneity in the hydrological processes of smaller catchments (Dierauer 2018). In particular, differences between the NEWT-estimated monthly runoff and the actual monthly runoff, especially with regards to runoff timing and earlier than estimated freshet peaks, may result in an over-estimation of summer dugout water supplies for the region (Dierauer 2018). Dierauer (2018) also simulated climate change impacts on hydrology, and evaluated water management under different water use scenarios (not discussed further here).

Another comparative study of NEWT was completed in the Beatton River watershed, where NEWT hydrology was compared to the results of a physically based hydrologic model developed for the Beatton Watershed using the Raven Hydrologic Modelling Framework (MacDonald Hydrology Consultants Ltd. 2018). The framework used a modified version of the HBV-EC hydrologic model with some minor changes to the snow routine and soil infiltration algorithm. Baseflow in the deepest soil layer is simulated using the Variable Infiltration Capacity (VIC) routine. Thus, similar to the CHRM model used by Dierauer (2018), Raven does not explicitly simulate groundwater flow. Long-term average conditions are the only runoff values available from NEWT. Therefore, the comparison between Raven and NEWT relied on a visual assessment of average monthly runoff (mm) reproducibility at the five hydrometric stations. Comparisons of the 20% Mean Annual Discharge (MAD) were also made in order to evaluate potential differences in instream flow needs. Results of long-term average runoff conditions from Raven and NEWT were comparable across all sites, with NEWT performing modestly better than the Raven emulation of the HBV-EC model at Water Survey of Canada (WSC) sites. Results of long-term average runoff from both models are also similar across spatial scales. Importantly, the authors note "*comparison of NEWT outputs with runoff from WSC is not necessarily appropriate given that WSC data were used in the development of statistical relationships used in NEWT (Chapman et al. 2012). Therefore, NEWT outputs at WSC gauge stations are not independent of WSC hydrometric data*." "*The average runoff condition estimated by NEWT is not representative of the full range of potential runoff values. This is particularly important during the summer period, where low flows can be substantially less than*

[27] BCOGC Northeast Water Tool. Accessed December 14, 2017: https://water.bcogc.ca/newt

the long-term average. Being able to quantify the full range of potential flow conditions provides water resource managers with the ability to make more informed decisions." A climate impacts assessment was also carried out using the model. Similar to Dierauer (2018), the author stated that "*Water licensing decisions made using average conditions and short instrumental records are very likely to result in mis-guided recommendations which have the potential for over-allocation*." Finally, the pilot study highlighted some key limitations in using the HBV-EC modelling approach used within Raven, where late-season streamflow was generally over-simulated. This is a function of the inability of the HBV-EC model to represent storage-driven hydrologic processes properly. The Panel interprets this last statement as storage in wetlands and groundwater systems. Dandurand (2018) simulated groundwater flow in the Beatton watershed using the integrated land surface – subsurface modelling platform MIKE SHE and showed that variations in groundwater levels relate to climate variability. The analysis of these groundwater results highlighted implications of regional and local scale hydrogeological processes on pore water pressures in relation to slope stability along the Beatton River.

Source Wells - The Panel had access to 2014 data (provided previously by BCOGC) on water source wells, which it considers fairly representative of the current situation given that there have been few new licence applications for source wells [note: these data pre-date the WSA, and perhaps not all wells have been licensed under the WSA]. At the time, 122 wells were listed as water source wells, with measured depths ranging from 5.5 m to 2,800 m, presumably some of the deeper wells are horizontal wells. Over 100 of these were shallower than 600 m. However, only 46 of the 122 wells listed had reported water use over a three-year period since 2011 – thus only approximately one third of the wells were active. Regardless, the fact that over 80% of these source wells are relatively shallow, and would likely lie above the Base of Usable Groundwater, means that technically these wells primarily are extracting groundwater from the shallow (potable) groundwater zone. As such, the Panel expects that these wells are being captured under the WSA (as well as OGAA).

Deep source wells are being used by industry. Typically, such deep source wells lie below the Base of Usable Groundwater and can be expected to have a more saline groundwater chemistry. One major industry operator uses deep source wells for water supply at its water hub south of the Peace. North of the Peace, industry operators have suggested that groundwater is difficult to find (deep or shallow), which likely relates to the use of more surface dugouts in that area. This question was not fully explored by the Panel.

As mentioned in Section 3.3.2, groundwater use is regulated under OGAA (DPR) and/or WSA (Water Sustainability Regulation (WSR) and Groundwater Protection Regulation (GPR)) and EPMR. In addition, there are additional requirements through: 1) WSA water licence conditions; 2) the provincial drought response plan; 3) water source wells OGAA permit conditions; 4) BCOGC Oil and Gas Activity Manual; 5) Provincial Guidance WSS 2016-01 (Determining the Likelihood of Hydraulic Connection); and 6) Provincial Guidance WSS 2016-08 (Guidance for Technical Assessment Requirements in Support of an Application for Groundwater Use in BC).

The Panel reviewed these documents, and notes that several are updated on a regular basis. The BCOGC Water Licence Application Manual, for example, was last updated on January 8, 2018. It describes the overall process of applying for a water licence. Appendix C of the Water Licence Manual provides some information on hydrogeological assessment reporting required for water source wells. More detailed guidance for conducting a hydrogeological assessment, data submission, and monitoring in support of an application for a water licence under the WSA is provided in Supplementary Information for Water Source Wells[28]. If a company wishes to use an existing water supply well as a "water source well" a well permit application must be submitted, a licence must be granted, and the company must comply with all regulatory requirements under OGAA and WSA. Companies holding groundwater licences for water source wells are required to report monthly water use under regulatory requirements of Section 72 of the DPR.

Springs – Based on data provided by BCOGC, springs are not used by industry as a source of water. There are approximately 200 documented springs in NEBC, and it is assumed that these spring sources are used largely by private homeowners and for agriculture. A GIS based study on springs in NEBC was carried out by Bystron et al. (2017). This report could not be found on the BCOGC website, despite being funded by BC Oil and Gas Research and Innovation Society (BCOGRIS). The authors used a geostatistical analysis to map the likelihood of spring occurrence in Quaternary sediments and bedrock based on a range of spring related factors (e.g. topographic slope, slope curvature, surficial geology, etc.). The analysis focused on the Peace River Regional District. The study found that 8% and 5.2% of the area has a very high Likelihood of Occurrence for Quaternary and Bedrock springs, respectively. The subset of sampled springs verified the maps with a success rate of 76% (16/21) for Quaternary springs and 67% (10/15) for Bedrock sourced springs. Spring source areas (SSAs) were delineated; however, the authors conclude that uncertainties regarding each of the SSAs, due to assumptions in the methodology and poor resolution or quantity of hydrogeological data, result in a low degree of confidence in the SSAs. To the Panel's knowledge, these SSAs have not yet been included in BCOGCs Groundwater Review Assistant.

Dugouts – Mattison (2017) distinguishes three main types of dugouts used by industry: dugouts filled by surface water, dugouts filled by groundwater, and dugouts filled from indeterminate sources, but does not provide any geographic information on which types of dugouts may be more dominant in different landscapes in NEBC, or whether all types are found equally in different areas. By whatever means the dugouts are filled, they effectively store water for use in dry periods (late summer) when streamflow is insufficient to meet water demand. Unlike abstractions from streams and lakes, however, the use of oil and gas industry dugout water is not suspended during drought conditions. While the exact amount of water used by the oil and

[28] BCOGC Supplementary Information on Water Source Wells: https://www.bcogc.ca/supplementary-information-water-source-wells

gas industry from source water dugouts in NEBC is uncertain, it was roughly estimated at 2.2 million m^3 for 2015 (Mattison 2017). The BCOGC reported that 7.74 million m^3 of water was used for hydraulic fracturing in 2015 (BCOGC 2016)[29]; thus, approximately 28% of the water used in 2015 was sourced from dugouts.

Generally, the BCOGC is responsible for dugouts built on Crown land by oil and gas companies, while FLNRORD is responsible for dugouts constructed on Crown land by non-oil and gas companies and for dugouts constructed on private land. However, since the coming into force of the WSA, the BCOGC has been authorizing water storage and use by oil and gas companies on private land, both in cases where the oil and gas company owns the land and in cases where they do not. Any water withdrawals from dugouts constructed by oil and gas companies require permits and volume reporting; these volumes are reported quarterly by the BCOGC. The BCOGC Water Licence Application Manual states that if a borrow pit or other earthen excavation is used as a source of water that has naturally accumulated, it is referred to as a “water source dugout.” The water source type associated with a water source dugout is considered groundwater, and the Commission administers water source dugouts as diversions of water from “aquifers” under the WSA. An exception is where a stream is physically connected to the dugout, which may make the water in the dugout “surface water”. Approved stream diversions are common sources for large dugouts. When water is withdrawn from a water source dugout and used for an oil and gas activity, authorization is required either through a water use approval or through a water licence.

Generally, very little is understood about the effects of dugouts on the hydrology, particularly where the density of dugouts is high (e.g. Blueberry has many dugouts). First Nations have received numerous applications for dugouts, and they have observed applications for structures that hold as much as 150,000 m^3 of water. Sometimes the dugouts collect surface water and sometimes companies are asking to drill wells to pump groundwater to fill them. Overall, the representatives who spoke on behalf of Treaty 8 First Nations indicated that no concern is given to the aquifer, the taking of surface water, and the potential downstream impacts, but there should be.

Dugouts are not captured in NEWT. Dierauer (2018) simulated the hydrology of a small headwater catchment in the Blueberry watershed using the CRHM. The Wilcoxon signed-ranks test was used to determine if there is a significant difference in runoff between the CRHM model with the dugouts (dugout model) and the CRHM model without the dugouts (naturalized model). Water is only withdrawn from the simulated dugouts during the licensed withdrawal period (May 1st to August 31st). Correspondingly, runoff in the dugout model is significantly lower than runoff in the naturalized model in all months, except May. In May, the clay soils and no vegetation of the dugout hydrologic response unit result in lower infiltration and reduced

[29] British Columbia Oil and Gas Commission (BCOGC). (2016). Water Management for Oil and Gas Activity 2015 Annual Report: https://www.bcogc.ca/node/13261/download

early summer evapotranspiration (higher runoff) compared to the loam soils and shrub-land vegetation of the naturalized model. The median difference between annual runoff in the naturalized model and annual runoff in the dugout model is 8.75 mm/year, which is slightly higher than the total withdrawn/allocated runoff of 8.07 mm/year due to higher (relative to naturalized model) total annual actual evapotranspiration (AET) caused by the dugout water storage (Table 5.5 in Dierauer 2018).

In the small Blueberry headwater catchment simulated by Dierauer (2018), dugouts have the highest impact on runoff in summer (July-September) when water demand and ecosystem needs are high. While the combined impact of many dugouts (tens to hundreds) on runoff in larger watersheds in the Peace River region is not known, a recent study by McGee et al. (2012) showed that the cumulative effects of small water diversions on runoff in four larger (158-256 km^2) prairie watersheds in southern Alberta equal or exceed the reported effects of climate change. McGee et al. (2012) report a more than 5% decrease in annual runoff due to small diversions, suggesting that the widespread use of dugouts and stream diversions in the Peace River region of NEBC could have a significant impact on annual runoff in the region. Currently, no studies have been conducted in NEBC on the cumulative impacts of dugouts and small stream diversions on the hydrology of watersheds.

The future reliability of water source dugouts was analyzed by Dierauer (2018) by tabulating the CRHM-simulated monthly minimum dugout water levels. From model output for the 2020-2050 period, during the late summer (August) in drought years, the dugout water supplies were exhausted in the Blueberry catchment in both the historical and near future periods. Low dugout water levels (less than 20% volume) occur 24% more frequently in the near future period than they do in the historical period.

Similar to NEWT, the CRHM model does not simulate subsurface flow (i.e. groundwater). Thus, Dierauer (2018) did not simulate how much interaction there is between the dugout and the groundwater system. Moreover, no field based studies have been carried out to confirm the degree of connectivity.

3.3.4. Key Findings

The historical high volumes of water used in NEBC for hydraulic fracturing has raised concern about the sustainability of the resource, and the potential impact on the environment (e.g. ability to maintain EFNs). The Panel is encouraged to see that industry has begun to reduce its freshwater footprint, that there is new infrastructure to recycle and reuse water, and that a culture of water sharing is developing. However, development in NEBC has not been as frenzied as it was several years ago, and it is primarily the larger operators who are there for the long term that are making substantial investments in water recycling facilities.

There have been significant changes in how water is licensed in BC since the WSA came into force in 2016. Notably, groundwater use is now licensed. Moreover, the water source for dugouts is considered groundwater. While there is currently limited groundwater use through source wells by industry in NEBC, dugouts are a primary source of water in some areas. Whether private landowners are aware of the new regulatory requirements for groundwater (including dugouts) is unclear.

In 2014, BCOGC was designated under the *Water Act* to enable issuance of water licences for oil and gas purposes. Prior to this, the vast majority of oil and gas water use was authorized by the BCOGC through short term approvals. The intent with providing the BCOGC with water licensing authority was to have repeated water use from the same system or point of diversion under licence rather than short term approval and to encourage consolidation of water diversion into fewer diversion points from larger more resilient systems. This explains the applications for larger withdrawals and associated water transportation systems. These changes were intended to support better water conservation and compliance monitoring, and reduce trucking of water which has negative impacts on road users and residents. The BCOGC stated that, at present, companies are opting for longer term licences (rather than short term water use approvals) to avoid having to reapply. However, short term water use approvals have the advantage that they can be pulled in times of drought. BCOGC can place conditions on the licence or issue suspension orders. In regard to the licensing process, representatives who spoke on behalf of First Nations expressed the need for a better application process to give them more input in the pre-approval stage to set conditions. [As a side note, there was also an interest in First Nations stepping into a post-approval role for monitoring, etc.].

NEWT's limitations are partially overcome by the consideration of additional data and the issuance of directives to suspend water withdrawals from lakes, rivers, and streams in specified watersheds during drought conditions. Moreover, water allocations in watersheds in NEBC rarely approach the EFN thresholds. However, the combination of uncertain water quantity under a variable climate, combined with the highly variable hydrologic regime response, makes it difficult to identify reliable surface water sources for industrial use, especially during drought conditions when industrial water abstractions from rivers and lakes are often limited or suspended. The hydrology expert from BCOGC stated that statistics indicate that the past 10 years have been drier than "normal", which coincided with high water use by industry. One First Nation reported seeing water withdrawals at times when river flows were quite low, so they "*hear BCOGC saying one thing* [drought] *and yet continue to see withdrawals*." As discussed in Section 3.2 on climate change impacts, such dry years could be the new normal. Because NEWT uses historical averages for runoff, the estimates may not be sufficiently robust for water allocation during periods of drought. Therefore, NEWT should not be solely relied upon for water allocation decision making. Actual monitoring data should be required to support licence applications and short term use approvals.

Considering projected changes in climate, the expert from PCIC identified several key challenges that will impact how water is managed in NEBC into the future. Loss of snowpack and an earlier spring melt will result in an important shift in the hydrologic regime in NEBC.

Spring freshet will occur earlier in the spring, with a resulting earlier onset of streamflow recession and a longer and lower summer low flow season. Moreover, other changes in the cryosphere (e.g. a loss in lake ice extent and thickness, glacier loss and thinning, and disappearing permafrost) will affect the hydrology of the region. Groundwater recharge may also change due to the regime shift, although no studies have yet been carried out specifically in NEBC to project changes in recharge under a warming climate. Perhaps most significant is the loss of stationarity in the climate-hydrological system. Historically, in hydrology, the hydrologic system has been viewed as being stationary (i.e. a fixed envelope of variability). This paradigm is no longer statistically defensible; thus, how we manage water in the future will have to change. NEWT assumes stationarity, and so a shift in regime will not be captured by the model. NEWT may provide satisfactory estimates of annual streamflow if there is a shift in regime, but will perhaps not be appropriate for seasonal or monthly estimation of streamflow. Moreover, NEWT is subject to empiricism (e.g. how actual evapotranspiration is estimated, and how it will change in future). There is also irreducible uncertainty in the climate projections themselves, the large number of steps involved in making projections for water management, the assumptions we make in terms of emissions pathways, etc. This uncertainty needs to be considered in management decisions.

Overall, the requirements for hydrogeological assessment in support of an application for a licence for a water source well are reasonable and follow professional standards. However, the guidance documentation (BCOGC Water Licence Manual and Appendix C; and Supplementary Information for Water Source Wells) for applying for a licence for a water source well is unnecessarily complicated. There are simply too many documents, and the material presented is repetitive and hard to follow. The intent of the following statement in the Supplementary Information for Water Source Wells is not clear to the Panel: "*Note: The drilling of water supply wells to depths greater than 300 metres, where there is known potential for future application for an OGAA well permit for the well, is not consistent with the intent of the OGAA regulatory framework or the Commission's water source well permitting framework outlined in this document*" (p. 13).

In regard to the requirement for long-term monitoring for source wells, the guidance document Supplementary Information for Water Source Wells indicates that if a potential for hydraulic connectivity with surface water bodies or other water wells is determined during the hydrogeological assessment, then long-term monitoring should be undertaken. It is the understanding of the Panel that hydrogeological consultants in the province have been having difficulty carrying out such assessments, particularly in relation to assessing EFNs as described in Provincial Guidance WSS 2016-01 and Provincial Guidance WSS 2016-01.

In Section 2.1 of Supplementary Information for Water Source Wells there is a statement, "*The Commission recommends for all water supply well drilling in Northeast B.C. consultation with a qualified professional (i.e. the Association of Professional Engineers and Geoscientists of BC –* now Engineers and Geoscientists BC*) occurs to ensure due diligence in relation to safety and the* *potential for shallow gas, and environmental protection*." The guideline states that various activities (designing the assessment program, determining the duration of the pumping test, determining the locations and depths for monitoring wells for the pumping test, determining an appropriate distance for notifying well owners about the pumping test, identifying surface water bodies that should be monitored) should be carried out by a qualified professional. At the same time, Provincial Guidance WSS 2016-01 indicates that a person wishing to establish a new non-domestic groundwater supply may be required by the statutory decision maker to have a technical assessment completed by a professional with competency in hydrogeology. Provincial Guidance WSS 2016-01 indicates that the document provides technical guidance to decision makers, water allocation staff, and professional hydrogeologists. Thus, it is the view of the Panel that the various activities described above as falling under a hydrogeological assessment must be overseen by a qualified professional.

The oil and gas industry relies on water stored in dugouts for water supply when streamflow is insufficient to meet water needs. Mattison (2017) carried out a comprehensive review of current policy and legislation pertaining to water use from dugouts in BC, as well as provided thoughts on approaches for compliance and enforcement. The Panel considers this review to be comprehensive and has nothing further to add. However, understanding of the influence of dugouts on the hydrology, as well as the potential interaction between dugouts and groundwater is limited. Dieraurer (2018) concluded by stating additional research is needed to quantify the relationship between dugout volume, water-source reliability, and runoff impacts.

3.3.5. Recommendations

Water management in NEBC is complicated because both FLNRORD and BCOGC can issue licences. Most importantly, the estimate of annual water use by BCOGC excludes water use by industry through sales from private landowners. Right now, no one really knows how much water private landowners are selling to industry. Communication between BCOGC and FLNRORD has deepened with the joint work done on assessing dams and dugouts in 2017 and is supported by an MOU addressing WSA Administration. The MOU enables further licensing of third parties (usually private landowners) providing water for oil and gas purposes. Requiring operators to report the use of water obtained from sources on private land will allow the BCOGC to more accurately report on water use related to hydraulic fracturing, thereby improving transparency. Moreover, increased regulatory authority by BCOGC over the use of water obtained on private land (i.e. through sales) could allow the BCOGC to better manage water use, particularly in periods of drought (Ernst and Young 2016).

Licensing of groundwater under the WSA is in a period of transition. Current non-domestic users of groundwater from an aquifer, including storing the water in a dugout, can continue to use and store that groundwater but must apply for a licence before March 1, 2019 and may continue to use and store the water until a decision is made on the application. Given this looming deadline, the Panel questions how many existing users of groundwater, including use for dugouts, are aware of this deadline. FLNRORD's position is one of education for private landowners, but whether the message of licensing requirements is being delivered to, and being acted upon by, private landowners is uncertain. Government should immediately take action to inform private landowners of their obligations to obtain a water licence under the WSA.

There remains considerable uncertainty on the part of environmental consultants (working in NEBC and elsewhere) about assessing the potential impact of a proposed water supply on EFNs. Government provides technical guidance to decision makers, water allocation staff, and professional hydrogeologists. Thus, it is the view of the Panel that the various activities described as falling under a hydrogeological assessment <u>must</u> be overseen by a qualified professional.

Total authorized water use by the oil and gas industry in NEBC is estimated by the BCOGC to be a very small fraction of total runoff (approximately 0.1% of total annual water volume available), and reported water use is even less (approximately 0.01% of total annual runoff). The Panel considers that while the estimate accurately reflects authorized water use by industry, the estimate is misleading for two reasons. First, the majority of runoff in the Peace Region occurs during spring freshet, and seasonal water use as a percentage of seasonal runoff is different. BCOGC should cease making reference to average annual water use in public documents and report seasonal (or monthly) water use for better transparency. Second, the estimated water use does not consider use by industry through sales from private landowners as discussed above.

In an effort to reduce their water footprint, operators have been proactive in recycling and reusing produced water. Over the past few years, major water hubs have been developed. Industry operators are sharing water, and reclaimed water facilities have been constructed and are operational. Industry is proud to show its reduced water footprint. The Panel recommends that this information be shown publicly because, currently, alternative water use is not considered. Moreover, requiring operators to report the use of water obtained from alternative sources, such as municipal grey water or water purchased from municipal water supplies would allow the BCOGC to more accurately report on water use related to hydraulic fracturing, thereby improving transparency (Ernst and Young 2016). There should be incentives for industry to recycle and reuse water, with a long-term goal of making recycling and reuse of water mandatory for all operations (i.e. including smaller operators who have not yet moved in this direction).

Limited climate, hydrometric and groundwater data in NEBC make it difficult to assess the potential impacts of water use (surface water, groundwater, dugouts) on the environment. A complicating factor is that while information on water use is available, it is often outdated. Currently, three tools are used to access and view information: the Water Portal, the Groundwater Review Assistant, and NEWT. Ideally, a single platform would integrate all data and display it in real time. This may not be achievable in the short term, but it should be a long-term goal.

Additional comparison studies of NEWT against other hydrological models (calibration exercises) should be undertaken to answer a range of questions such as: How well does NEWT handle drought conditions? How well are flows in small headwater catchments estimated? A post analysis should also be carried out in sensitive watersheds to compare what NEWT predicts according to average climate, what is measured at the gauge, and what the discrepancies are.

An audit of water use in randomly selected watersheds should be undertaken. Such an exercise should include a review of all water licences (under WSA and OGAA), the conditions attached to the permits and whether they have been met, analysis of data provided by industry (pre- and post-development), etc.

The cumulative effects of hydraulic fracturing on water resources should be evaluated to determine if there are cumulative effects, trends, or problems, and to identify the cause(s). Watersheds with different sensitivities should be compared, and traditional knowledge alongside historical climate and hydrological data should be used in the assessment.

Climate extremes need to be examined, especially drought, to answer questions related to historic drought frequency and duration and how these compare to current observations and future projections. There is strong evidence that summers will become drier under a warming climate, and there is not a lot of natural storage (lakes) in NEBC to buffer changes in hydrology. Thus, drought impacts could intensify in future. Perhaps limited term licences should be considered for some watersheds that have less stable streamflow conditions (i.e. that are sensitive to year to year climate variability). Do we even know which watersheds these might be?

Mattison (2017) lists twenty-seven recommendations in relation to dugouts. FLNRORD's Fact Sheet indicates how government is using these recommendations. As the document was prepared in December 2017, and it is now one year later, government should report on progress made on the issue of dugouts. Note: some of these recommendations pertain to dams as discussed in Section 3.4.

Given the recent introduction of the WSA, the Panel considers it premature to comment on how well this new regulatory framework is working out. The Panel heard some evidence by government staff and industry that the transition has not been smooth. Thus, it is critical that government and the Regulator do not become complacent. "Glitches" in the licensing system should be addressed quickly to avoid problems (such as the dam issue discussed in the following section). Careful consideration of the effectiveness of new regulations and policy should be carefully examined. The Panel recommends that a thorough review of the water use approval process be undertaken in 2-3 years.

3.4. Large Water Storage Structures (Dams)

3.4.1. Concerns Raised

During the Panel's site visit to NEBC the week of May 14, 2018, the Panel was taken to a large water storage structure, clearly identifiable as a dam. It was explained by the BCOGC expert guiding the site visit that following the introduction of the WSA in 2016, the BCOGC was made aware that a number of water storage structures it had approved (to support hydraulic fracturing operations) met the definition of a dam. As such, these should have triggered additional authorizations. The operator who constructed these dams did not do so at the time of their construction, and therefore the structures were not in compliance with the WSA.

Concerns were expressed to the Panel regarding these dams by representatives who spoke on behalf of Treaty 8 First Nations and ENGOs. Representatives who spoke on behalf of Treaty 8 First Nations raised two key concerns. The first was a safety concern whereby any breach of these dams could result in the sudden release of the stored water, causing a flood wave with the potential for triggering debris flows, significant damage, and loss of life. A second concern, which also applies to the even larger number of dugouts constructed (dugouts were discussed in Section 3.3), is the question of where the water is being diverted from to fill these structures and what the implications/impacts might be on local stream flows and aquifers.

Concerns were also expressed by ENGOs, who considered this occurrence of large dams being built without proper oversight as a failing of the application and licensing process. Given the absence of regulator oversight in reviewing these structures during their construction, the Panel also questioned whether the proper level of engineering and quality control/assurance had gone into their construction. For example, it was observed at the large dam visited by the Panel that there did not appear to be any spillway or outlet facility built with the dam to protect against over filling and overtopping of the dam in the event of a period of heavy, sustained precipitation. This is discussed in more detail in the following subsections.

3.4.2. Summary of Expert Evidence Presented

The high demand for water for hydraulic fracturing activities in the Montney region has resulted in a large number of fresh water storage structures being constructed, both on Crown and private land. In a presentation to the Panel, it was explained by a BCOGC expert that the diversion and storage of freshwater in BC is regulated under the WSA (and previous to its introduction in 2016, by its predecessor the *Water Act*). This requires a water licence issued under the Act.

It was next explained by the BCOGC expert that following the introduction of the WSA, BCOGC became aware that a number of fresh water storage structures it had approved and issued short-term water permits for met the definition of a dam. This deviated from the more common practice of constructing dugouts to store fresh water. A dugout is generally defined as a structure that is constructed below the ground level such that the water it contains is stored below the surrounding ground surface (Figure 11a). This contrasts with a dam, which is defined as a structure built in part above the ground level such that the water it contains is stored above the surrounding ground surface (Figure 11c and d). This is referred to as live storage.

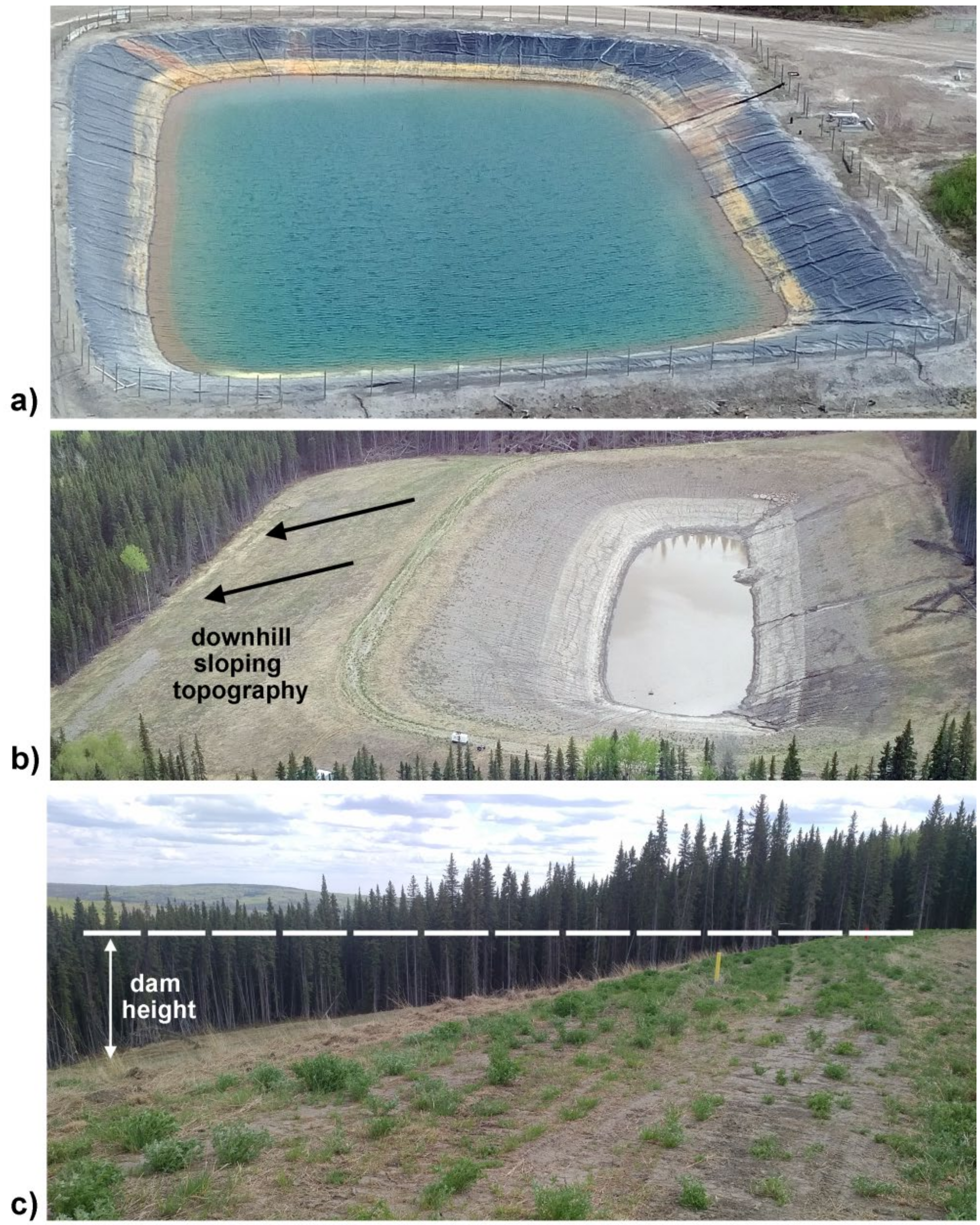

Figure 11. Photos taken during the Panel's site visit to NEBC the week of May 14, 2018, showing: a) an example of a dugout, in this case for waste water storage, where storage is below ground level; and b,c) one of the large unauthorized dams, where fresh water storage is above the downhill sloping ground.

In describing how these fresh water storage dams were constructed without notice of the Regulator (BCOGC), it was explained by the BCOGC expert that this was due to changes in regulatory responsibilities, coupled with a reliance on previous experiences. Responsibility for these authorizations was initially that of FLNRORD, which has a Dam Safety Group and Dam Safety Officers. However, in 2013, responsibilities for issuing water licences specific to oil and gas operators were passed to the BCOGC. According the BCOGC expert, in this transfer of responsibilities it was apparently missed that the licence applications to the BCOGC by operators should include detailed specifications as to how fresh water was going to be stored (e.g. dugout or dam). It was explained that BCOGC's early experience with large water storage structures was drawn primarily from the Horn River Basin where the ground surface is relatively level and the structures built involved dugouts. When hydraulic fracturing activities shifted more to the Montney and the undulating terrain of the foothills, the resulting fresh water storage structures were required to be constructed on sloping ground, thus resulting in dams. This apparently went unnoticed until 2016, when BCOGC was given the authority to inspect dams under changes to the Dam Safety Regulation (DSR) of the WSA.

In a presentation to the Panel by an ENGO on this topic, their estimate was that 51 earth dams were built during this period, and that this number might be as high as 92. These numbers were derived from a report by Mattison (2017) prepared for FLNRORD on *Managing Dugouts in Northeastern British Columbia*. The presenter stated that, "*Roughly half of the 51 structures that the BCOGC allowed to be built on its watch fully qualified as dams under the old Water Act and were required to conform to the rules and regulations then in place. The most important of those regulations was that companies could not build dams without first having applied for and obtained water licences.*" The presenter noted that this is important because, *"the company responsible for the majority of the dams has suggested that it was only as a result of passage of the new Water Sustainability Act that the company had been forced, retroactively, to apply for water licences. However, many of their dams were purposely built to trap water from surface water sources such as streams. The older Water Act clearly required anyone seeking to divert water from such sources to first apply for and be granted water licences. There was also a clear requirement, given the size of the dams, to submit any plans to build such structures to the relevant provincial agency. That did not happen either.*"

In August 2016, the BCOGC issued a bulletin[30] to industry operators specifying new application requirements for freshwater storage sites. This included information describing the type of water storage infrastructure planned, and that, in the case of a dam (live storage), the structure must comply with the DSR and construction and operational standards specified by FLNRO (now FLNRORD). In the presentation by the expert from BCOGC, it was stated that by 2017 all dams constructed were inspected and details from the builders were provided and orders written. Of the approximately 50 earth dams built, operators indicated they wished to maintain 30 of these, for which they were placed under review to ensure that they conform to dam

[30] Industry Bulletin 2016-26: https://www.bcogc.ca/node/13389/download

safety guidelines. Several others have since been decommissioned. It was noted that dams on private land fall under FLNRORD's responsibility, and that although some of these have been properly authorized, some were not. These are currently being dealt with by FLNRORD in collaboration with BCOGC.

With regards to the impacts of these unauthorized dams, representatives who spoke on behalf of Treaty 8 First Nations stated, "*Fresh water used to be more accessible and the ground surface more marshy (more wetland). This has changed. The diversion of fresh water to large water storage structures have altered these wetlands such that the plants that had medicinal value no longer grow, and the spiritual meaning of the places where they grew is lost.*" It was also felt by the representatives that safety concerns prevented the full utilization of traditional Treaty Rights below these dams; for example, camping below these unauthorized dams was considered to be unsafe. In both cases, the representatives did not give their free and informed consent on these dams as they were incorrectly described as "pits" in their licence applications when sent to First Nations for review.

3.4.3. Other Evidence Considered

The Panel reviewed data provided by BCOGC on their "Regulated Dams" website[31] regarding the year these dams were constructed and their size. The data provided show approximately 30 dams that were constructed over a 5-year period between 2011 and 2015, prior to the WSA and new DSR being introduced in 2016. These range in size with respect to storage volume from 17,000 m^3 up to 183,000 m^3. Four of these are over 100,000 m^3.

The Panel also reviewed the older *Water Act* and DSR that was in place prior to 2016. It is noted in the BCOGC Water Use for Oil and Gas Activity 2013 Annual Report[32] (the last report before the WSA was introduced), that under OGAA, BCOGC has the authority to issue water use permits under Section 8 of the *Water Act* to manage short-term water use by the oil and gas industry. These approvals are stated as including allowances to divert water for a term not exceeding two years, but that through Directive 2011-02, companies holding short-term water use approvals must submit monthly water withdrawal data to the BCOGC for each approved withdrawal location, commonly known as a point-of-diversion. The examples provided are, "lake, stream, water source dugout, etc." It is noted by the Panel that there is no mention of dams.

In a review of the previous DSR[33] that was in place under the older *Water Act*, the Panel notes that similar requirements were in place for dams with heights of 7.5 m or more. Similarly, requirements under the Reviewable Projects Regulation under the *Environmental Assessment*

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[31] BCOGC Regulated Dams Website: https://www.bcogc.ca/public-zone/Regulated-Dams

[32] BCOGC Water Use for Oil and Gas Activity, 2013 Annual Report: https://www.bcogc.ca/node/11263/download

[33] Dam Safety Regulation in place under the *Water Act* prior to the 2016 update: http://www.bclaws.ca/civix/document/id/complete/statreg/44_2000_pit

*Act (*EAA*)*, both before and after 2016, both indicate that a “new dam” with height equal to or greater than 15 m would be a reviewable project. During the Panel’s site visit to NEBC the week of May 14, 2018, it was observed at the dam visited by the Panel that the height of the dam was clearly greater than 15 m. It is not clear to the Panel whether an EAA review was conducted of this or any of the other dams constructed by oil and gas companies during the 2011 to 2016 period, but BCOGC’s indication that it was unaware that short-term water permits were granted to water storage structures that were in fact dams, suggests that no proper regulatory reviews were carried out for these dams before or during their construction.

In terms of dam safety, it was noted during the Panel site visit that there were signs of performance monitoring in place (an inclinometer and two piezometers), but it was also observed that there was no spillway or outlet facility built with the structure (Figure 11b). Spillways/outlets are a critical component of a large earth dam to protect against over filling and overtopping of the dam due to heavy precipitation, which can subsequently lead to a runaway process of erosion of the dam material, breach, and catastrophic failure. It is recalled that in 2010, a small privately-owned earth dam in the Okanagan (Testalinden Dam[34]) failed in part due to an insufficient or blocked spillway that led to overtopping of the dam. This resulted in $9 million in damages and luckily avoided injuries or fatalities given that the resulting flood and debris flow impacted a populated area. According to the DSR (Section 18b), dam owners are required to test the operation of their outlet and spillway facilities on a set schedule; thus the earth dam visited by the Panel appears to be in violation as such a facility was not even constructed.

3.4.4. Key Findings

The Panel found that the construction of a series of large earth dams between 2011 and 2016 for the purpose of storing fresh water to support hydraulic fracturing activities, appears to have escaped the proper regulatory oversight. In several cases the dams were large enough that they should have required additional reviews and authorizations under the Dam Safety Regulation, the *Water Act*, and the *Environmental Assessment Act* (as these were in place at the time of their construction). In effect, the companies responsible appear not to have submitted all necessary applications, and treated the structures as dugouts instead of dams. However, it was noted that at the time these dams were being constructed, the *Water Act* was in the process of being replaced by the WSA (Feb. 29, 2016) and responsibilities for fresh water storage specific to oil and gas activities were being transferred from FLNRORD to the BCOGC, and that exceptions and complexities to this transfer prevented a straightforward determination of which authorities would be responsible (e.g. leasing arrangements between oil and gas operators with private land owners). This has since been corrected and the requirements for

[34] Testalinden Dam report: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-resource-use/land-water-use/water-use/dam-safety/testalinden_slide_failure_review.pdf

constructing a dam for fresh water storage for oil and gas activities are clearly described in the BCOGC's *Oil and Gas Activity Application Manual* [35] (Ch. 4.7).

The Panel visited one of these earth dams, observing that it had a built height of approximately 20 m. This should have triggered requirements falling under the *Water Act* and DSR, as well as EAA as it exceeded the 15 m height requirement for reviewable projects under the EAA. The source of the water filling this dam was not clear (surface runoff, stream diversion, groundwater), but inspection of the site suggested surface runoff (snow melt and precipitation); unless the dam was constructed to intercept a stream that was not flowing at the time of the Panel visit. It is noted by the Panel that prior to the implementation of the WSA in 2016, water users did not require an authorization to divert, use, or store water from an aquifer by means of a dugout. However, Section 6 of the WSA now establishes a general requirement that users obtain an authorization to divert and use fresh water from a stream or an aquifer.

The operator of the dam visited by the Panel did not seek the required reviews. Opinions were expressed to the Panel that this and other similar examples point to a failure of the regulatory process. The Panel found it disconcerting that an operator would proceed with building a large dam without questioning whether some level of disclosure to the regulator should be made or being ignorant of requirements under other BC regulations and acts.

Safety concerns follow as the absence of proper regulatory oversight during the construction of these dams creates uncertainty as to the level of engineering design and quality control in place during their construction. Under the DSR, the owner of a dam greater than 7.5 m in height must prepare a manual that describes the operation, maintenance, and surveillance procedures for the dam, and submit the manual to a Dam Safety Officer for acceptance. With the introduction of the WSA in 2016, the DSR requires existing dams that have not submitted an operation, maintenance, and surveillance manual, to do so. In addition, if the consequences of a dam failure are classified as significant or higher, the owner must prepare a dam emergency plan describing the actions to be taken in the event of an emergency. This latter requirement is stricter than the previous requirement under the DSR in place during the older *Water Act*, which required a dam emergency preparedness plan for dams classified with a failure consequence of high or very high. For comparison, a dam is classified as having a significant consequence when the population at risk is only temporary and there is a low potential for multiple loss of life, or where no significant environmental, cultural, infrastructure, or economic losses would be incurred. Alternatively, a dam would be classified as having a high consequence when the population at risk is permanent and there is a potential for up to 10 fatalities; where there is significant loss or deterioration of fisheries or wildlife habitat, rare or endangered species, unique landscapes, or sites having significant cultural value; or where there is high economic losses affecting infrastructure, public transportation, services, or commercial

[35] BCOGC's Oil and Gas Activity Application Manual: https://www.bcogc.ca/node/13281/download

facilities, or severe damage to residential buildings. Given the low population density in NEBC, the stricter requirements under the updated DSR would certainly apply to the water storage dams constructed if they hadn't before. It was noted by the BCOGC that the requirements of the DSR are being applied to all remaining dams under BCOGC authority. Until the dams fully meet those requirements, dam owners are not permitted to operate the dams.

It is also recognized that the impacts of these dams on the surrounding environment were likely not investigated since they did not go through the proper vetting required by the *Water Act*, and in the case of the larger dams, the EAA. If this was in violation of the regulations that existed at the time of their construction, it would be expected that they should still be subject to any required assessments. Requirements outlined in the BCOGC's *Oil and Gas Activity Application Manual* for short-term water use (Ch. 4.7) suggest that today, water withdrawals from these dams should be subject to an environmental flow assessment if there is a potential hydraulic connection to a stream or wetland within 50-100 m, and if more than the equivalent of the storage volume of the dam is being withdrawn in a year.

Moving forward, it is recognized that the regulatory failures that initially allowed dams to be constructed without the proper oversight have since been corrected and the requirements for constructing a dam for fresh water storage for oil and gas activities are clearly described in the BCOGC's *Oil and Gas Activity Application Manual*. It is also recognized that the need for fresh water storage appears to be on the decline as operators have begun to reuse produced and flowback water. If so, it is important that these dams are not forgotten or fall into a state of neglect from non-use, and that they are properly decommissioned before they become a liability for the Province. Given current issues with orphan wells, it is important to avoid a future problem of orphan dams.

3.4.5. Recommendations

Responsibilities for regulating fresh water storage should be clear and straightforward. Any gaps in responsibilities that arise should be quickly resolved, and regulatory requirements retroactively enforced. Enforcement should be transparent, consistent, reliable, and effective to re-establish public trust. In his report on dugouts for FLNRORD, Mattison (2017) provides a number of recommendations regarding data gathering, awareness, compliance, enforcement, and monitoring. FLNRORD have responded with a fact sheet[36] on how they are responding to these recommendations. This includes the creation of a 'Dugout Database' (which the Panel suggests be named to acknowledge the inclusion of dams), and determination of land ownership and responsibilities for each dugout/dam, presumably clarifying oversight issues around water storage structures built on Crown versus private land. Mattison recommends

[36] FLNRORD Fact Sheet on Managing Dugouts in NEBC: https://www2.gov.bc.ca/assets/gov/environment/air-land-water/water/dam-safety/fs_dugouts_mattison_dec_2017.pdf

sharing this database with the BCOGC, but it is recommended by the Panel that this database be made publicly available to improve transparency and public confidence.

It is understood by the Panel that operators who dams built in excess of 15 m height have retroactively submitted applications to the Environmental Assessment Office (EAO), and these were reviewed and exempted (on July 16, 2018). Still, these dams should be required to submit their operation, maintenance, and surveillance manuals, and dam emergency plans, as stipulated under the DSR and otherwise required for any other large dam constructed in the Province. If deficiencies in design or construction are identified that result in safety concerns (e.g. absence of overflow controls), or the dam is assessed as having a significant impact on the environment or Treaty Rights, corrective measures should be enforced to bring the dam into compliance. It is important for public confidence that operators are not seen as being rewarded or able to skip important regulatory requirements that are in place to ensure safety and avoid significant impacts to the environment, by being ignorant of or willfully disregarding regulatory requirements and statutes.

Major water storage structures should be visited and inspected by BCOGC staff with the proper expertise to ensure proper design, construction, and compliance with regulations. In his report, Mattison (2017) recommends that two new Dam Safety Officers be recruited and trained for the Fort St. John FLNRORD office, and FLNRORD has responded that one of these new officers have been hired. It is important that this new officer and other FLNRORD Dam Safety Officers work together with BCOGC and their Dam Safety Officer and Dam Integrity Engineer. It is noted by the Panel that data on the BCOGC Regulated Dams website show that there have been at least six new dams constructed in 2017 and 2018; i.e. after the detection of the unauthorized dam issue with the introduction of the WSA in 2016. Three of these are over 100,000 m^3 in storage capacity, and one is listed as having a storage capacity of 200,000 m^3. The seeming fact that two or more large dams were constructed without notice of the different Regulators responsible for a considerable amount of time raises questions regarding the level of oversight at the time, and offers a lesson learned to improve this.

For dams classified as "large dams", plans for decommissioning and reclamation should be required. The liability these dams represent should also be evaluated to determine whether bonds should be imposed to ensure decommissioning and reclamation costs are fully covered.

3.5. Wastewater Disposal

3.5.1. Concerns Raised

The activity level of horizontal drilling and hydraulic fracturing in the Montney Unconventional Play in NEBC has steadily increased over the last decade. "*This increased activity has caused a significant increase of the volume of water required for the makeup of frac fluid, and, concomitantly, the disposal of the recovered frac fluid*" (Petrel Robertson Consulting Ltd. 2015).

Significant concern was expressed by government staff, the regulator and industry about insufficient capacity for wastewater disposal in NEBC. This concern will become critical if shale gas production continues to grow, and towards the end of development in NEBC when ultimately all wastewater will need to be disposed of.

For the purposes of this section and Section 4.5, the term wastewater is used to describe fluids recovered from well completion or workover operations (including flowback fluids from fracture stimulations) as well as subsequent produced water recovered during operations. This definition is consistent with that used elsewhere (e.g. U.S. EPA 2016). Details concerning regulation and permitting are discussed in Section 4.5 as these relate more broadly to issues of contamination. In this section, wastewater disposal is discussed from a water quantity perspective. Induced seismicity in relation to wastewater disposal is discussed in Section 5 of this report.

3.5.2. Summary of Expert Evidence Presented

In BC, all wastewater is disposed of by injection into deep geological formations. The BCOGC guidance document on Water Service Wells (which includes disposal wells) states, "*Water produced in association with oil and gas must be disposed into a subsurface formation via an approved disposal service well. Disposal is not permitted into an aquifer containing water usable for domestic or agricultural purposes, or a zone that may pose risk of contamination of such a water aquifer. The protection of water resources is of primary importance to the Commission*." There are two options for disposal: depleted hydrocarbon pools and deep aquifers. Disposal formations must be shown to be contained by impermeable cap and base formations, competent to contain fluid within the area of influence. There are special permit conditions for disposal wells, including that the integrity of wells within a 3 km radius of the disposal well be taken into consideration. Maps showing known faults within 20 km of the proposed disposal location must be submitted, including 2-D or 3-D seismic mapping showing structures and faulting for the area. A geological cross section with information on the disposal reservoir/aquifer, injectivity testing results, identification of the Base of Usable Groundwater, discussion of fresh groundwater wells within a 3 km radius, among many other requirements, are part of the permit application. Disposal wells are further subject to operating, monitoring, testing, and reporting requirements as conditions of individual approvals, appropriate to specific circumstances.

There is strong evidence that wastewater disposal capacity in NEBC is limited. Industry strongly expressed this concern, and it was echoed by government and the regulator. The ENV expert on wastewater management for the Province stated, "*In the peak of boom (6-7 years ago) there were cases of trucks lining up to wait at disposal facilities (2-4 hour lineups). If LNG ramps up again, [there would be] more pressure on these disposal wells. From a technical perspective, there are limits on pressure and flow due to potential seismic influences, and there are also potential impacts to neighbouring oil and gas wells and other disposal wells*."

Industry recognizes the limited capacity of disposal formations and is trying to limit its need for disposal through recycling and reuse of water used for hydraulic fracturing. While some disposal reservoirs appear to have good capacity (e.g. Cadomin Fm.), many others do not. Various operators expressed knowledge gaps including: 1) "*We need to understand reservoirs where injection is taking place*"; 2) "*We need to understand what else they can do with the water to reduce the amount that needs to be injected*"; 3) "*If activity levels drop off again, what do we do with this water?*" As an example, one operator currently stores 630,000 m^3 of wastewater for potential future use for hydraulic fracturing.

Industry has taken a lead role in innovation related to recycling and reuse of water, not only in an effort to reduce water use, but also to reduce the volume of wastewater being produced. Recycling and reuse were discussed previously in Section 3.3. Several industry operators spoke about the need to explore new technologies for wastewater filtration and treatment.

One major operator has submitted a preliminary application to BCOGC to distill wastewater and return the distillate (discharge it) to surface water. The proposed design would be to treat 300 m^3/day and release 100 m^3 /day to the Kiskatinaw River leaving 100 m^3/day of waste (60 m3/day liquid and 40 m^3/day solid). According to the operator, First Nations received the concept positively as did local communities. ENV reviewed the proposal and indicated that the returned water would have to meet BC surface water quality objectives (see Section 7.2). BCOGC did not provide information on this application.

While on a tour of a third party wastewater disposal facility, the Panel heard from the facility's staff who mentioned that they are interested in expanding operations to include reuse, rather than only disposal. The ENV expert on waste management indicated several key challenges including lack of policy and process for non-producer re-use facilities, and that there is no policy in place for third party service providers to reuse. The same concern was raised by a third party service provider during the Panel site visit.

3.5.3. Other Evidence Considered

Some research has been done in BC surrounding wastewater disposal. Geoscience BC commissioned several studies on subsurface aquifers to support unconventional oil and gas development (e.g. the Horn River Basin - Petrel Robertson 2010, 2012; the Montney – Petrel Robertson 2011; the Liard Basin - Petrel Robertson 2014). A focused study on deep aquifer fluid disposal was also carried out for the Montney region (Petrel Robertson 2015; Canadian Discovery Ltd. 2015), the latter including a hydrogeological analysis and a geomechanical analysis. It was beyond the scope of this review to explore these reports in detail. However, it is apparent that while there is some capacity for disposal in certain geological formations, limited permeability, compartmentalization, and geomechanical risks limit disposal capacity in many areas of NEBC.

Simons (2018) simulated a relatively short wastewater disposal history for several wells in the Paddy-Cadotte. Source wells are also completed in this disposal unit. The modelling results showed that wastewater disposal plumes are influenced by nearby disposal wells and source wells; the plumes are drawn slightly toward source wells, and are pushed away slightly from the other nearby disposal well. The simulations better represent the migration of plumes in disposal formations compared to simple volumetric estimates because the physical process of dispersion and density effects are explicitly modelled. While the deviation of the migration pathways was not large, the results suggest that the potential for interference between wells (both disposal and source wells) should be considered in permit applications.

3.5.4. Key Findings

The resounding concern about disposal capacity in NEBC was not anticipated by the Panel, and points to a critical need to begin planning for the short and long-term future of natural gas development in NEBC. There was a clear message that the capacity for wastewater storage is inadequate to meet the anticipated increase in production over the coming years. Thus, it is paramount to either reduce the amount of wastewater being generated or find alternative options for disposing of this waste. The wastewater facility proposed by one operator is one potential avenue; however, the Panel cannot emphasize enough how critical it is to exercise caution. Although the ENV expert on waste management did not elaborate on which water objectives would need to be met if the facility is approved, the Panel assumed this meant surface water quality objectives as it is not aware of any surface water quantity objectives. While surface water quality objectives would capture various chemical and physicochemical (i.e. dissolved oxygen) parameters, there are currently no water objectives related to Naturally Occurring Radioactive Materials (NORM), as discussed in Section 4.6; although any discharge of potentially harmful water would require regulation through EMA before it could be legally discharged. Moreover, water quantity objectives would need to be met to assure that volumes of discharge would not compromise aquatic habitat. Just as there are minimum flow requirements to meet EFNs, different species may be equally sensitive to high flows.

3.5.5. Recommendations

Short and long-term planning for disposal of wastewater should be initiated. As stated by one operator, there is no solid understanding of the volume needed and disposal requirements in the Montney for growth scenarios. An inventory should be carried out on how much wastewater is currently being stored by various operators, how much is being produced yearly, what the actual disposal capacity of the various identified disposal formations are, and how long it might take (in years) to reach capacity given well injection limitations. This problem is not going to go away and it may take years to introduce regulation or policy related to new initiatives, such as that proposed by one major operator. During this process, careful consideration should be given to induced seismicity (as discussed in Section 5), as well as the potential for disposal wells to impact neighbouring oil and gas wells, or other disposal or source wells.

The Panel recommends that government act now to address the lack of policy and process for: 1) non-producer re-use facilities, and 2) emerging technologies for treated water release to surface. In view of the latter, carefully designed baseline studies must be completed prior to moving ahead with this or other similar proposed schemes. This will require clear surface water quality and quantity objectives, inclusive of NORM.

4. Water Quality

4.1. Background

Concern over water quality was raised by several experts, including representatives who spoke on behalf of Treaty 8 First Nations, environmental consultants, academics, government staff, and ENGOs. The range of issues raised was quite broad, based on evidence spanning traditional knowledge through scientific data, and encompassed both groundwater and surface water.

This section focuses on water quality specific to contamination from hydraulic fracturing fluids and wastewater. Impacts to groundwater quality related specifically to gas migration and well integrity are discussed in Section 6.0.

There are several potential risks to water quality that are associated with hydraulic fracturing. First, is the potential for contamination of surface water and shallow groundwater from surface releases such as spills and leaks; second is the potential for contamination of shallow groundwater from underground sources, such as hydraulically fractured zones and wastewater disposal zones; and third is the accumulation of toxic and radioactive elements in the soils and sediments near sites that have been contaminated. Water quality in NEBC ultimately is vulnerable to contamination. The likelihood of spills and leaks occurring is likely no different than in Alberta or anywhere else, but the potential for those leaks and spills to lead to contamination of water could be significantly lower (or higher) than elsewhere simply because of differences in the physical environment (e.g. soil permeability, topography), the regulatory requirements and enforcement, and industry best practices. The potential for contamination of shallow aquifers from deeper sources as well as the accumulation of toxic and radioactive elements will also reflect a combination of these factors. To properly assess risk, data are needed to establish the likelihood of contamination of water (i.e. the hazard threat) as well as the potential consequences (e.g. to human or ecosystem health). As mentioned in Section 2.6, there are insufficient data to assess risks to human and ecosystem health. In the absence of data, the best that can be done is to make inferences on the potential risk-based understanding of the physical, chemical, and biological systems. Because shale gas development is a relatively recent activity in BC, as it is elsewhere, there has been much scrambling on the part of researchers, regulators, and government and non-government agencies to collect data. However, shale gas plays differ substantially from one area to another, as does jurisdictional regulation and policy. So, it becomes very difficult to make inferences based on studies carried out in other areas. As a result, the literature can be confounding, and it is unsurprising that the public feels misinformed or uninformed.

This section begins with a discussion of baseline water quality data. Then in the subsequent three subsections, threats to water quality are examined according to the three main sources or pathways of contamination: direct pathways from the deep subsurface to the surface; handling and storage of flowback water; and wastewater disposal wells. The section ends with a discussion of naturally occurring radioactive materials (NORM). Throughout, regulatory requirements or non-regulatory tools specific to the protection of water quality are reviewed where appropriate. Each subsection ends with recommendations.

4.2. Baseline Water Quality Data

4.2.1. Concerns Raised

Numerous concerns were expressed in relation to a lack of baseline water quality data, similar to those expressed in relation to baseline water quantity data (see Section 3.2). Overall, experts indicated that there is a lack of baseline water quality data across the region. Water quality data include major ions and physical parameters, as well as trace metals, NORM, and dissolved hydrocarbons and gases. Moreover, concern was expressed that our understanding of fate and transport of these various chemicals is not sufficiently developed or studied, nor the potential for such chemicals to cause harm to humans and the ecosystem.

This section discusses baseline water quality data at a regional scale. Specific baseline monitoring in relation to industry operations is discussed in Section 4.4.

4.2.2. Summary of Expert Evidence Presented

Surface Water Quality

The Panel had difficulty identifying experts on surface water quality in NEBC. Only one group of experts from Environment and Climate Change Canada (ECCC) could speak to baseline surface water quality. These experts summarized the key findings of the baseline water quality study and ecosystem health study in the Petitot watershed. This watershed was selected for baseline study because there is very low oil and gas development and the watershed is transboundary. Synoptic sampling was conducted at approximately thirty sites at four times to capture high and low flow conditions over two years (May 2013, Aug. 2013, May 2014, Aug. 2014). Sample sites were selected at micro-basin drainage outlets representing a range of upstream activity and potential contamination. Routine monitoring was also carried out at two sites on the mainstem (i.e. principal watercourse) and at three sites on tributaries at locations with known exposure to unconventional natural gas development (UNGD) and varying watershed areas. Biological monitoring followed sampling protocols established through the Canadian Aquatic Biomonitoring Network (CABIN) for benthic macro-invertebrate collections in streams and rivers (Environment Canada 2012)[37]. Aquatic biota, primarily benthic invertebrates are monitored because they have a 1-3 year life span and so are indicators of cumulative effects. Baseline reference conditions based on benthic macroinvertebrate communities and habitat

[37] CABIN: https://www.canada.ca/en/environment-climate-change/services/canadian-aquatic-biomonitoring-network.html

characteristics were established in order to develop a predictive CABIN bioassessment model to assess the ecosystem health of streams in the Liard, Fort Nelson, and Petitot River basins exposed to UNGD. Some outcomes of the study relevant to this review include: 1) Baseline water quality was established for the Petitot River watershed; 2) Synoptic sampling established existing conditions of UNGD and showed no evidence of surface water contamination in the Petitot River; 3) A representative long-term monitoring station was established for the Petitot River; 4) Benthic communities at sites exposed to UNGD were different than predicted but it is inconclusive if this is a development related effect; and 5) Inorganic indicators of shale gas development (e.g. barium) are not necessarily the cause of effects observed in the biological community. Contaminant composition of produced waters as well as the effect of climate and hydrological variation is needed to assess potential cause. In addition, the hydrology was quite different over 3 years; particularly 2012, which was a dry year; 2013 was a wet year; and 2014 was a normal year. With only 3 years of data, the results were inconclusive with respect to the potential impacts on aquatic habitat. The experts indicated that at least ten years of monthly physicochemical data are needed for trends, 15-20 years if sampled six times per year. Moreover, it is important to have regular monitoring to be able to separate out hydrology influences compared to development related influences. Some of the knowledge gaps identified include: limited water quality or biological monitoring data; limited groundwater and permafrost information; lack of information on the chemical composition of produced waters; and difficulty accessing water withdrawal information.

The Panel was given a brief overview of a Northeast Water Strategy study on surface water quality in NEBC. Water quality data for a wide range of parameters were found in the provincial Environmental Monitoring System (EMS) database and ECCC's CABIN database for 51 out of 69 watersheds, at 360 monitoring sites. Sampling dates range from 1971-2017. Priority watersheds for which there are no data include: Farrell Creek, Cameron River, Kyklo River, Doig River and the Upper Beatton River. No additional information was provided to the Panel.

The City of Dawson Creek carries out regular water quality monitoring of its drinking water supply – the Kiskatinaw River watershed – which it has been monitoring since the late 1990s. The city tests for a broad spectrum of chemical and physicochemical parameters. Currently, 17 sites are monitored. They have not observed any trends, with the exception of total organic carbon (TOC), which has been increasing in the Brassy sub-watershed, likely due to the large number of cattle. Turbidity in the Kiskatinaw River, the city's sole source of drinking water, is also elevated; it is the second most turbid river in BC. During spring freshet, the turbidity can be as high as 2,000 NTU (for comparison, BC drinking water guidelines suggest that a boil water notice should be issued when turbidity levels exceed 1 NTU). The city identified produced water pits in the watershed that are of concern, as are industrial chemicals and road salt. If there is a spill, and they lose their water supply, they may have 6 hours to 4 days of water.

Groundwater Quality

Groundwater samples are collected in the Provincial Observation Wells once yearly. However, only one water sample has been collected from a flowing well (#419) – this sample was collected when drilling was completed. Water chemistry appears to be stable from year to year, and is generally fresh with concentrations of major ions (e.g. chloride, sulphate, sodium, calcium) less than 150 mg/L. Because samples are only collected once per year, there is no information on how groundwater chemistry might vary seasonally. In the deepest bedrock well, #420, the water chemistry suggests an older, more mature composition, which can be expected due to its greater depth in comparison to the other wells in addition to its lagged response to recharge (discussed in Section 3.2.2). In well #286, the only well completed in unconsolidated sediments, water chemistry is normally fresh due to the influence of surface water, but in 2013 the major ion concentrations were somewhat elevated. The BC Regional Hydrogeologist for the Northeast explained that this well is influenced by pumping and is thus normally influenced by surface water, so that in 2013 when there was less pumping the water chemistry probably reflected the natural aquifer water chemistry. The variable chemistry results in any particular well thus represent a wide range of factors, and changes do not necessarily reflect impacts due to shale gas activities. Water chemistry data are available through the Environmental Monitoring System (EMS) database.

The NEBC aquifer characterization project began in 2011, and part of this project is the Private Wells Survey. To date, 393 locations have been sampled; these include primarily private wells, but also 47 springs, and four lakes. Prior to 2013, general groundwater chemistry was analyzed, including cations and anions, stable isotopes of water, and tritium. Analysis of dissolved methane was added in 2013/14, and carbon-13 and carbon-14 were added in 2014-15 along with additional dissolved gases (C_{1-4}, Ar, N_2, O_2, CO_2, H_2), total coliforms, and E-coli. As well, a total of 82 rain and/or snow samples have been collected since 2012 at two locations and analyzed for chemical and isotopic composition. In 2018, 24 wells showed elevated dissolved methane (> 10 mg/L); these wells were resampled to assess the potential sampling errors and natural variability; no results are available from this resampling. Data presented by the BC Regional Hydrogeologist indicate clustering of the isotopic compositions of the waters, which reflects the dominant ion chemistry of the source aquifer. Three water types were identified based on the major ion chemistry (NEBC 1: Quaternary aquifers; NEBC 2: bedrock aquifers, and NEBC 3: bedrock aquifers; note that bedrock aquifers show two distinct water types). The lowest total dissolved solids (TDS) groundwaters are the Ca-Mg-HCO_3 type (NEBC 1 as described above), and for wells that were cross referenced with the wells database (total 52) are consistently completed in the Quaternary sediment sand/gravel aquifers. The more Na-rich groundwaters are predominantly sourced from wells that are completed in the bedrock aquifers (NEBC 2 and 3). It is important to note, however, that these water type categorizations are somewhat uncertain because it has been challenging to cross reference the private wells with actual well records to verify the geological formation. All waters plot on or close to the meteoric water line suggesting recharge from precipitation, and moreover, recharge is predominantly derived from spring and winter precipitation, rather than summer precipitation (due to high evapotranspiration in summer that leads to minimal recharge). There is also evidence of evaporation in some lake samples, with no relation to the groundwater samples, indicating that lakes are not likely sources of groundwater recharge. Tritium concentrations for 250 wells (up to 2017) show that wells completed in Quaternary sediments generally have measurable tritium concentrations (up to 15 TU), reflecting their relatively younger age in comparison to bedrock aquifers, where tritium is typically below detection (i.e. 0 TU), suggesting an older water. The major ion chemistry is consistent with the tritium results, whereby younger waters hosted in Quaternary sediments typically have low concentrations of dissolved ions, while the older bedrock sources waters are more evolved.

In 2016-17, the BC Regional Hydrogeologist obtained access to 17 source wells (with good well logs) drilled in the Dunvegan Formation (Source Well Sampling Project). Wells were located along two transects to look at spatial trends between shallower aquifers and deeper aquifers. Calcium and magnesium concentrations were found to be negatively correlated to screen depth, which likely reflects the higher concentrations being associated with younger, shallower waters, while sodium was positively correlated to screen depth reflecting the higher degree of cation exchange in older, deeper waters. Dissolved methane concentrations were low (< ~0 mg/L) in wells with an average screen depth of less than 100 m, but methane concentrations were higher in deeper wells (~200 m). Isotopic fingerprinting has not been completed so it is unclear if the source of methane is thermogenic or microbial. To date, there is no report on the findings of this study.

The City of Fort St. John operates five wells that are situated close to the Peace River, such that the wells draw water from the river through the sand and gravel aquifer. The water is filtered and chlorinated. The city has been monitoring the water quality for 20 years; with 12 years of quarterly or annual testing. The wells require regular maintenance (mechanical and chemical) due to clogging (scale and sediment). The water quality in one well (#4) was very poor due to it being a bedrock source, so it was shut down. The hardness is elevated in another well (#1), so it is not used regularly. There is no evidence of bacterial contamination and there are no contaminants of concern, with the notable exception of elevated barium concentrations in 2005 (0.09 microgram/L) and 2017 (1.05 microgram/L). (For comparison, a Health Canada survey of barium levels in drinking water across Canada found a median concentration of 18 micrograms/L.). The area is designated as a groundwater protection area. The city has only 5 days of treated water storage.

In 2018, Geoscience BC, the BCOGC, and the University of British Columbia launched the Regional Groundwater Monitoring Program in NEBC. This program is still in its infancy, with only five or eight proposed background wells having been drilled to date. An additional twenty-two wells are to be drilled near oil and gas sites. The main goal of the program is to study gas migration in groundwater; however, the Panel could not find any detailed information on this project on Geoscience BC's webpage.

4.2.3. Other Evidence Considered

As mentioned in Section 3.2, over the period 2012-2015 Geoscience BC supported the Horn River Basin (HRB) Water Monitoring Study. The Panel briefly reviewed the summary report for this study (Kerr Wood Leidal Associates 2016). Discussion of the benthic invertebrate findings is provided in Section 7.2 on aquatic health. Five sites were monitored for water quality to determine if background levels of naturally occurring elements are above provincial water quality guidelines and whether site-specific water quality objectives should be developed. Key findings included: 1) several field parameters collected at each site (i.e. conductivity, TDS, and salinity) showed an increasing trend in concentration throughout the course of a year; 2) dissolved and total iron concentrations exceeded water quality guidelines for the protection of aquatic life at all sites for most sampling events; 3) total cadmium, chromium, and zinc concentrations exceeded water quality guidelines for the protection of aquatic life at two sites for the May 2014 sampling event, and at one site for the June 2014 sampling event; and 4) two sites have consistently high sulphate concentrations overall compared to the other sites. Overall, the authors state that the general trend of increased concentrations of field parameters observed in this water quality program during lower winter flows or low flow periods has been documented elsewhere. Seasonal fluctuations in chemical concentrations are a common phenomenon in most rivers, with lower concentrations during spring freshet and elevated concentrations during the low flow periods.

The Panel reviewed the key findings of a report on a Water Quality Database and Analysis for the Peace River Regional District (GW Solutions Inc. 2016). Data from 11,935 surface water samples from 364 locations, and 875 groundwater samples from 522 locations, going back to 1943 were compiled and compared to provincial and federal guidelines. A water quality index was used to compare water quality over selected time intervals, and maps were created to show spatial variations among watersheds. Sodium and sulphate increased in surface water (since 2000) and groundwater (since 2011); chloride increased in surface water (since 2000); higher concentrations of major ions were observed in bedrock wells since 2011; and barium concentrations in groundwater increased at several locations. However, trends over time could not be determined because the sampling locations were not the same. The study concludes that that the lack of information on water, both on quality and quantity prior to the 1970s, prevented baseline conditions to be characterized, and there is an absence of adequate temporal and spatial monitoring of both surface water and groundwater prior to and concurrent with human activities that may impact water. And finally, that there is a profound absence of knowledge about the presence and migration of fluids in the intermediate zone of the subsurface. The intermediate zone separates the hydrocarbon zones from the shallow groundwater zone, and in NEBC, is approximately located between a depth of 500 and 2,000 m.

The Panel reviewed a BC Water Science Series report by Baye et al. (2016) on the Dawson Creek-Groundbirch Areas of NEBC, to glean additional information on the groundwater chemistry results from the Private Wells Sampling Program. In total, water chemistry analyses were completed for 342 samples. Of the 342 groundwater samples collected across the Peace Region, 95 were quality assurance and quality control (QA/QC) duplicates or repeat samples from the same locations on different dates. Note the number of samples reported by Baye et al. (2016) is slightly less than the current number of 393 reported above given the different reporting period. Thus, approximately 87% of the groundwater chemistry results have been reported. At the time of writing of this report, the raw data for the Dawson Creek-Groundbirch study were available in the form of a MS Excel spreadsheet on the link to the report on the Water Science Series webpage. Given the concern about confidentiality of these data, the Panel is curious why ENV provided access to the raw data. The names of homeowners and the UTM coordinates were identified along with the chemistry results.

Groundwater quality in the study area was characterized through comparison to the Canadian drinking water guidelines, and through development of groundwater quality maps (Baye et al. 2016). The Panel notes that this groundwater chemistry study analyzed for dissolved constituents, not total concentrations, and as such, technically is not a water quality study. Dissolved arsenic was found to be the main health-based constituent of concern, with about 30% of samples exceeding the maximum allowable concentration (MAC) guideline of 0.010 mg/L. More than half of those samples had arsenic concentrations greater than 0.005 mg/L. It should be noted that the private well sampling protocol included field filtration of groundwater samples (Baye et al. 2016), and thus, higher arsenic levels could potentially occur in unfiltered groundwater, which may exceed the Health Canada maximum allowable concentration (MAC). Baye et al. (2016) report that visual inspection indicates groundwater samples with arsenic concentrations above the MAC do not occur more frequently in any area or aquifer type; high levels of arsenic occur about equally in unconsolidated (sand and gravel) aquifers and bedrock aquifer; and visual observation of arsenic levels do not suggest a dominant area of elevated arsenic. The authors conclude that the risk of elevated arsenic in groundwater appears to be relatively uniform throughout the study area. Several constituents have significant exceedances of aesthetic objectives (AO) guidelines, including iron, manganese, sodium, sulfate, total dissolved solids, and hardness. For example, groundwater TDS levels in the study area are high and about 85% of all groundwater samples had a TDS concentration exceeding the drinking water aesthetic objective (500 mg/L; Baye et al. 2016). Bedrock wells are moderately more likely to exceed the aesthetic objective for TDS (92%) than wells in unconsolidated aquifers (73%). Lower sulfate levels appear more prevalent in unconsolidated aquifers in the western portions of the study area, and high sulfate levels above the AO appear more prevalent in bedrock wells in the north-central and northeastern portions of the study area.

As discussed in Section 3.2.3, the BCOGC maintains a Water Portal. Within the Peace Region, there are roughly 1,400 records with surface water quality monitoring data that have been collected by different networks (including ENV, ECCC, Northern Health, and BCOGC). However, these are historical datasets with various periods of record; it is difficult to determine how many of these sampling locations are long-term monitoring sites (without looking in detail at the data). The Water Portal shows roughly 261 records for groundwater quality, and most are one-time sampling events at private wells.

One industry operator commented on the Water Portal as a means to communicate water quality data to the public, and identified that the Portal is missing translation of information (e.g. what is the difference between an exceedance of 0.5 mg/L, or what if there is a difference in concentration from one sampling round to the next – what does this mean?). If the intent of the Water Portal is to convey water information to the general public, then perhaps it is not the best place. Or, there should be funding for the translation component of data for public viewing. In addition, industry is required to sample basic parameters to get a construction permit for source wells under the WSA, but this information is submitted to BCOGC as a pdf, which defeats the purpose for easy data sharing. Alberta is currently working on trying to figure out how to extract those data from the pdf.

4.2.4. Key Findings

Regional baseline studies on surface water quality are lacking for NEBC, with the notable exception of the Petitot watershed study and the Horn River Basin study. Unfortunately, these studies were too short to provide any long-term information on trends. Analysis of available surface water and groundwater quality data throughout the Peace River Regional District by an independent consultant noted changes in chemical parameters, but whether these changes are indicative of trends could not be determined. The Panel acknowledges that other baseline surface water quality studies may have been conducted in the region (perhaps by university researchers in select watersheds), but no such studies were described by government agencies. Surface water quality monitoring data are few in number. Across the Peace Region, there are only about 1,400 records with surface water quality monitoring data with variable periods of record (accessed through the Water Portal). It was beyond the scope of this review to examine each record to determine how many sampling locations are long-term monitoring sites. An examination of BC's Water Quality webpage, refers the public to Federal/Provincial Water Quality Monitoring Sites hosted by ECCC. However, ECCC's webpage shows only one long-term water quality monitoring site on the BC-Alberta border. CABIN monitoring sites are, however, scattered throughout the Peace Region (the link to the interactive map was broken at the time of this review). Approximately 261 groundwater quality records are identified on the Water Portal, but most are one-time sampling events at private wells. At the present time, the Provincial Observation Wells sampling is insufficient due to the sparse distribution of wells and the annual resolution of water chemistry samples.

The cities of Dawson Creek and Fort St. John are carrying out regular water quality testing of their municipal water supplies. Overall, no trends have been observed.

The Private Well Study has been well executed and has provided critical information on the groundwater chemistry, thus significantly enhancing understanding of baseline chemistry, at least in the Dawson Creek-Groundbirch area (Baye et al. 2016). While not a comprehensive picture of the groundwater quality (note this study was not a groundwater quality study, but rather a groundwater chemistry study), the results have vastly improved knowledge of groundwater chemistry in at least one sub-region of NEBC. However, there remains a lack of information in other areas. Whether or not the chemical characteristics of the groundwater in the study area represent the groundwater chemistry elsewhere is not known. Limitations of the study include a lack of interpretation of the origin of the chemical constituents in the groundwater, and whether or not elevated arsenic or sulphate concentrations, for example, are a natural occurrence. Moreover, mixing is a dominant process in groundwater systems, and the water chemistry at any particular sampling point will often represent different groundwaters that have mixed along their flow paths. Thus, while it is possible to identify end-member types (e.g. NEBC 1, 2, 3), it is equally common that samples could show mixed chemical signatures. The Panel raises concern that the raw groundwater chemistry data for the Dawson Creek – Groundbirch study has been made public without removal of identifying information of located individual/private wells. This could represent a breach of confidentiality.

4.2.5. Recommendations

Long-term (i.e. permanent) surface water quality monitoring sites should be established to examine trends related not only to potential impacts from the oil and gas industry, but other industries, agriculture, and notably climate change. Understanding baseline and trends in surface water quality is paramount to the protection of the environment. Not only will this information be useful 20-50 years from now when BC has to ensure that the region is “cleaned up”, but in the short term, there is an opportunity for joint stewardship of the water resources that may serve to build trust, particularly if such a project could involve First Nations, members of the broader community, industry, and the BCOGC.

One recommendation from the Horn River Basin Study was to better characterize the surface water baseline and the observed chemical properties of the collected water for that program; a link to shallow groundwater and formation water chemistry monitoring program would be a good direction. To the Panel’s knowledge, this has not yet been done.

Surface water quality sampling should be carried out in the five priority watersheds identified in the Northeast Water Strategy report: Farrell Creek, Cameron River, Kyklo River, Doig River, and the Upper Beatton River.

The water quality sampling frequency in Provincial observation wells should be increased to seasonally, at a minimum, at least until the annual data can be placed within some natural range of variability. Additional wells should be placed in other areas of NEBC and in a diversity of hydrogeological settings (as mentioned in Section 3.2.5). These wells should be designed specifically for groundwater chemistry sampling rather than relying on private wells, for which it is difficult to cross reference to the well record. Placement of new Provincial observation wells should also consider different hydrogeochemical settings, so that perhaps samples of geological materials could be collected for whole rock geochemistry or for laboratory studies on geochemical processes. The suite of chemical analyses should perhaps be extended to include trace metal chemistry, gases, and other isotopes. Of course, the Province will need to commit resources if the Observation Well Network is expanded and additional sampling is carried out, because current resources cannot accommodate this expansion.

In relation to the Private Wells Study, the only reported results are contained within Baye et al. (2016) where 87% of the groundwater samples were collected. Broad generalizations of the groundwater chemistry were discussed in that report, but to further aid in comprehensive analyses, such as sampling in other regions or at different sites, a geochemical interpretation of the Private Wells Survey data is needed. It is the understanding of the Panel that such a report is in preparation, but every effort should be made to make this report available as soon as possible so that the scientific learnings can be shared more broadly. Moreover, while a visual spatial analysis of the data was carried out by Baye et al. (2016), a more rigorous geostatistical analysis should be completed. Such an analysis would enable government, researchers, the regulator, and the public to place the results of existing samples and future samples in context (e.g. does the Na concentration exceed the 95^{th} percentile?). Currently, in Alberta, there is an effort to consolidate several existing groundwater databases. The objective of this study is to use the large domestic and industrial water well datasets to inform development of 3-D models that can predict groundwater quality across the province. More specifically the study aims to provide a scientific assessment of baseline aqueous and gas geochemistry data for Alberta groundwater in areas of past, present, and future energy resource development. A rigorous geostatistical analysis of groundwater quality for NEBC would also lay the groundwork for region-specific groundwater quality objectives. What is ironic, is that while NEBC has been criticized for lack of groundwater data, a fairly substantial groundwater chemistry database now exists due to the efforts of government, academia, and the well owners. This database rivals other groundwater chemistry databases in the province in terms of numbers of samples collected (such as the Gulf Islands), although the spatial density outside the Dawson Creek – Groundbirch areas remains low.

Answering questions related to transport and chemical reactions (e.g. mixing, ion exchange, etc.) with the natural system will require information on the mineralogy and the in situ conditions within the aquifer system (e.g. pH, temperature, Eh, etc.). Some form of geochemical modelling should be carried out to aid in the interpretation of the data. Ideally, groundwater samples should be collected from the intermediate zone to better characterize the deep groundwater chemistry. To the Panel's understanding, such studies have not yet been completed.

4.3. Direct Pathways for Vertical Migration of Hydraulic Fracturing Fluids

4.3.1. Concerns Raised

Concern was expressed by representatives who spoke on behalf of Treaty 8 First Nations and environmental consultants about the potential for contaminated fluids (including gas, although gas migration is discussed in Section 6) to migrate from oil and gas producing zones and contaminate shallow aquifers. This concern centres on the network of pathways (natural and anthropogenic) that exist throughout the subsurface, but which are largely unseen. Questions were raised such as "*Who is looking at the subsurface? I saw a Shell map that was very disturbing*. *Much is hidden from view, and this raises concern.*"

The Panel notes that while fluids can potentially move vertically upwards through geological layers, the presence of caprock units of low vertical permeability in combination with low hydraulic gradients are broadly recognized as deterrents to vertical migration. A direct pathway, however, might exist through interconnected fractures or along conduits such as faults and fracture zones or along poorly constructed wells. The pathway need not be vertical, but can be tortuous (as would be the case through a fracture network). The concern of direct pathways for fluid migration has been raised in several reviews and papers (The Royal Society and Royal Academy of Engineering 2012; Vidic et al. 2013; Canadian Council of Academies (CCA) 2014; Vengosh et al. 2014; Ryan et al. 2015; Canadian Water Network 2015; U.S. EPA 2016).

This section focuses exclusively on the potential for fluid migration of hydraulic fracturing fluids due to hydraulic fracturing activities. Section 4.5 focuses on fluid migration in relation to wastewater disposal. Section 6 focuses on pathways for gas migration.

4.3.2. Summary of Expert Evidence Presented

The BCOGC Hydrogeologist stated that "*while the concept of vertical migration of hydraulic fracturing fluids may remain a public concern, research suggests that, at the depths of hydraulic fracturing in BC, the potential for a pathway connection to the usable groundwater zone due to hydraulic fracture propagation is negligible.*" This statement was based on BCOGC data on hydraulic fracturing depths, 3-D seismic surveys, measured microseismicity, and hydraulic fracture propagation data, research on caprock integrity, as well as a selection of journal papers/reports briefly summarized in Section 4.5.3.

One hydrogeological expert who spoke to this issue agreed that the risk to shallow aquifers due to hydraulic fracture propagation is low in NEBC, and that it is more of an issue in regions where hydraulic fracturing operations are shallower (e.g. Marcellus). Based on his review of the literature, fractures generated during hydraulic fracturing generally extend less than 100-150 m from the wellbore (e.g. Fisher and Warpinski 2013); although in rare occasions can extend up to 500 m (Davies et al. 2013). Notwithstanding, the Panel notes that several industry experts discussed microseismicity and showed data that clearly indicated events occurring along deep faults. For example, the origin of a large seismic event in the North Montney was "*conclusively associated to a mapped fault*" and "*A hypothesized fluid pathway, believed to be unique, connected the hydraulic fracture to the faul*t." The Panel notes that other factors may still act as barriers to the fluid migrating through the intermediate zone (e.g. fault continuity, fault conductivity, pressure differentials for upward flow, etc.).

The groundwater expert from the Geological Survey of Canada presented results from two projects to assess the potential for fluid migration from the ~2 km deep hydrocarbon-rich Utica Shale and the McCully tight sandstone units to shallow aquifers: one in southern Quebec (Saint-Édouard area, Ordovician St. Lawrence Platform) which has never been commercially active, and the other hosting the active fields in southern New Brunswick (Sussex area, Carboniferous Moncton Sub-basin). The studies benefited significantly from datasets provided by industry. In the Saint-Édouard area, regional faults are present as defined by deep seismic data, and shallow and deep fracture sets are similar and related to the geological history of the area (Figure 12; Ladeveze et al. 2018). The three defined high-angle fracture sets are common to both shallow and deep units with similar characteristics such as fracture attitude and spacing. Ledeveze et al. (2018) state that for this reason and based on the regional geologic history, these fracture sets could be used as analogs for those within the intermediate zone for which little to no data are available. Geophysical logs and hydraulic tests in 11 shallow (~50 m) observation wells suggested that most open and transmissive fractures occur within the uppermost 60 m of the bedrock (Ladeveze et al. accepted)

Dissolved hydrocarbons (mostly methane) have been found in shallow groundwater, where they are ubiquitous and locally abundant. There is also clear evidence that some deep formation brines, in addition to old Champlain sea water, are migrating into shallow aquifers in the vicinity of one of these faults (Bordeleau et al. 2018). This saline groundwater is attributed to the regional groundwater flow coming from the Appalachians and discharging along this normal fault zone close to the St. Lawrence River. The depth from which the brine originates is, however, unknown, but should not exceed a few hundred metres, as there is no indication that deep thermogenic gas from the Utica Shale is currently reaching the surface, through this pathway or elsewhere in this region (Bordeleau et al. 2018). Overall, within the Saint-Édouard area, the existence of large-scale preferential flow pathways was not unequivocally ruled out, but was deemed to be unlikely. However, Ladeveze et al. (2018) state, "*due to the limitations of the observation methods and the near absence of data for the intermediate zone, the vertical extension of natural fractures, which represents a critical parameter for aquifer vulnerability, still remains elusive [in that region]. The comprehensive assessment of the caprock integrity should also be based on geomechanical properties of the different caprock units, on gas and groundwater geochemistry to provide evidence for potential upward migration and on the definition of potential hydraulic properties of fractures, fault planes and associated damage zones identified in the Saint-Édouard area, as well as their in situ hydrological conditions*."

The expert from the Geological Survey of Canada noted that in the New Brunswick study area, the intermediate zone does not seem to be affected by major brittle structures in the hydrocarbon field and adjacent area, but a fault zone located outside the producing field, at the basin margin, was found to bring hydrocarbons at or close to the surface. This specific region is currently being studied to understand the significance of brittle faults at basin-margins as potential natural escape pathways for hydrocarbons and its potential hydraulic connection with the gas field.

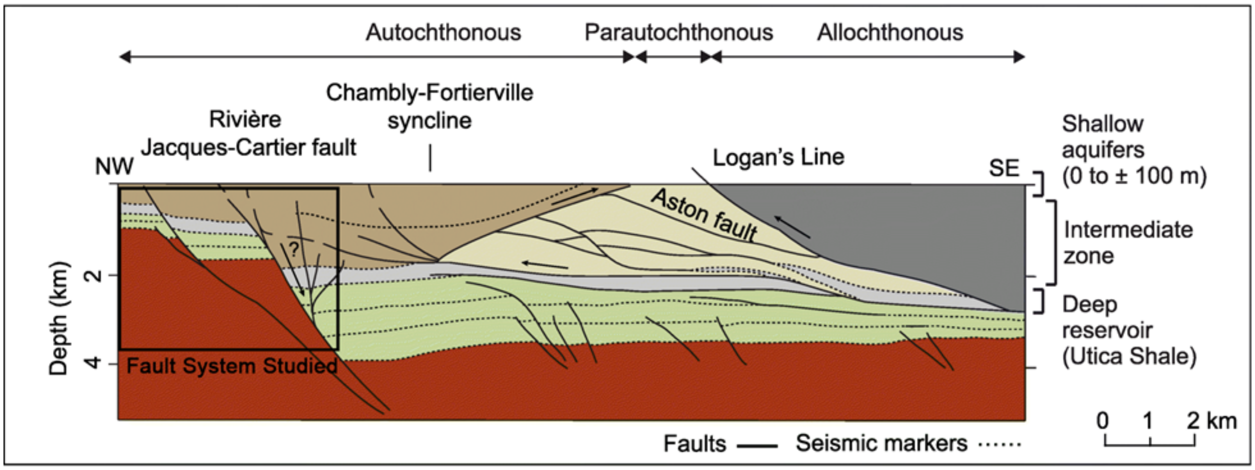

Figure 12. Structural cross-section of the study area in Eastern Canada to investigate the potential for upward contaminant migration along geological pathways through the thick intermediate zone located between a deep shale-gas reservoir (the Utica) and shallow groundwater aquifers. After Ladeveze et al. (2018).

4.3.3. Other Evidence Considered

To support this review, the Panel considered the broader scientific literature. The various reports/papers cited above, which have raised issues related to direct pathways, tend to focus on the potential for gas migration (i.e. The Royal Society and Royal Academy of Engineering 2012; Vidic et al. 2013; CCA 2014; Vengosh et al. 2014; Ryan et al. 2015; Canadian Water Network 2015; U.S. EPA 2016). However, the upward migration of hydraulic fracturing fluids and flowback water, and by association liquid phase hydrocarbons, is also considered therein and so is discussed here.

The context for upward migration of contaminated water described in the literature is generally in relation to hydraulic fracturing activities, or to natural processes, or both, and when related to hydraulic fracturing, is primarily due to the hydraulic fracturing process itself. Concern has been raised about the potential for fluids to migrate vertically upward to shallow aquifers through: 1) the pores and fractures in the thick layers of rock separating shallow aquifers from hydraulic fracturing zones; 2) fractures/faults (or direct pathways) that are opened up due to hydraulic fracturing activities; and 3) pre-existing faults (also direct pathways). There is also mention of 4) poorly constructed wells acting as conduits.

Vengosh et al. (2014) noted there has been considerable debate surrounding the potential rates of vertical fluid movement. Numerical modelling studies (e.g. Myers 2012; Gassiat et al. 2013; Kissinger et al. 2013; Birdsell et al. 2015a) suggested that the risk of upward fluid migration is low unless there are permeable pathways. Flewelling and Sharma (2014) found that hydraulic fracturing affects a very limited portion of the overlying bedrock and that the associated elevated pressures are short-lived and localized. Rutqvist et al. (2013) concluded that the possibility of hydraulically induced fractures at great depth (thousands of metres) causing activation of faults and creating new flow paths that can reach shallow groundwater resources (or even the surface) is remote. Flewelling et al. (2013) conclude that fracture heights are limited by the hydraulic fracturing fluid volume regardless of whether the fluid interacts with faults, and that direct hydraulic communication between tight formations and shallow groundwater via induced fractures and faults is not a realistic expectation based on the limitations on fracture height growth and potential fault slip. Since these "early" modelling studies, advances have been made in laboratory and modelling studies to understand processes; for example, the role of capillary imbibition and associated sequestration of fluid (Engelder et al. 2014; Birdsell et al. 2015a; Birdsell et al. (2015b). Reagan et al. 2015; Edwards et al. (2017) These studies found that no fracturing fluid reaches the aquifer without a permeable pathway and that factors not commonly included in model simulations can significantly influence modelling results. Thus, the presence of pathways appears necessary for vertical migration from fluid at depth to the shallow subsurface.

Geochemical evidence from northeastern Pennsylvania shows that pathways, unrelated to recent drilling activities, exist in some locations between deep underlying formations and shallow drinking water aquifers (Warner et al. 2012a), although there has been some debate concerning these findings (Engelder 2012; Warner et al. 2012b). The studies carried out in Québec and New Brunswick (above) also point to the potential for deep formation fluids to migrate up existing pathways. Similarly, other studies have shown evidence for cross-formational fluid flow of deep saline groundwater into overlying shallow aquifers, independent of oil and gas operations in the Michigan Basin (e.g. Weaver et al. 1995) and the Southern High Plains Aquifer in Texas (Mehta et al. 2000a; Mehta et al. 2000b). Based on a review of these studies, Vengosh et al. (2014) suggest that naturally occurring saline groundwater in areas of shale gas development poses challenges for quantifying contamination from active shale gas development, including the ability to distinguish naturally occurring groundwater salinization from anthropogenic sources of groundwater pollution.

In relation to well integrity, the U.S. EPA (2016) states, "*the relatively brief hydraulic fracturing phase will likely impose the highest stresses to which the well will be exposed during its entire* *life. If the well cannot withstand the stresses experienced during hydraulic fracturing, the casing or cement can fail, resulting in the loss of mechanical integrity and the unintended movement of fluids into the surrounding environment*." The U.S. EPA (2016) reported a few studies that have estimated rates of mechanical integrity failure of production wells resulting in the loss of all barriers protecting the groundwater or in contamination of groundwater in areas with hydraulic fracturing activity. The estimates are all approximately equal to or less than 1% of wells drilled or hydraulically fractured over varying timeframes, and for most of these estimates, it is not possible to tell whether failures occurred during hydraulic fracturing or at some other point in the well's life. The integrity of the well is influenced by its design and construction. To minimize mechanical failures, the surface casing should be placed from surface to the lowest depth of the drinking water source; the casing(s) should be fully cemented through the entire drinking water resource; and the well components need to be designed and constructed to withstand the stresses applied to the well (U.S. EPA 2016). In BC, drilling and production regulations under OGAA require this for all unconventional wells drilled in BC. However, the degradation and corrosion of well components can also increase the frequency of impacts to drinking water quality; older wells exhibit more problems as cement and casings age (U.S. EPA 2016). Hydraulic fracturing or re-fracturing older wells have the potential to increase the frequency of casing or cement failures allowing unintended fluid migration into drinking water resources (U.S. EPA 2016).

Nearby wells (often called offset wells) can be a pathway for fluid movement, with hydraulic fracturing fluid from one production well moving through the subsurface and entering another nearby oil or gas well or its fracture network; these events are commonly referred to as "well communication events" or "frac hits", estimated to occur 1% of the time (U.S. EPA 2016). The communication event might simply be registered as an increase in pressure in the nearby well, although there is also the possibility of damage to the nearby well or its components, causing a surface spill or a subsurface release of fluids. Nearby older or abandoned wells are of particular concern and thus can be a significant issue in areas with legacy (i.e. historic) oil and gas exploration wells (U.S. EPA, 2016). If nearby wells do serve as a pathway, fluids can bypass layers of intervening rock. In BC, Industry Recommended Practice (IRP #24) outlines a recommended hazard management process for mitigating the risk of inter-wellbore communication during hydraulic fracturing, including between older or abandoned nearby wells. BCOGC Industry Bulletin 2015-15 Reporting Inter-wellbore Communications outlines expectation for permit holders to follow IRP 24 and report instances.

4.3.4. Key Findings

The Panel did not see any evidence that shallow groundwater has been contaminated due to vertical migration of hydraulic fracturing fluid. That being said, no strong evidence was presented to the Panel to definitively rule out the possibility that hydraulic fracturing fluid could migrate vertically upward along pathways (e.g. along pre-existing faults or other wells) and contaminate shallow aquifers. Vengosh et al. (2014) raise an important point that the ability to trace and identify contamination from unconventional oil and gas development is limited, given the relatively short time frame since the beginning of large-scale shale gas development (i.e. since the early 2000s) compared to typical groundwater flow rates (on the order of decades). For this reason, there are not many studies to draw upon for evidence for this current review.

At the outset of this review, the Panel did not consider vertical migration of fluids to be an issue of concern. However, upon review of evidence provided by experts alongside a review of some of the most recent literature on the topic, the issue is not moot. Lefebvre et al. (2015) stated, "*To our best knowledge, no study has yet simulated the potential environmental impacts of hydrofracturing on aquifers with a full representation of all processes involved: multiphase system, density-dependent flow, reactive mass transport and hydromechanical effects.*" These authors also state that modelling using specific conditions of a given study area is necessary to assess if fluid migration is likely to occur along preferential paths, such as was done for southeastern Germany (Lange et al. 2013; Kissinger et al. 2013) or indeed more recently, in the Horn River Basin (Edwards et al. 2017). Lefebvre et al. (2015) point out that whether or not faults extend through the overlying shales is uncertain in some sedimentary basins as imaging of steeply dipping faults is intrinsically difficult with available seismic techniques. Moreover, obtaining such seismic data from industry has been an ongoing challenge for scientists, limiting the degree to which these structures can be meaningfully represented in models. While some authors (e.g. Flewelling and Sharma 2015) indicate that fractures in shales are often self-healing, regional-scale faults cross-cutting shale horizons are not just composed of shale, but rather could have complex fault architectures including fault cores, damage zones, etc. (e.g. Bense et al. 2013; Caine et al. 1996). Without detailed basin-specific data on fault zone hydrogeology it is difficult to establish the hydraulic continuity of a fault zone. Moreover, a major impediment for conducting robust modelling is the lack of comprehensive publicly available information and data about shale gas wells, the process of hydraulic fracturing, properties of the hydraulic fractures, and properties of shale formations (Edwards and Celia 2018). For this reason, Edwards and Celia (2018) recently compiled a substantial database to assist researchers in parameterizing their models. It is clear, therefore, that there remains considerable uncertainty in modelling results.

The potential for oil and gas wells (new or old) to act as conduits for vertical flow is also not fully understood. While current well design and construction standards and industry best practices, as well as monitoring and testing requirements during hydraulic fracturing, are likely adequate to mitigate risk associated with mechanical failure, the fact remains that old wells exist, and the design and construction standards were not the same in the past as they are today. Thus, while the risk of contamination from upward migration of hydraulic fracturing fluids to shallow groundwater aquifers is likely low, it is not zero.

The expert from the Geological Survey of Canada stated, "*One of the main gaps in our knowledge remains the Intermediate Zone.*" The vulnerability of shallow aquifers to contamination from activities with deep hydrocarbon reservoirs depends on the integrity of the intermediate zone, which can host vertical to sub-vertical fracture zones and faults that may act as conduits for fluid flow as reported by various scientific studies. Yet the intermediate zone appears to receive much less attention. The Panel notes that for near surface hydrogeological characterization, we benefit from surficial geology maps and lithology logs from domestic water wells, augmented in some areas by geophysical survey data (such as the SkyTEM survey conducted by Geoscience BC west of Fort St. John (Aarhus Geophysics ApS and GEUS 2017), or land-based geophysical surveys and shallow borehole geophysical logs (these include industry natural gamma logs that have been corrected for the effects of surface casings (Petrel Robertson Consulting Ltd. 2015; Best and Levson 2017)). These near-surface datasets provide data down to perhaps a few hundred metres depth below ground surface. In the deeper subsurface, proprietary data from 3-D seismic surveys and microseismicity datasets acquired during hydraulic fracturing and wastewater disposal, along with other (accessible) data, such as well logs, core, drill stem tests (DSTs), etc., provide a wealth of information that is used by industry to explore for and develop reservoirs. Such datasets were made available to researchers from the Geological Survey of Canada to carry out the studies in Quebec and New Brunswick, and significantly enhanced their ability to characterize the deep subsurface.

4.3.5. Recommendations

Understanding the potential for fluid migration upward from depths where hydraulic fracturing is taking place to the shallow groundwater zone demands an interdisciplinary approach, integrating a variety of datasets. It is clear that studies based solely on modelling are not sufficiently robust, given that issues continue to be debated in the literature.

Representatives who spoke on behalf of Treaty 8 First Nations and environmental consultants expressed the need for subsurface mapping, which would not only provide a view of the cumulative impacts in the subsurface, but which could also aid in identifying potential pathways for fluid migration. According to one environmental consultant, such mapping has been done for the Montney Formation in Alberta.

A comprehensive analysis of the potential for vertical fluid migration along pathways should be conducted. To the Panel's knowledge a study of this nature has not been conducted in NEBC. Such a study could make use of available well logs and core data collected from formations above the Montney, and supplemented by DSTs in select formations. An emphasis should be placed on data collection / analysis near (or within) fault and fracture zones, so that these may be better characterized. Infrastructure (i.e. industry wells and private domestic water wells), along with natural geological features (geological layers, faults, fracture zones) should be included to fully characterize the intermediate zone.

Permit holders are allowed to conduct hydraulic fracturing operations to depths of close to 600 m without additional permit conditions. At present, however, formations being targeted are more than 2,000 m deep. As future knowledge regarding the Base of Usable Groundwater and hydraulic fracture propagation distances is developed, a review of this prescribed depth limit may be advisable (Ernst and Young 2016).

4.4. Handling and Storage of Flowback Water and Produced Water – Leaks and Spills

4.4.1. Concerns Raised

Concern about leaks and spills of contaminated water and potential impacts on water were clearly expressed to the Panel by representatives who spoke on behalf of Treaty 8 First Nations, environmental consultants, and ENGOs. Large volumes of contaminated water are handled and stored at or near the ground surface on or near well pads, along transport routes, and at facilities. These waters include hydraulic fracturing fluids used for hydraulic fracturing activities, flowback water, and produced water. Recent comprehensive reviews of hydraulic fracturing (e.g. Vengosh et al. 2014; CCA 2014; U.S. EPA 2016) identified the contamination of surface water and shallow groundwater from spills, leaks, and/or the disposal of inadequately treated shale gas wastewater (disposal is discussed separately in Section 4.5) as a major concern.

The main pathways by which chemicals associated with hydraulic fracturing can enter natural waters are from accidental surface releases at shale gas pads where the chemicals are stored and used in operations, or along transportation route (CCA 2014). Flowback water that arrives at the surface during and after hydraulic fracturing is another source. This water is handled and stored (and often recycled) at the pad and is only removed when hydraulic fracturing operations are completed. This water is very saline and contains hydraulic fracturing chemicals and other types of natural contaminants (CCA 2014). The CCA report panel carried out an examination of publicly available information on this topic and found that groundwater impacts have been researched and assessed only minimally and that government and academia have also paid little attention to this category of impact. That panel noted that in most, but not all areas, shale gas development is too recent to produce clearly attributable contamination.

In the U.S., impacts on groundwater and surface water resources from current and historic uses of lined and unlined pits, including percolation pits, in the oil and gas industry have been documented (U.S. EPA 2016). Spills and releases of produced water with a variety of causes have been documented at different steps in the production process. The causes include human error, equipment or container failure (for instance, pipeline, tank, or storage pit leaks), accidents, and storms. The U.S. EPA estimated half of the spills are less than 1,000 gal (3,800 L), although a small number of much larger spills has been documented, including a spill of 2.9 million gal (11 million L) (U.S. EPA 2016, p. 7-1). Both short- and long-term impacts to soil, groundwater, and surface from spills have occurred, but for many spills, the impacts are unknown. The potential of spills of produced water to affect drinking water resources depends upon the release volume, duration, and composition, as well as watershed and water body characteristics (U.S. EPA 2016).

4.4.2. Summary of Expert Evidence Presented

In BC, wastewater management is regulated under EMA. EMA provides the regulatory framework for all discharges to the environment. It is primarily provincial legislation that governs the introduction of wastes into the environment. There are four relevant Regulations under EMA: the Oil and Gas Regulation; Hazardous Waste Regulation; Spill Reporting Regulation; and Contaminated Sites Regulation.

Spills and Leaks

OGAA also has specific requirements. Section 37 of OGAA contains requirements to prevent, report, contain, and eliminate spillage as well as to remediate land or water affected by spillage. Specifically, a permit holder must prevent spillage and promptly report to BCOGC any damage or malfunction likely to cause spillage that could be a risk to public safety and the environment. If spillage occurs, operators must promptly remedy the cause or source; contain and eliminate; remediate; and report to BCOGC. A person who is aware that spillage is occurring or likely to occur must make reasonable efforts to prevent or assist in containing or preventing the spillage. The BCOGC has a guidance document "Management of Saline Fluids for Hydraulic Fracturing" that was last updated in February 2016. It provides an overview of requirements under the DPR. Section 51(5) of the DPR requires that any earthen pit used to store saline fluids be designed and installed under the supervision of a professional engineer and approved under an OGAA facility permit. Section 51(6) of the DPR sets out requirements for lined containment systems used for the storage of saline fluids. In addition, Section 10 of the Environmental Protection and Management Regulation (EPMR) prohibits those conducting oil and gas activities on top of an aquifer from causing any material adverse effect on the quality, quantity, or natural timing of flow in the aquifer. Section 12 of the EPMR prohibits the deposition of deleterious materials into a stream wetland or lake.

Specific to above ground storage, the supervisor for environmental management at BCOGC described a range of above ground storage structures: c-rings, panel style above-ground walled storage systems (AWSS), and minion tanks. All require a facility permit under OGAA and are subject to review and decision. There are numerous enforceable conditions on permits to mitigate potential for impacts. Specific to containment facilities (e.g. below-ground flowback ponds), there are permit requirements for liners – minimum liner requirements and QA/QC; leak detection and monitoring requirements; leak reporting requirements; minimum safety factors for stability analysis; engineered design and engineering oversight of construction; wildlife access mitigation; groundwater monitoring; and site investigation upon decommissioning. At the time of the Panel Proceedings, there were 42 active containment ponds in NEBC; nine others were on the decommissioned list (the Panel had a site visit to four of them): one was inactive but not yet decommissioned, and two others had submitted applications. These vary in size from 136,000 m^3 to 300,000 m^3, with the largest one being in the HRB due to limited water availability in the region. Figure 13 shows an example of a containment pond.

Figure 13. Containment pond for produced water. Arial view (left) and close-up view (right) showing overhead and perimeter protection. Photos taken during the Panel's site visit.

The expert from BCOGC stated that synthetic liners are susceptible to various modes of failure: physical liner damage, welding deficiencies, and stress cracking. Multiple liners allow flexibility to eliminate or mitigate impacts from liner failures. Studies that have looked at liner damage have found that most are due to welding deficiencies discovered shortly after filling. In NEBC, two of the 42 active ponds were of older design and had to have the liners pulled – both had negative leakage results. In total, 8 or 9 containment ponds have had their liners removed – 3 had leaks, one of which was damaged by a suspected meteorite impact. At two of the four dual-lined tailings ponds that were found to have leaked at one decommissioned site (C-83-I and 94-B-1), the leakage occurred within the first year of operation; BCOGC considered it is possible that the operations crew never clearly received instruction from the construction crew that they had to regularly monitor – thus, there was a delay in responding to the active monitoring requirement. Moreover, while interstitial monitoring was carried out, no sub-drain was installed in these ponds. (If the interstitial seepage is found to be fresh water it means the lower liner has failed, while if saline water is found the upper liner has failed). BCOGC levied an administrative penalty ($30,000) to the permit holder. Site C-83-I is located on a local topographic high with fractured shale bedrock near surface. There are two creeks between 300 and 500 m away, and the nearest domestic water well is 3.74 km away. A total of 4,600 m^3 of impacted soil was removed, and 63 monitoring wells were installed. The highest chloride concentration measured in a monitoring well was 2,100 mg/L. The site was modelled for risk to receptors, and a remediation plan was developed and reviewed. In addition, BCOGC stated that there have been some events of leakage at 20 sites still in operation and one of these had leakage detected under both liners.

The Panel asked various operators about their experiences with liners. One operator carried out a post-use evaluation of its wastewater ponds and did not see any impact that went past the clay base, but leakage was detected in between the liners. The company had seen an increase in vault volumes and they pulled the liner to find pin holes in the liner. Another company stated, "*some companies have not got it right and have had leaks; there is technology out there and there needs to be strict adherence to how to install and monitor properly*."

Industry representatives described to the Panel their efforts to mitigate the impacts of spills and leaks, and their spill response protocols. Risk due to spills on drill pads is considered low because there are people and equipment readily on hand to respond quickly. The pads generally are at some distance from houses and, as described below, baseline groundwater monitoring is recommended by the Canadian Association of Petroleum Producers (CAPP) and is followed by many operators. Groundwater monitoring wells are not required at well pads, just at facilities. One representative of a company described the company's spill prevention principles related to fluid transfer, operational procedures, equipment integrity, and site design. They carry out regular emergency response exercises and drills; inspect, test and maintain equipment; follow procedures for spill prevention; and use best practices for facility and pipeline design. Well-known risks include leaks from tanks, hoses, and connections, which are mitigated through berms and drip trays. Specific to hydraulic fracturing is local erosion of pipes, which are mitigated by ultrasonic testing, velocity controls, and check-and-replace protocols. A representative from another company explained the company's two pronged approach in relation to spills and leaks: barriers and mitigation. The company embeds vulnerability of groundwater with decision making and plans proactively. A pad will be moved or the design altered; liners are used under all pads; the employees do "rounds of purpose" to look for evidence of spills or leaks. There is a comprehensive in-house reporting system for spills of all sizes. If there is a major release, there are protocols in place to remove the source and remediate. If there is a small release (drips), the source is removed and a risk assessment protocol is followed. A remediation team follows drilling a year later, evaluates the potential for adverse effects, and reclaims the pad at end of life of the well. The expert stated, "*this only works if you have a healthy reporting culture. But, there is not a long history in BC in developing this culture*." Finally, one industry representative considered spills and leaks related to pipelines and trucks to be more risky compared to spills and leaks on well pads. Thus, the Panel infers that as the use of recycled produced water increases, the risk of groundwater contamination from a truck or pipeline spill would likely increase as well.

Baseline Monitoring - CAPP recommends that operators carry out baseline sampling of groundwater from private domestic wells within a 250 m radius prior to initiating any drilling activities. CAPP indicated that most CAPP operators follow these best practices; pre-sampling is normally done, but post-sampling often is not. At least one industry operator currently exceeds this recommended practice. Since 2011, that operator has carried out baseline groundwater sampling within a 3 km radius of new wells. Twenty percent of wells are sampled every five years, so that all wells are sampled once every five years. Wells sampled include wells completed in surficial materials and bedrock wells. As part of this process, the operator walks through the history of the well with the well owner to discuss any changes over time. The results of the sampling are shared with the well owner, but are not released publicly. Based on results of re-sampling of wells in 2017, the industry expert in hydrogeology stated that there were no "significant" differences in groundwater chemistry between wells sampled in 2011 and the same wells sampled in 2017, except ferrous iron (Fe^{2+}) increased in all wells in 2015, but returned back to pre-2015 levels thereafter. In one domestic well, the barium (Ba) concentration was elevated above the Canadian Drinking Water Guideline; however, the Ba concentration was already elevated prior to sampling by the operator and was known to vary. This particular example is highlighted because elevated Ba concentration in this well was raised by an environmental consultant as being a serious problem. No other operators provided information to the Panel on background groundwater monitoring.

One major operator provided information on its groundwater monitoring network. The network includes five multi-level monitoring wells on each of nine well pads. Two wells are sampled for background conditions; one is considered low risk for contamination and the other is an inherited well off the pad. The decision on which well pads to monitor is based on a risk assessment – i.e. monitoring is carried out where the risk is assessed to be higher (the Panel did not delve into more details). One of the goals of the operator is to develop methodologies / technologies for monitoring. They have used different monitoring well designs (e.g. Westbay, multi-level standpipes). To date, they have not seen any significant concerns; i.e. there are no statistically significant differences in groundwater chemistry between monitoring wells and nearby domestic wells.

4.4.3. Other Evidence Considered

The Panel sought more quantitative information on spills and leaks in NEBC to supplement information provided by one industry operator. That operator suggested that over the past five years there were perhaps 20-50 reported spills. The Panel was not able to confirm this statistic. A U.S. EPA review of state and industry spill data indicated that the majority of the flowback water release incidents has been reported during its storage. About 46% by number of spills and 75% by volume of spills were related to failure of storage container integrity, according to the spill data for hydraulic fracturing flowback water from 2006 to 2011 (U.S. EPA 2015).

Ghandi et al. (2017) state that over 18 spills were recorded in the Montney in 2010 due to impoundment storage failure, although the authors do not provide the source for this statistic.

The BCOGC's Incident Reporting guideline outlines the systems and processes for reporting incidents. The Panel reviewed the regulation. Reporting of spills is regulated under the Spill Reporting Regulation under EMA. Waste oil (and similar) spills must be reported if they exceed 100 L. Produced water does not appear to be classified, but is assumed to fall under the category "a substance, not covered by items 1-23, that can cause pollution." The threshold for reporting produced water spills is 200 L. The Panel notes that thresholds for various forms of hazardous waste have much lower threshold reporting levels. For example, waste containing polycyclic aromatic hydrocarbons (PAHs) has a threshold of 5 L. Unfortunately the BCOGC's Incident Map (reported incidents) only shows the location of pipeline incidents.

Threats from spills and leaks can be greatly minimized by effective regulations. For regulations to be effective, however, there must be performance monitoring and sufficient inspections to ensure regulations are followed (CCA 2014). Although performance monitoring and enforcing regulations greatly reduce the risks of releases to groundwater, the risks are not entirely removed… spills happen.

A complicating problem is that not enough is known about the fate of the chemicals in the flowback and produced water to understand potential impacts to human health, the environment, or to develop appropriate monitoring or remediation systems. The CCA panel suggested that the risks due to surface activities will likely be minimal if proper precautionary management practices are followed.

4.4.4. Key Findings

The Panel considers the potential for leaks from containment ponds to be moderate to high based on the fact that two of four ponds that have been decommissioned to date were found to have leaked. In both cases, the ponds had dual liners. The interstitial monitoring program failed, and neither pond had sub-drainage. The nature of the fractured shale bedrock as a substrate beneath these sites was identified as problematic due to the jagged nature of the rock, which can pierce liners. The Panel raises concern about the integrity of liners, particularly in older containment facilities and those constructed on fractured shale, and the degree to which companies are doing their due diligence with regard to monitoring the interstitial space to assure there is no leakage.

In theory, the current regulations under both Acts, appear to be adequate to minimize risk to human health and the environment in relation to spills and leaks. It is noted, however, that significant amendments of the DPR were made as recently as July 2015, with changes to the Management of Saline Fluids guideline made in February 2016, so there is not a long track record to evaluate the performance of the new regulations. The regulations are broadly objectives-based, and detailed requirements are addressed through permitting. For example, sub-drains are now required, and according to BCOGC are now standard. Daily pumping of interstitial space must be carried out. BC regulation does not require three liners; although BCOGC reports that new ponds (~6-8 of them) have three liners. The Panel questions whether the minimum of four groundwater monitoring wells (one at each corner of a containment pond) is sufficient. One operator has 7-9 groundwater monitoring wells around each pit; these are sampled quarterly by a 3rd party and data are submitted to BCOGC.

The Panel found it difficult to judge the overall culture in relation to preventing and mitigating spills and leaks. Some of the larger operators appear to have clear and responsible protocols for spill prevention, identification and reporting, but whether this culture extends across the industry could not be assessed. Reporting of spills to BCOGC is only required for “large releases”, but cumulatively a series of “small releases” can result in the same volume over a period of time. Small spills can also lead to contamination of soil and water. Moreover, the thresholds for spill reporting seem somewhat arbitrary.

Overall, no groundwater monitoring is required except at facilities.

4.4.5. Recommendations

Monitoring around sites where hydraulic fracturing fluids, flowback and produced water are handled or stored should be enhanced. CAPP’s recommended best practices for baseline groundwater monitoring should be made a requirement in regulation. At the very least, monitoring of surface water and groundwater should be conducted downgradient of large above-ground storage tanks, containment facilities, chemical storage and fueling areas, and other related facilities.

CAPP recommends a risk-based monitoring strategy be adopted for shallow (potable) groundwater, whereby high risk areas are identified and mapped; targeted risk assessments are conducted (pathways identified, attenuation processes considered); regional monitoring is established to define natural water quality and variability; and concerns regarding cumulative effects are addressed. And, the results should be communicated to the public and stakeholder community via a suitable platform (e.g. Water Portal). The Panel concurs with this recommendation by CAPP. The Panel notes that water security maps have been generated for NEBC (Holding et al. 2018). These maps could be used as a starting point for developing a risk-based monitoring strategy. Quantitative risk assessment of leaks of various sizes is currently underway at Simon Fraser University. The modelling results are being reported in a format to show the relative risk for different soils and aquifer materials in graphical and map form.

Geochemical modelling to examine transport and fate of contaminants should be undertaken. This recommendation was made previously in Section 4.2.

The threshold for reportable spills should be re-examined by government, particularly given the inclusion of certain contaminants (e.g. PAHs) in produced water that are associated with hazardous materials with much lower reporting thresholds under the Spill Reporting Regulation.

While pipelines are considered to have a lower risk for transporting fluids, the potential increased risk due to the higher volumes of flowback and produced water transferred from/to site should be assessed.

In addition to reporting incidents related to pipelines, BCOGC should expand its website mapping interface to include all reported spills.

4.5. Wastewater Disposal

4.5.1. Concerns Raised

Concerns were expressed by representatives who spoke on behalf of Treaty 8 First Nations as well as environmental consultants and ENGOs on a number of potential impacts to water quality associated with wastewater disposal: 1) wastewater is not considered “hazardous waste” in BC; 2) there is potential for connection between disposal formations and shallow groundwater zones that may lead to groundwater contamination; and 3) disposal well integrity, particularly in cases where wells are re-purposed for deep injection. Industry also expressed concerns about a loss of injectivity related to the buildup of salts, such as barium sulphate ($BaSO_4$). This latter issue is of a chemical nature and so is briefly discussed here as it relates to concerns raised in Section 3.5 about disposal capacity.

The chemical composition of wastewater is variable depending primarily on the formation water’s chemical composition. In addition, wastewater contains fracking fluids. Wastewater is a brine with very high total dissolved solids dominated by sodium and chloride, as well as elevated concentrations of bromide, bicarbonate, sulfate, calcium, magnesium, barium, boron, strontium, radium, organics, and heavy metals (U.S. EPA 2016). It is noted that although naturally occurring radioactive materials (NORM) is commonly referred to in the context of wastewater disposal; NORM is discussed separately in Section 4.6 because NORM is not solely related to wastewater disposal.

4.5.2. Summary of Expert Evidence Presented

In BC, all wastewater is disposed of by injection into deep geological formations as discussed previously in Section 3.5. Deep disposal has been in practice for a long time in conventional oil and gas development, but as discussed in Section 3.5, higher volumes of wastewater are now being generated due to hydraulic fracturing. Moreover, in NEBC, concern has been raised about the long-term capacity of disposal formations. Thus, dealing with wastewater disposal is becoming an issue of growing concern.

In BC, disposal occurs at Produced Water Disposal Wells (PWDW) by primary producers, and in Non-Hazardous Waste Disposal Wells (NHWDW) by third party service providers. There is shared regulatory responsibility for management of wastewater. Wastewater disposal wells are regulated under EMA and OGAA. Section 7(1) of the Oil and Gas Waste Regulation authorizes the disposal of produced water or recovered fluids (wastewater) to an underground formation in accordance with the Oil and Gas Activities Act (OGAA). The BCOGC has delegated authority under EMA for facilities and operations for provincially regulated activities including the well (integrity, depth, flow) and the produced water (wastewater) disposal facilities, while ENV administers non-hazardous waste facilities and hazardous waste registration for PWDW and NHWDW. Non-hazardous waste covers waste materials that are not classified as "hazardous" under the Hazardous Waste Regulation. NHWDW are frequently referred to as Treatment, Recovery, and Disposal Facilities within the sector as they treat the incoming product to recover as much oil and other re-useable product from waste stream before disposal. Neither Canada nor the U.S. classifies wastewater from hydraulic fracturing as "hazardous waste", likely due to the long history of conventional oil and gas operations that permitted disposal of oil field brines. According to the expert on waste management from ENV, hydraulic fracturing wastewater does not strictly meet the criteria for classification as "hazardous waste" under BC's Hazardous Waste Regulation (e.g. flammable, caustic, corrosive) unless it is under pressure (i.e. the truck is not vented properly and the load gains pressure). Then the waste would be declared hazardous, and the onus is on the operator to register its load as hazardous.

In theory, the disposal of wastewater appears to be adequately controlled under EMA, Hazardous Waste Regulation, Oil and Gas Waste Regulation, Transportation of Dangerous Goods legislation and regulations, and appropriate manifests. However, the shared regulatory responsibility seems unnecessarily complicated. Permits for disposal facilities and wells are issued separately by ENV and BCOGC. The expert from ENV admitted that during the boom a few years ago, ENV was hard pressed to process permits and had a backlog of permit applications. The wait period could be up to one year, so producers were looking at other options, such as disposing wastewater in their own wells or sending it to Alberta for disposal. The expert from ENV also mentioned that the permit application process has recently been updated (Spring 2017). More information is now required and the application process[38] is more structured. ENV is currently examining permits for facilities to make sure they are all consistent.

While regulations stipulate that hazardous waste should not be downholed, it is up to the producer to declare that the waste is not hazardous. The expert from ENV on waste management indicated that ENV's Compliance Team carries out inspections of the facilities on a regular basis. An audit of the disposal well facilities is planned for 2020/2021 fiscal year. The

[38] BC Routine Application Process for Waste Discharge Authorization: https://www2.gov.bc.ca/gov/content/environment/waste-management/waste-discharge-authorization/routine-application-process

Panel notes that the last audit was conducted in 2013, at a time when hydraulic fracturing was not at its peak in NEBC.

The issue of vertical migration from wastewater disposal zones to shallow groundwater aquifers was not explicitly discussed by experts during the Panel Proceedings. Moreover, most published studies (as described in Section 4.3) focused on vertical migration from the hydraulically fractured zone. With the exception of the USEPA (2016) report, these reports do not speak to the potential for pathways between wastewater disposal formations and shallow groundwater. Notably, the evaluation of documented or potential impacts on drinking water resources associated with disposal at Class IID injection wells in the United States was outside of the scope of the U.S. EPA assessment (U.S. EPA 2016).

Similar to hydraulic fracturing zones, it is possible that wastewater could migrate vertically upward from disposal formations to shallow groundwater zones. Unlike hydraulically fractured zones which are very deep in NEBC, most disposal zones in NEBC are shallower. The BCOGC document on Water Service Wells (BCOGC 2018)[39] indicates that disposal formations are generally >800 m below ground level. Disposal wells in the Paddy-Cadotte Formation, for example, are roughly 1,000 m deep (Simons 2017). This effectively means a shorter vertical transport distance, and correspondingly shorter transport times compared to deeper hydraulic fractured zones. The potential for migration though geological layers in the absence of a pathway is considered to be minimal in NEBC, because vertical permeability is low and disposal formations "*must be shown to be contained by impermeable cap and base formations, competent to contain fluid within the area of influence*" as stated above. However, the Panel considers pathways for wastewater migration to be of the same general nature as those for migration from hydraulically fractured zones. The section Maximum Wellhead Injection Pressure in the BCOGC Water Service Wells document specifically states, "*Measured or inferred competency of bounding formations and wellbore cement are not criteria to inject above formation fracture pressure, as existing natural fractures, faults, planes of weakness and wellbores within the area of influence may provide migratory paths for fluids at a pressure below the formation fracture pressure.*" A similar statement is made in the section on 60-Day Pressure Value: "*While the wellhead injection pressure limit prevents formation fracture breach, injection operation can develop an area significantly above the final maximum formation pressure limit. Examples have shown that this zone of high pressure may be stored in a high permeability streak <u>extending some distance</u> from the disposal well. Assurance is required that this pressure will dissipate within the disposal zone. The higher the pressure, and longer the time to dissipation, increases the potential for fluids to find pre-existing migration pathways outside the injection zone, as well as remain a high pressure drilling or completion hazard*." The fact that the BCOGC acknowledges the potential role of permeable pathways suggests that these

[39] BCOGC (2018) Water Service Wells Summary Information: https://www.bcogc.ca/node/5997/download

present some risk in the context of wastewater disposal. However, currently there are insufficient data to assess this risk.

The Panel asked industry operators and the BCOGC about the integrity of disposal wells, particularly wells that have been re-purposed. One operator indicated that its first two disposal wells were re-purposed. They were closed off at the bottom and perforated higher up. BCOGC stated that if the purpose of the well changes, then it must meet the standards for that new purpose.

Loss of injectivity of disposal wells was raised by industry. In particular, the precipitation of barium sulphate ($BaSO_4$) was an expressed concern. One industry operator indicated that they have had problems with scale buildup on wells and have had to use acid treatment. The disposal wells are re-purposed wells that dispose of wastewater in the Debolt Formation. Service providers commented that they had to adjust their protocol for testing of wastewater when the water is received. If the water is "incompatible" (i.e. there is a potential for precipitation of salts or other chemical reactions with hydraulic fracturing fluid additives), then the wastewater is rejected for disposal. Mixing of water types (chemical compositions), therefore, can potentially lead to a loss of injectivity. At present, there is little understanding of chemical incompatibility of different waters. Given concerns about long-term disposal capacity in NEBC, this issue should be given attention.

4.5.3. Other Evidence Considered

In the U.S., hydraulic fracturing wastewater is mostly managed through injection (U.S. EPA, 2016); 93% of produced water from onshore wells was injected underground in 2012 (Veil 2015). So, BC regulations concerning the requirement for deep disposal are superior to those south of the border. Under federal law in the U.S., wastewater disposal wells are classified as Class IID (Disposal) wells. Class IID wells inject wastewater associated with oil and gas production underground and are regulated under the Underground Injection Control Program of the Safe Drinking Water Act. Carr-Wilson (2014) carried out some preliminary research to produce recommendations for improving how disposal wells are utilized in BC. This assessment showed that there are significant differences between the U.S. and Canada in how disposal wells are classified and regulated. As with their observations on the U.S. situation, the degree to which the current BC (and Alberta) regulations (including the permitting process) are sufficient to protect the environment over the long term is unknown.

In BC, for disposal well applications that are approved, the approval Order contains standard conditions for well monitoring and reservoir protection and, based on the hydrogeological risk review, may also include conditions for the protection of groundwater. In some cases, disposal well applications may be denied based on the hydrogeological risk review. Permit applicants must carry out a desktop hydrogeological review to document proximity to water supply wells, aquifers, capture zones, surface water bodies, surrounding land usage/occupancy, or other available information to assess groundwater use sensitivity. The BCOGC recommends using a tool "Groundwater Review Assistant" to aid in the review. This tool shows mapped aquifers, locations of groundwater well records, and well capture zones. The Panel noted that there are very few mapped capture zones.

Monitoring of shallow groundwater around wastewater disposal wells is only required if concerns are raised regarding wellbore integrity and/or groundwater sensitivity are identified, or if the top of the disposal zone is below, but within 100 m of the Base of Usable Groundwater. If the top of the disposal zone is shallower than the Base of Usable Groundwater determination, applications are denied. Specific requirements relating to the number of monitoring wells, locations, depths, sampling frequency, analytical parameters, and reporting are determined by the BCOGC on a case by case basis, based on well and site-specific information. Based on a Panel site visit to a service provider disposal facility, groundwater monitoring wells were placed at the edges of the property and are completed in the unconsolidated materials. No groundwater monitoring was conducted in the underlying bedrock.

4.5.4. Key Findings

While the design, construction, operating, and monitoring standards for wastewater disposal wells in BC are likely no different (and possibly tighter than for Class IID disposal wells in the U.S. – though a thorough review of the regulations and permitting process was beyond the scope of this review), public perception is that the wastewater that is being disposed of at depth is "hazardous" to human and environmental health, even though it may not be classified as such. It was beyond the technical capacity of the Panel to determine if the various criteria outlined as part of the permitting process are sufficiently robust to assure that disposal (facilities and wells) is being carried out with minimal risk to the environment. The degree to which permit requirements are met could not be determined, nor how rigorously the permit applications are vetted.

In NEBC, there is a general lack of information on groundwater, particularly the extent and thickness of aquifers, because there are very few groundwater well records that can be used to map aquifers with any degree of confidence. Typically, mapped aquifers in BC show the extent of the aquifer based on well data. If there are no data, then there is no mapped aquifer. This is especially problematic for bedrock aquifers that appear as isolated polygons surrounded by the same bedrock unit. Moreover, there are very few measurements of the hydraulic properties needed to characterize aquifers and map capture zones. Spring capture zones also do not appear on the Groundwater Review Assistant tool. Therefore, there are significant limitations to the Groundwater Review Assistant for assessing the sensitivity of groundwater systems in the vicinity of proposed wastewater disposal wells. The tool is a start, but requires a lot more data to be relied upon solely for a hydrogeological review.

The requirement for monitoring of the shallow groundwater system near a disposal well is at the discretion of BCOGC staff. No information was provided to the Panel on how often monitoring programs are required at disposal well sites or what they entail. The BCOCG Water Service Wells document examined during this review is dated November 2018. Edits to the document pertaining to Disposal Well Approval, Wellbore Integrity Logging, Horizontal or Highly Deviated Disposal Wells, Groundwater Monitoring Requirements were made as recently as July 1, 2017. So, there is limited history to determine the adequacy of these permit requirements.

4.5.5. Recommendations

There remains concern by representatives who spoke on behalf of Treaty 8 First Nations that hydraulic fracturing wastewater is not classified as hazardous waste. Government should carefully consider whether wastewater could be classified as hazardous in BC. From a public perception point of view, this change would acknowledge the potential hazard associated with wastewater and its disposal.

A review of the regulations and permitting requirements pertaining to disposal wells is recommended. Actual data from disposal wells across the region should be examined to assure that risk associated with fluid migration along pathways is being adequately addressed. In particular, this exercise would be useful given the new definition of the Base of Usable Groundwater.

Additional information and data on groundwater aquifers are needed to augment information on the Groundwater Review Assistant. As it stands, this tool is insufficient for a desktop analysis, particularly for bedrock aquifers in areas surrounding proposed disposal wells.

Baseline and ongoing testing of water quality near disposal wells is currently done on a case-by-case basis using permit conditions. Including these requirements in regulation and applying them more broadly would provide an additional tool to measure compliance with results-based regulatory requirements (Ernst and Young 2016).

4.6. Naturally Occurring Radioactive Materials (NORM)

4.6.1. Concerns Raised

Concern about naturally occurring radioactive materials (NORM) was expressed by several experts, including a toxicologist and a hydrochemist. Although NORM was not specifically mentioned by representatives who spoke on behalf of Treaty 8 First Nations, significant concern was expressed about wastewater disposal and why wastewater is not considered a hazardous waste given that it contains NORM.

4.6.2. Summary of Expert Evidence Presented

The toxicologist explained that NORM appear as mixtures and depend on the source formation and operation. Some degrade over time and the products may be different, so it is difficult to identify specific chemicals that may be associated with wastewater. Based on his research, NORM concentrations in flowback waters are highest in the southern areas of NEBC, and one recent sample showed radium-226 at 425 Bq/L; the Canadian Drinking Water Guideline has a maximum allowable concentration (MAC) of 0.5 Bq/L. This expert considered the extent and magnitude of NORM as a big challenge. The expert questioned the government's management plans for NORM. An expert in hydrogeochemistry similarly reported that radium-226 had been found at concentrations up to 425 Bq/L; radium-228 at 75 Bq/L; lead-210 at 10 Bq/L; and lead-212 at 15 Bq/L. He also noted that $RnSO_4$ can precipitate in pipes (along with $BaSO_4$ and other precipitates). The $RnSO_4$ is radioactively "hot" so if it is removed, there may be exposure. $PbSO_4$ has also been found in the sludge from flowback ponds, and if the pond is drained this precipitate would be in dry form and a health hazard. Both experts indicated that they were not aware of any studies on NORM in BC, and that generally there is a lack of water quality data in BC, specifically NORM concentrations. One expert suggested that a comparative study of NORM concentrations in the south (Montney) and north (HRB) could be conducted.

The expert from ENV on waste management spoke to NORM from a regulatory perspective. In BC, residual solids that contain NORM are sent to Saskatchewan for disposal in salt caverns. The presence of NORM is determined by the producer of the waste and the receiver checks for NORM. NORM thresholds are regulated federally.[40] If the producer or receiver determines that the waste is "too hot" then the waste is not accepted and must be treated or disposed of outside BC; there are no facilities in BC to treat wastewater for NORM. Records of how often waste was not accepted at a facility because it was too hot were not accessible to ENV staff because to their knowledge records are not kept. Records of the transportation of hazardous waste are called "Hazardous Waste Manifests" and are kept provincially by ENV. Currently, these are paper records and cannot be accessed electronically[41]. Another expert on water quality with ENV indicated that there has been a request by the NEBC offices of ENV about water quality guidelines for aquatic habitat specific to NORM. The expert did a search internationally and found none. He stated that water quality guidelines for aquatic habitat related specifically to NORM are on the "to do" list for ENV, but currently ENV does not have the resources to bump work on such guidelines to the top of the priority list.

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[40] Canadian Guidelines for the Management of NORM: https://www.canada.ca/en/health-canada/services/environmental-workplace-health/reports-publications/environmental-contaminants/canadian-guidelines-management-naturally-occurring-radioactive-materials-norm-health-canada-2000.html

[41] The decision of paper vs electronic rests with the federal Ministry of Transportation.

4.6.3. Other Evidence Considered

The geologic formations that contain oil and gas deposits also contain naturally occurring radionuclides, which are referred to as naturally occurring radioactive materials (NORM). These include uranium-238 and its decay products; thorium-232 and decay products; radium-226 and decay products (e.g. radon-222); potassium-40; lead-210; and polonium-210. Of these, radium is of particular importance owing to the presence of radium isotopes in all three natural decay series, the high mobility of radium in the environment under a number of common environmental conditions, and the tendency of radium to accumulate in bone following uptake into the body (International Atomic Energy Agency 2014). Health Canada (2010)[42] has established maximum allowable concentrations in drinking water for naturally occurring radionuclides.

NORM are present in the environment at relatively safe levels, but are often concentrated as a result of specific industrial processes. While uranium and thorium are not soluble in water, their radioactive decay products, such as radium, may dissolve in fracking water or produced water. NORM may remain in solution or settle out to form sludges that accumulate in tanks and pits, form mineral scales inside pipes and drilling equipment, or decay into a solid as a light dust. The concentration of radioactive substances in those materials may increase to levels at which special precautions are needed for handling, storing, transporting, and disposal of material, by-products, end-products, or process equipment (Tervita Corporation 2018). Because the extraction process for oil and gas concentrates the naturally occurring radionuclides and exposes them to the surface environment and human contact, these wastes have been classified as Technologically Enhanced Naturally Occurring Radioactive Material (TENORM) (US Environmental Protection Agency (U.S. EPA 2018)[43]. The possibility of ingestion or inhalation of these substances poses serious health risks for people and the environment, and can create costly liability issues.

Radium levels in the soil and rocks vary greatly, as do their concentrations in scales and sludges. Radiation levels may vary from background soil levels to as high as several hundred picocuries per gram (pCi/g), depending on the concentration of the radionuclide, the chemistry of geological formation, and the characteristics of the production process (U.S. EPA 2018). One industry study in the U.S. on NORM in produced water from conventional wells showed that the amount produced at any particular oil play depends on the factors above, as well as the age of the well (ICF Consulting 2000). The U.S. EPA (2018) noted, "*the volume of wastes from unconventional drilling can be much higher, since the length of the wells through the host*

[42] Government of Canada Guidelines for Drinking Water Quality: https://www.canada.ca/en/health-canada/services/publications/healthy-living/guidelines-canadian-drinking-water-quality-guideline-technical-document-radiological-parameters.html
[43] U.S. EPA TENORM: Oil and Gas Wastes: https://www.epa.gov/radiation/tenorm-oil-and-gas-production-wastes

formation can be over a mile long." The U.S. EPA is currently investigating the number of unconventional wells that are impacted by TENORM.

As NORM is not part of the nuclear fuel cycle, it does not come under the control of the Canadian Nuclear Safety Commission (CNSC)[44], which licences and controls radioactive materials associated with the nuclear fuel cycle and artificially produced radionuclides. NORM-related activities therefore fall under the jurisdiction of the provinces and territories. This has led to inconsistent application of radiation protection standards with numerous agencies involved as materials cross jurisdictional boundaries (Health Canada 2008). Therefore, Health Canada developed the Canadian Guidelines for the Management of NORM (Health Canada 2008)[45] to ensure adequate control of NORM encountered by affected industries, harmonize standards, and reduce jurisdictional gaps or overlap. These Guidelines appear to be very comprehensive. The basic principle of these guidelines is that where workers or the public are exposed to additional sources or modes of radiation exposure because of activities involving NORM, the same radiation protection standards should be applied as for CNSC regulated activities. This applies to situations where NORM is in its natural state and to cases in which the concentration of NORM has been increased by processing (Health Canada 2008).

BC has detailed waste acceptance protocols defined in the Hazardous Waste Regulation (HWR)[46]. Any waste that exceeds specified maximum concentrations cannot be disposed of in BC; this waste is disposed of in specialized hazardous waste facilities outside the province. A review of hazardous waste disposal information on the website of a third party waste disposal service provider, clearly states that an operator is "*responsible, and legally liable, for accurately verifying the specific constituents of the hazardous waste its operations has produced and shipped for treatment and disposal.*" Operators are provided with the appropriate forms that must be completed by an operator to determine if the waste(s) can be accepted and to assist in the analytical testing requirements for each waste stream or type[47]. Any material that exceeds the concentrations in Schedule 4, Table 1 of the HWR will not be approved for disposal in BC. In regard to NORM waste, this third party operator indicates that NORM concentration must be δ70 Bq/g and radium-226 at δ 5 Bq/g. It is unclear how these threshold concentrations have been defined as they do not appear in Schedule 4, Table 1 of the HWR.

In NEBC, sludge in gas pipelines from producing wells to the processing facility was found to have a mean lead-201 activity of 0.494 Bq/g and a mean radium-226 activity of 0.417 Bq/g (van Netten et al. 1998). These were gas pipelines, not wastewater pipelines, and so are not specific

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[44] Except for the import, export and transport of radioactive material.

[45] Canadian Guidelines for the Management of NORM: https://www.canada.ca/en/health-canada/services/environmental-workplace-health/reports-publications/environmental-contaminants/canadian-guidelines-management-naturally-occurring-radioactive-materials-norm-health-canada-2000.html

[46] Hazardous Waste Regulation: http://www.bclaws.ca/Recon/document/ID/freeside/63_88_00

[47] Tervita Waste Acceptance Protocols: http://www.tervita.com/solutions/challenge/waste-management-and-disposal/~/media/c5c48115175d40ab8a06aabc7838d40e.ashx

to hydraulic fracturing activities. The risk of radon and gamma ray exposure to a worker was deemed well below the occupational standards.

4.6.4. Key Findings

There is a significant knowledge gap on the extent and magnitude of NORM risk. NORM in wastewater is a particular concern. The Panel infers that concentration of chemicals, including NORM, in wastewater is becoming more concentrated, given that operators are increasingly recycling and reusing wastewater for hydraulic fracturing operations. Wastewater is stored on surface (in ponds, c-rings) and evaporates, further concentrating dissolved chemicals, and concentrations up to 425 Bq/L have been measured. There is also a high likelihood that chemical precipitates in pipes contain TENORM, which can be eroded by wind and become airborne. Such airborne particles are a known human health hazard.

Currently, it appears that much of the responsibility for testing for NORM in wastewater lies with the producer. The protocol for declining waste by third party service providers appears to be robust; however, the Panel is unclear what protocols are in place for disposal of wastewater containing NORM by producers.

Many operators in NEBC confirmed that adequate wastewater disposal is a growing concern for future operations, simply because the volumes of wastewater that will need to be disposed of exceed the current inventory of deep formations suitable for disposal (see Section 3.5). One major operator in NEBC is currently preparing an application to build a wastewater treatment facility that would distill the wastewater so that fresh water can be returned to the environment. While this is a promising step forward in reducing the wastewater footprint, the residual waste must be disposed of. What protocols are in place to deal with increased wastewater, and possible “hot” residue from distillation of wastewater? Are the NORM thresholds in BC in relation to the handling, storage and deep disposal of wastewater sufficient to protect the environment? Is there adequate capacity for treating or disposing an increased volume of hazardous waste (e.g. salt caverns in Saskatchewan) that could be associated with growth in the industry in the future, or towards the end of development when all the remaining wastewater needs to be disposed of?

4.6.5. Recommendations

The issue of NORM throughout wastewater cycle (storage facilities, pipes, solid waste) needs careful examination by government to determine if current practices are sufficient for protecting human health and the environment.

More research on NORM in waste and wastewater is required. Comparative studies could be carried out in different regions of NEBC to identify spatial variability of NORMs and identify high risk areas. In particular, there could be a focus on using fingerprinting techniques that employ radiogenic isotopes (Ra-226, Rn-222, and Pb-212). Ion ratios (e.g. B/Cl, Br/Cl, Li/Cl, and Sr/Cl) as well as a range of stable isotopes (™18O, ™2H, ™13C, ™34S, ™11B, ™37Cl, and 87/86 Sr) and noble gases should be targeted to support fingerprinting of produced water sources and groundwater sources.

5. Induced Seismicity

5.1. Background

Anomalous induced seismicity related to hydraulic fracturing and wastewater disposal is a key subject of concern expressed by representatives who spoke on behalf of Treaty 8 First Nations, environmental consultants, ENGOs, industry operators, industry groups, and the BCOCG. Environmental and public health and safety concerns range from the nuisance, destruction of the peaceful enjoyment of land, possible mental health issues arising from anxiety and/or fear resulting from felt anomalous induced seismicity, damage to critical infrastructure, and wellbore integrity issues resulting in a pathway for the transport of hydraulic fracturing fluids to shallow groundwater sources (see also Section 4.3). Various technical challenges were also expressed by industry operators, academics, and the BCOGC associated with susceptibility to anomalous induced seismicity, seismic hazard assessment, mitigation, and monitoring. A further discussion on risks to safety is included in Section 7.3. The term induced seismicity is used in this report to refer to all anthropogenic seismicity and a distinction is made between operationally-induced (i.e. expected microseismicity) and anomalous induced seismicity (AIS; i.e. larger magnitude and nuisance seismicity).

Anthropogenic earthquakes induced by oil and gas activities were first observed in BC in 1984 in the Eagle field area (Figure 14) resulting from water injection for enhanced oil recovery (EOR) (Horner et al. 1994). Thirty-five earthquakes with magnitude (M) 3 or greater have been linked to EOR in BC. Four of the earthquakes had M≥4; the largest, a M4.3, was recorded on May 22nd, 1994 and resulted in moderate shaking felt over an area as large as 2000 km^2 (Horner et al. 1994). Following the formation of the BCOGC in 1998, the injection rate allowed for EOR was systematically reduced, which has resulted in a decline in the frequency and magnitude of induced seismic activity, but occasional M≥3 earthquakes are still induced.

In January 2002, a well in the Graham area within the Montney Play (Figure 14) began disposal of wastewater into the Debolt Formation (Graham well) and on November 4th, 2003 the first AIS event was detected at this site. In the area surrounding the disposal well, 24 M≥3 earthquakes have been recorded, the largest a M4.0 on September 29th, 2010. However, the link between disposal and seismicity was not made until the seismic monitoring network was expanded in 2013. Although 129 earthquakes had been recorded in the area, no felt events had been reported, due to their remoteness, and the events were small relative to natural earthquakes. As a result of the seismicity, disposal into the Debolt was terminated in 2015. The disposal zone for the Graham well has since been the shallower Baldonnel Formation, and the frequency and magnitude of events has continuously declined. The last recorded event with M≥2.5 was a M2.7 on March 16th, 2018.

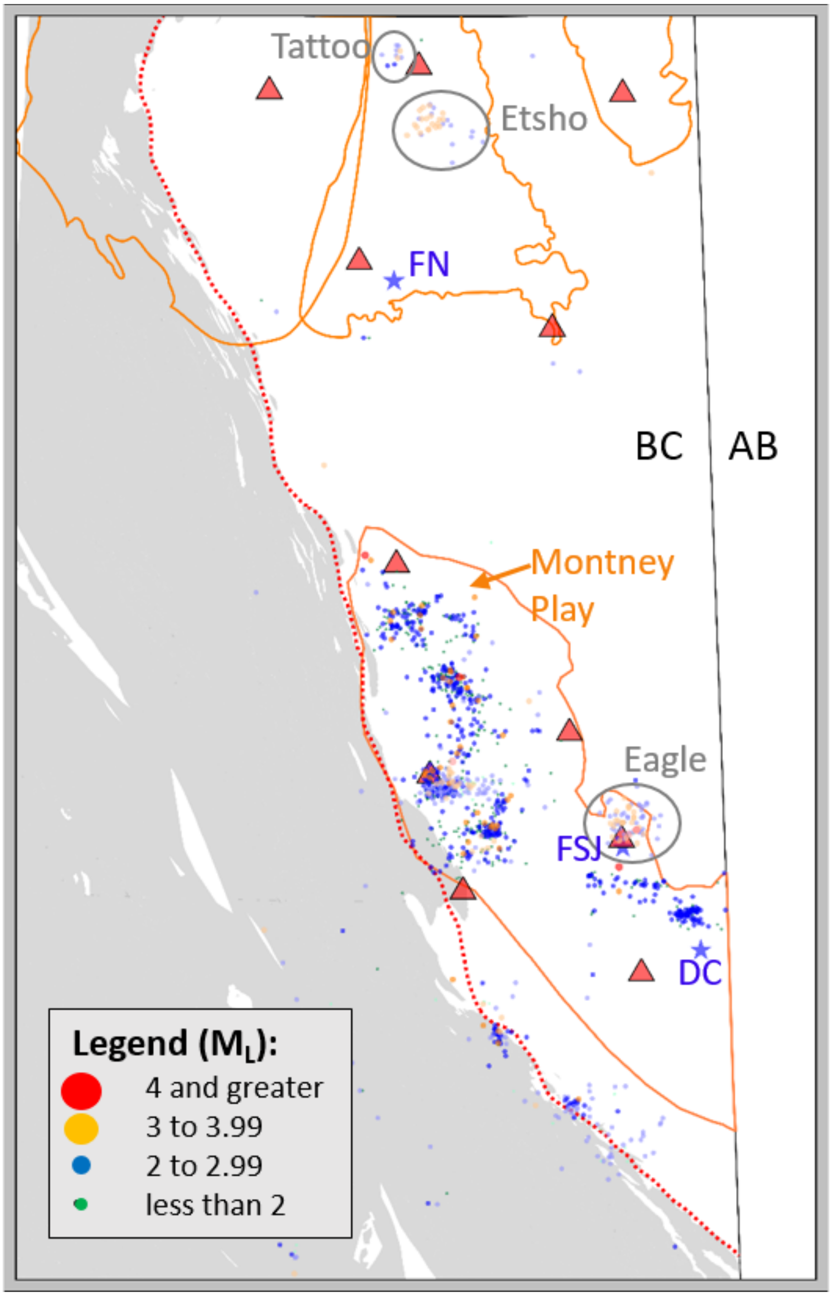

Figure 14. Recorded earthquakes in NEBC since 1985 from the NRCan database[48]. Red triangles show the locations of regional seismograph stations. Blue stars mark the locations of Fort Nelson (FN), Fort St. John (FSJ), and Dawson Creek (DC). Red dotted line delineates the eastern boundary of the Western Canada Sedimentary Basin. Source: BCOGC.

[48] Natural Resources Canada Earthquake Database: http://www.earthquakescanada.nrcan.gc.ca//stndon/NEDB-BNDS/bull-en.php

The seismic monitoring network in NEBC originally consisted of two stations, one near Fort St. John (Bull Mountain near Hudson's Hope) installed in 1998 and one in Fort Nelson installed in 1999. In 2013, six stations were added to the NEBC network by the BC Seismic Research Consortium. The Consortium was formed by the BCOGC and Geoscience BC the previous year following the BCOGC's investigation into the relationship between seismicity in the Horn River Basin and hydraulic fracturing. The report was the first in North America and the second worldwide that linked hydraulic fracturing to seismicity. Twenty-two induced earthquakes with M≥3 have been recorded in the Horn River Basin; the largest was a M3.8 on May 19th, 2011. Seismicity in the Horn River Basin returned to natural background levels in 2013 when industry stopped exploration and development activities and moved focus to the Montney Play.

In response to the anomalous seismicity induced by hydraulic fracturing operations in the Horn River Basin (Figure 14), BCOGC added permit conditions specifying shut-down of operations for M≥4 events and events with felt ground motions within a 3 km radius of the well pad. The permit conditions were put into regulations in 2015 as the seismicity in the Montney continued to increase and disposal wells were identified that were inducing anomalous events.

In 2013, the BCOGC began ordering the deployment of dense arrays in areas of active AIS in the Montney to increase hypocenter resolution and the minimum detectable magnitude. The BCOGC released a report on the seismicity in the Montney in 2014 and initiated a review of all disposal wells. The AIS was observed to form clusters; five clusters of events were linked to hydraulic fracturing (Figure 15). The Septimus and Doe-Dawson clusters were identified in the South Montney (S. Montney) and the Caribou, Beg-Town, and Altares clusters were identified in the North Montney (N. Montney). Two additional clusters, Graham and Pintail, were linked to waste fluid disposal in the N. Montney. It should be noted that some of the large scatter in events (Figure 15) is an artefact of the poor location resolution. The clusters in the S. Montney occur along strike-slip faults in the Fort St. John Graben, whereas clusters in the N. Montney occur on the eastern edge of the Rocky Mountain fold-and-thrust belt.

To increase the resolution of hypocenter locations in the Montney, two additional seismographs were added in 2014 and one more was added in 2016. In 2016[49], the BCOGC introduced permit conditions for operators within the two areas of known seismicity (i.e. N. Montney and S. Montney; Figure 15), requiring a ground motion monitor within 3 km of hydraulic fracturing operations and the reporting of events with ground motion of 2% g or greater or that are felt. BC is currently the only jurisdiction where the collection of near-field accelerograms is required. The reporting threshold was decreased to 0.8% g in January, 2018[50] to reflect the ground motions of felt events. The BCOGC also issued a Special Project order on May 14th, 2018[51], for hydraulic fracturing operations within the Kiskatinaw Seismic Monitoring

[49] BCOGC Guidance for Ground Motion Monitoring and Submission: https://www.bcogc.ca/node/13256/download

[50] BCOGC Industry Bulletin 2017-25: https://www.bcogc.ca/node/14678/download

[51] BCOGC Industry Bulletin 2018-09: https://www.bcogc.ca/node/14878/download

and Mitigation Area (KSMMA; Figure 16), requiring enhanced communication with residents, seismic hazard assessment and submission of monitoring and mitigation plans, a reduced threshold of M≥3 for the suspension of activities, a threshold of M≥2 for the activation of the mitigation plan, and the possible suspension of operations when clusters of events are induced.

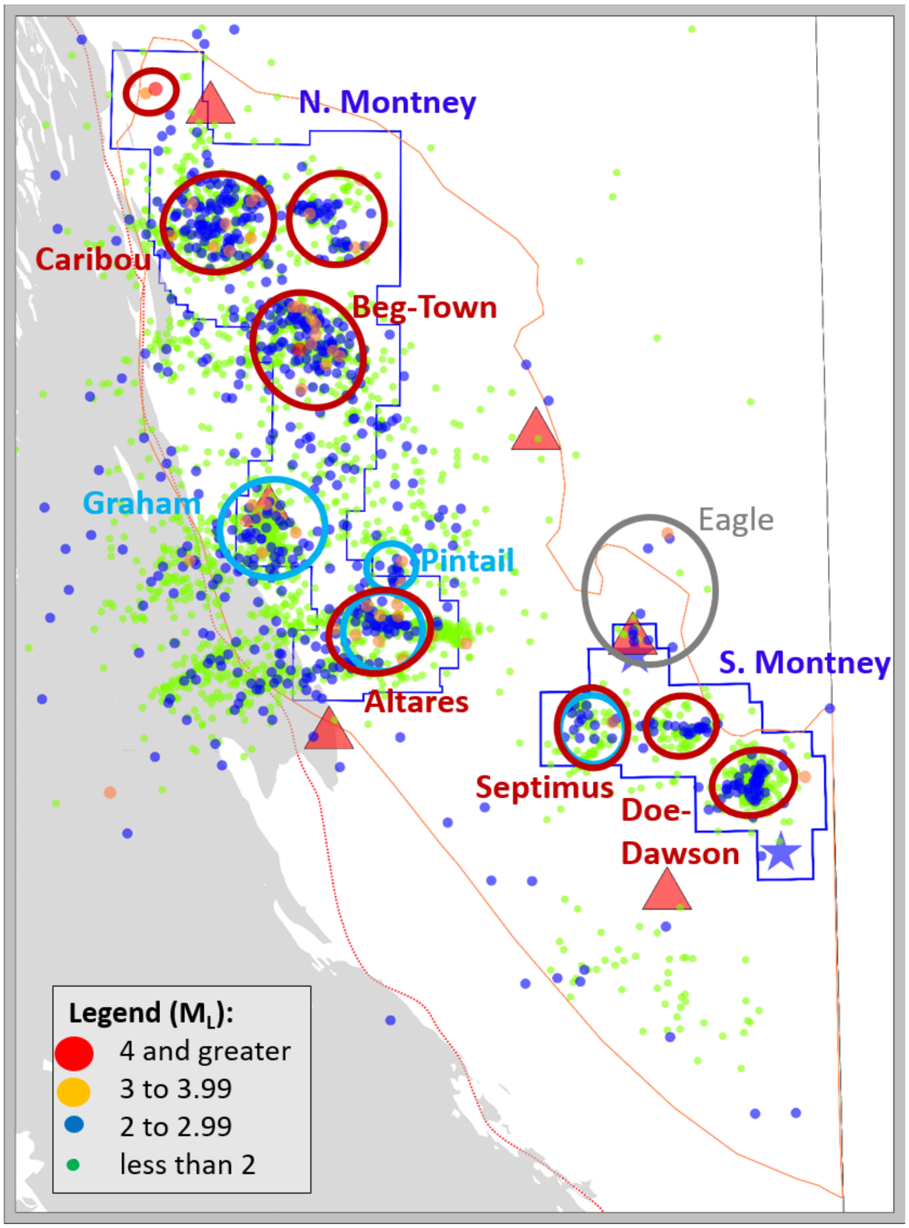

Figure 15. Recorded earthquakes in Montney Play (2014-2016) from the enhanced catalogue of Visser et al. (2017). The two areas requiring ground motion monitoring are outlined in blue (S. Montney and N. Montney). The clusters of events linked to hydraulic-fracturing are circled in red, clusters linked to disposal are circled in light blue, and the Eagle cluster linked to EOR is circled in grey. Blue stars mark the locations of Fort St. John (FSJ) and Dawson Creek (DC) and red triangles mark the locations of regional seismometers. Source: BCOGC.

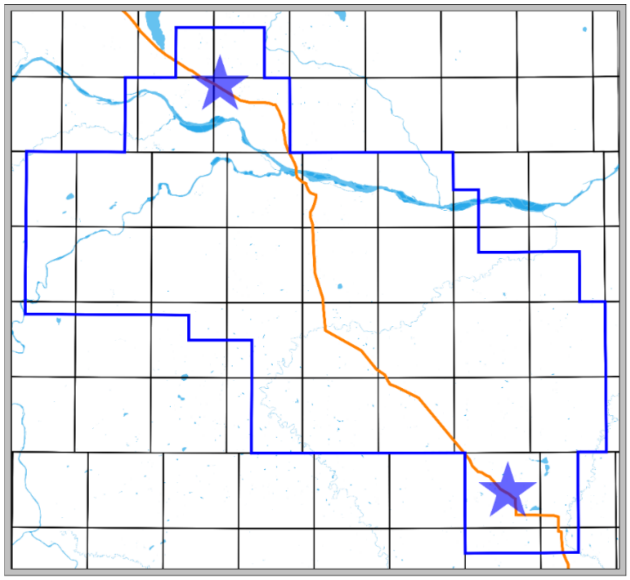

Figure 16. Map showing the location of KSMMA (area outlined in blue). The locations of Fort St. John and Dawson Creek are marked by blue stars. Source: BCOGC.

Since 1985, when monitoring stations were first deployed in NEBC, two natural earthquakes were recorded with M≥3, the largest was a M3.3 on May 2nd, 1992. This compares with 133 earthquakes with M≥3 that have been induced by fluid injection. Of these, hydraulic fracturing has been linked to 53 events with M≥3, fluid disposal has been linked to 35, and 10 events have been linked with both hydraulic fracturing and disposal (35 linked to EOR). Atkinson et al. (2016) calculated that 62% of earthquakes with M≥3 in the Western Canada Sedimentary Basin (WCSB) from <u>2010-2015</u> were induced by hydraulic fracturing, 31% were induced by wastewater disposal, and 7% were natural earthquakes (Figure 17). In contrast, only 8.5% of the earthquakes with M≥3 <u>prior to 2010</u> were induced by hydraulic fracturing and 82% were induced by wastewater disposal, while 9% were natural earthquakes. While hydraulic fracturing operations in BC and AB sharply increased in 2010, the increase in disposal wells has been more steady, likely resulting in the observed reversal (Atkinson et al. 2016).

With respect to spatial distribution, sixty-five of the events with M≥ 3 occurred in the N. Montney, 35 in the Eagle field, 22 in the Horn River Basin, and 8 in the S. Montney. Ten events have been recorded with M≥4. Four of these were in the Eagle field, three in the N. Montney, and three in the S. Montney. One of the M≥4 events in the N. Montney was linked to disposal and the cause of one event in the S. Montney is linked to both disposal and hydraulic fracturing. The largest recorded event was a M4.6 on August 17th, 2015 induced by hydraulic fracturing in the Beg-Town area in the N. Montney.

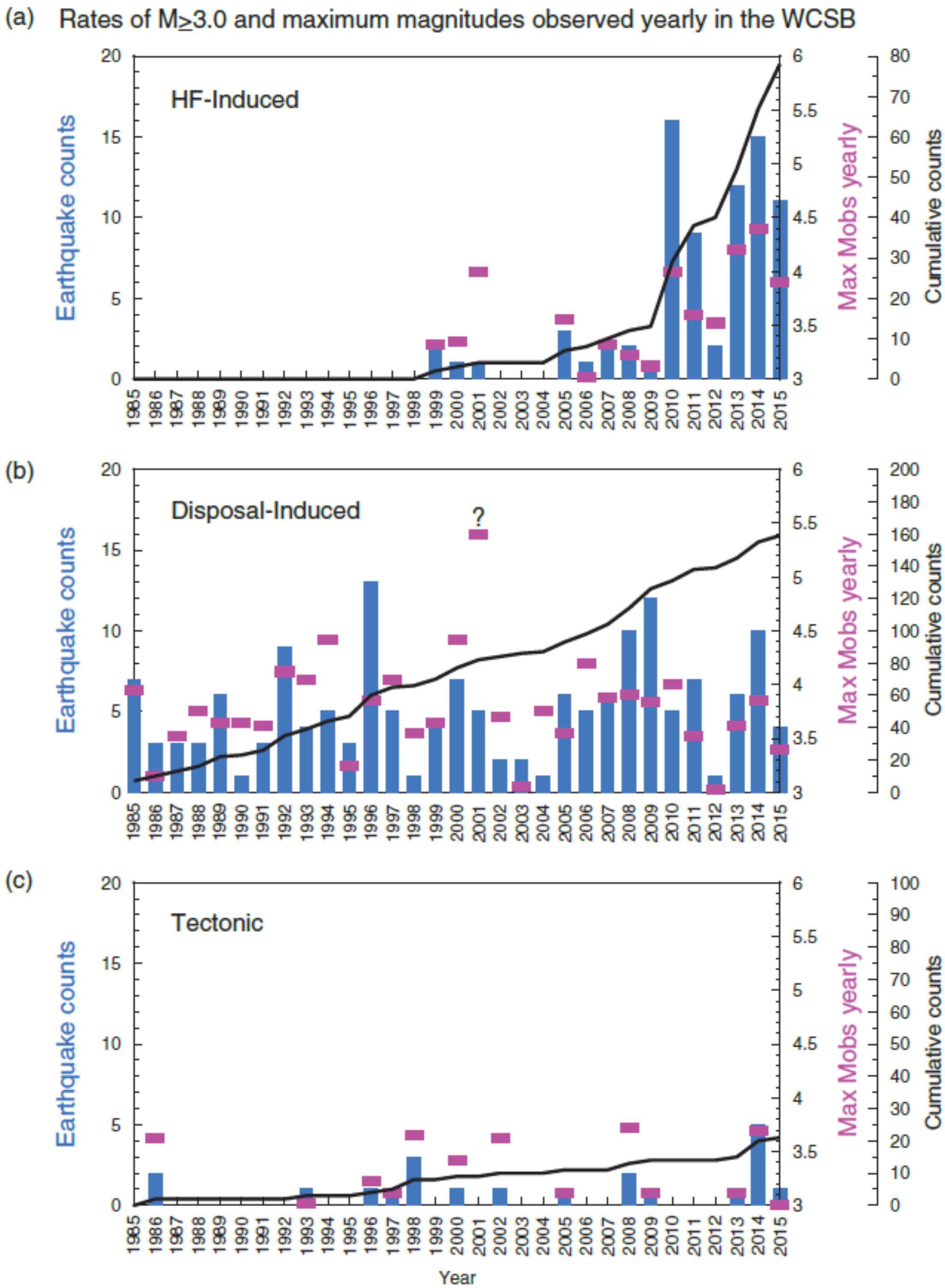

Figure 17. Plots showing the annual rates of M≥3 earthquakes in the Western Canada Sedimentary Basin (WCSB) that are (a) linked to hydraulic fracturing, (b) linked to fluid disposal, and (c) tectonic. Source: Atkinson et al. (2016).

5.2. Susceptibility to Anomalous Induced Seismicity

5.2.1. Concerns Raised

Most fluid-injection operations do not induce anomalous seismicity. Within Western Canada, between 1985 and 2015, 1% of disposal wells and 0.3% of hydraulic fracturing operations were linked to AIS with M>3 (Atkinson et al. 2016). Spatially, AIS is observed in clusters and not scattered across a region with active fluid-injection operations. Differentiating why certain areas are more susceptible to AIS, understanding the variability within susceptible areas, and accurately forecasting whether a fluid-injection operation is susceptible to AIS are key challenges expressed by several expert presenters regarding efforts to better predict, manage, and mitigate the potential impacts of AIS.

5.2.2. Summary of Expert Evidence Considered

An assessment of the potential for seismogenic fault slip is required by operators in the KSMMA prior to hydraulic fracturing (BCOGC 2018 Industry Bulletin), and is required during application for new fluid disposal projects (BCOGC Application Guidelines for Deep Well Disposal)[52]. The susceptibility of existing disposal wells was assessed by the BCOGC during the re-issuing of approvals. Conducting a comprehensive risk assessment prior to hydraulic fracturing is also one of the seven Industry Shared Practices suggested by CAPP[53] and the minimum requirements for assessing the potential for AIS are described in the CAPP[54] Hydraulic Fracturing Operating Practices.

Fault Slip Activation Mechanisms

Fluid injection associated with wastewater disposal and hydraulic fracturing increases pore-pressures and/or alters poroelastic stresses. When the increased pore pressures contact a nearby fault, either directly or through a permeable pathway (i.e. pore pressure diffusion), the increased pore pressure reduces the "effective normal stress", which lowers the "critical shear stress" on the fault, bringing the stress regime into a state of failure (Figure 18a; Healy et al. 1968; Raleigh et al. 1976). This effectively changes the loading conditions on a pre-existing fault, which then may dynamically rupture, producing an earthquake. Poroelastic stress perturbations resulting from injection (Figure 18b) may also result in the reactivation of faults located a great distance from the source (Segall and Lu 2015; Bao and Eaton 2016; Chang and Segall 2016; Deng et al. 2016). Seismicity resulting from pore pressure diffusion is believed to occur closer to the injection source, at higher rates (Segall and Lu 2015; Chang and Segall 2016),

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[52] BCOGC Application Guideline for Deep Well Disposal: https://www.bcogc.ca/node/8206/download

[53] CAPP Hydraulic Fracturing Industry Shared Practices: Anomalous Induced Seismicity Due to Hydraulic Fracturing: https://www.capp.ca/publications-and-statistics/publications/296978

[54] #7 CAPP Hydraulic Fracturing Operating Practice, Anomalous Induced Seismicity: Assessment, Monitoring, Mitigation and Response.

and is persistent for longer periods of time following injection (Bao and Eaton 2016) than seismicity resulting solely from poroelastic stressing.

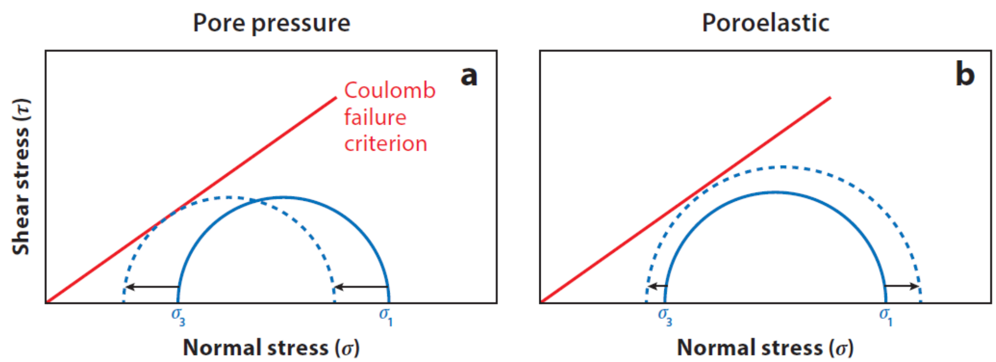

Figure 18. Schematic Mohr circle diagram showing the effects of (a) increased pore pressure and (b) poroelastic stress perturbations in response to fluid-injection. (a) Increasing pore pressure reduces the normal stress on the fault, moving the circle to the left and closer to the failure criterion. (b) Poroelastic stress changes increase the differential stress on the fault, increasing the diameter of the circle, which brings it closer to the failure criterion. Source: Keranen and Weingarten (2018).

The mechanism of seismic fault slip involves unstable rupture, where the sliding resistance along the fault (which weakens with sliding) decreases faster than the elastic unloading during sliding. While many questions still exist regarding the nucleation, propagation, and arrest of dynamic slip resulting from fluid-injection, modelling studies on faults pressurized due to increased pore pressures have provided some insights (Garagash and Germanovich 2012; Azad et al. 2017; Norbeck and Horne 2018). Results of these modelling studies indicate that slip nucleates when the overpressure, which is the ratio of the pore pressure to effective normal stress, exceeds unity over a sufficiently large area of the fault (referred to as a fault patch). The slip initially propagates quasi-statically (i.e. aseismic/stable), but can transition to unstable slip (i.e. seismic/dynamic) as a result of the slip-weakening nature of fault friction. Based on measurements from a fluid-injection field experiment, Guglielmi et al. (2015) also suggest that aseismic/stable slip is always a precursor to dynamic nucleation and unstable slip. In addition, many studies argue that the migrating, swarm-like foreshock sequences observed before many AIS events result from stable slip (e.g. Chen and Shearer 2013; Chen et al. 2017; Kato et al. 2014; Sugan et al. 2014; Walter et al. 2015).

The results from the modelling studies on the nucleation of dynamic slip (Garagash and Germanovich 2012; Azad et al. 2017; Norbeck and Horne 2018) indicate that the slip always transitions to unstable slip for faults with background shear loading greater than their ambient residual strength (i.e. critically-stressed; Figure 19). For faults stressed below their residual strength, slip is predicted to remain stable when the injection results in hydraulic fracturing conditions on the fault. Otherwise, the slip may transition to an unstable state depending on the background shear loading, overpressure, and residual fault strength (Figure 19). In particular, when imperfectly aligned faults are pressurized over a large patch prior to nucleation of dynamic slip, large earthquakes are predicted.

Fluid-injection seismicity can be classified into two categories of faulting behaviour where the transition between the two is primarily related to the state of stress and frictional parameters (Gischig 2015; Galis et al. 2017; Maurer and Segall 2018; Nobeck and Horne 2018). In low-stress environments (i.e. low shear to normal stress), the perturbed stress and pore pressure fields resulting from fluid-injection may control the ruptures, causing self-arresting dynamic slip on faults, which naturally may not have failed (Figure 20). In high stress environments, fluid-injection likely controls the rupture nucleation, but the rupture may be self-sustaining, only limited by the tectonics, and hence can extend beyond the perturbed fields (Figure 20). Pressure-controlled or self-arrested seismicity falls under the often used definition for “induced” seismicity, whereas self-sustaining or runaway seismicity is often defined as “triggered” (e.g. Dahm et al. 2013 2015; Shapiro et al. 2013; Galis et al. 2017; Maurer and Segall 2018; Megalooikonomou et al. 2018).

Natural earthquakes resulting from dynamic stress transfer due to other earthquakes are defined as “triggered” (e.g. Freed 2005). Consequently, many authors refer to all anthropogenic seismicity as “induced”, a convention adopted in this report (Ellsworth 2013; Rubinstein and Mahani 2015; Atkinson et al. 2016; Ghofrani and Atkinson 2016; Grigoli et al. 2017; Eaton 2018). The terms self-arrested and self-sustained are used when differentiating between faulting behaviours. A distinction is also made here between operationally-induced (i.e. expected microseismicity) and anomalous induced seismicity (i.e. larger magnitude and nuisance seismicity) following the convention of Eaton (2018).

Controlling Parameters

The activation mechanisms for fluid-injection induced seismicity implies three conditions are needed: a pre-existing fault capable of dynamic rupture, an injection source sufficient to change the pore pressures and/or stress on the fault such that it ruptures, and a pathway for pressure diffusion and/or stress transfer from the injection source to the fault. Numerous studies have attempted to discriminate which factors primarily control the susceptibility to inducing anomalous seismicity by fluid-injection (e.g. Pearson 1981; Lee and Wolf 1998; van Eijs et al. 2006; Bachmann et al. 2012; Brodsky and Lajoie 2013; Goertz- Allmann and Wiemer 2013; Troiano et al. 2013; Segall and Lu 2015; Skoumal et al. 2015; Weingarten et al. 2015; Langenbruch and Zoback 2016; Eaton et al. 2018; Gischig and Wiemer 2013; Hincks et al. 2018; Kao et al. 2018; Norbeck and Rubinstein 2018; Pawley et al. 2018; Schultz et al. 2018). Fluid-injection volumes, pressures, and rates; cumulative injection volumes; depth to basement; proximity to reefs; pore fluid overpressures; tectonic stress regime and strain rates; and rates of natural seismicity have all been suggested to primarily control the susceptibility to AIS.

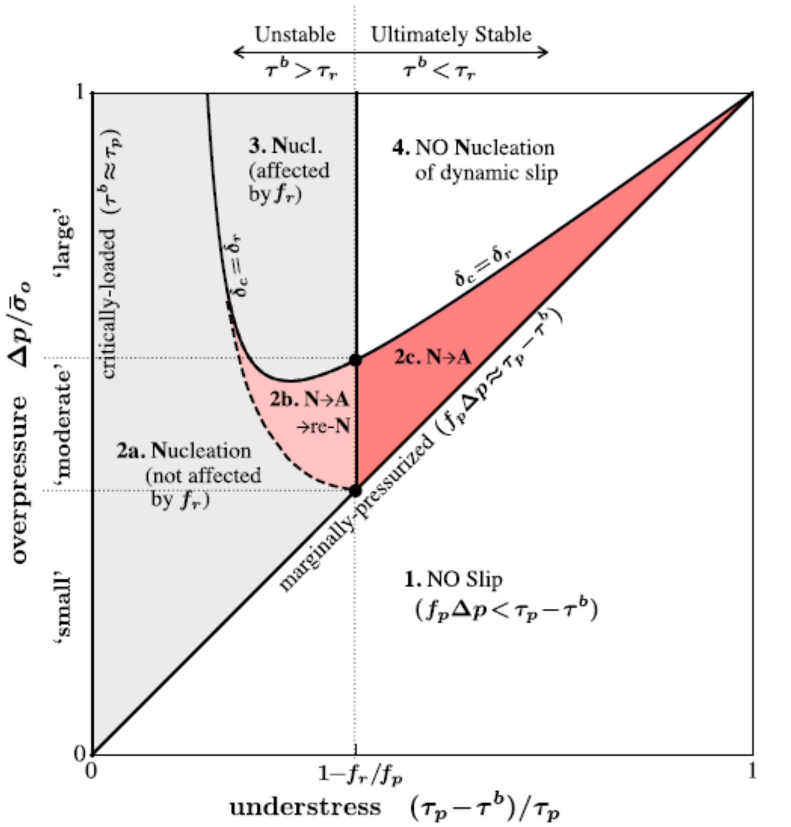

Figure 19. Plot showing the different slip regimes depending on the overpressure (ratio of change in pore pressure, Δp, to the original effective normal stress) and the understress (ratio between ambient peak shear strength, τ_p, minus the background shear stress, τ^b, and the ambient peak shear strength). Source: Garagash and Germanovich (2012).

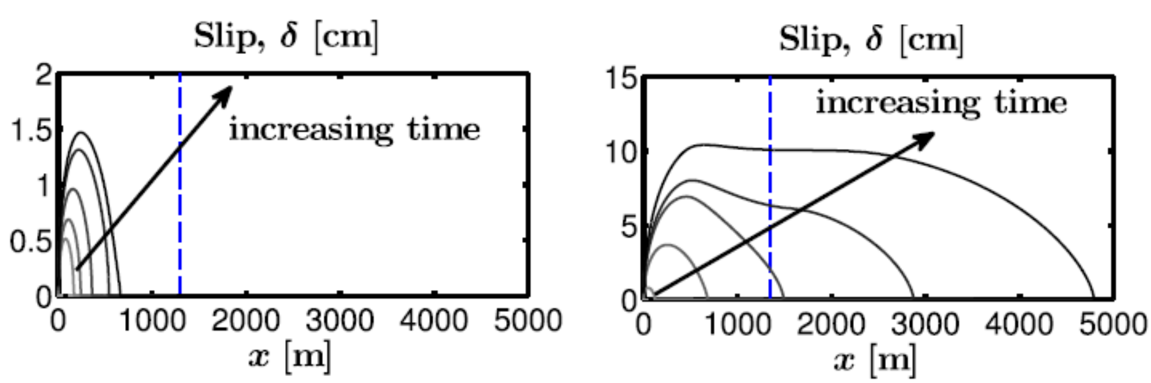

Figure 20. The predicted slip (y-axis in cm) versus size of fault rupture (x-axis in m) calculated by Norbeck and Horne (2018) for (left) self-arrested slip, which is confined by the pressure front (blue dashed line) and (right) self-sustained slip, which extends beyond the pressure front and is limited by fault size.

Several experts demonstrated that the susceptibility to AIS in NEBC can be correlated to cumulative injection volumes (Farahbod et al. 2015; Kao et al. 2018). Cumulative injection volumes have also been correlated with the susceptibility to AIS globally (Shapiro et al. 2011; van der Elst et al. 2016). In particular for NEBC, areas with dense hydraulic fracturing operations (Babaie Mahani et al. 2017) or hydraulic-fracturing operations near disposal wells (Ghofrani and Atkinson 2016) have been shown to have higher susceptibility to AIS. The correlation between injection volume and induced seismicity may not be physical, but statistical, as a larger volume of the subsurface experiences elevated pore pressures or changes in stresses for larger volumes of injected fluids, which increases the likelihood of intersecting faults (Figure 21) and of the fault slipping unstably (e.g. Atkinson et al. 2016). The impact of temporal variations in injection volumes for different hydraulic fracturing completion styles on the susceptibility to AIS, however, remains a key knowledge gap expressed by several experts. Several experts explained that although a correlation exists between cumulative injection volumes and event numbers as well as between event numbers and maximum magnitudes in NEBC (Farahbod et al. 2015; Babaie Mahani et al. 2017; Kao et al. 2018), many areas with high injection volumes do not induce anomalous seismicity. Geological factors likely account for the remaining spatial variability in susceptibility as found for the Duvernay Play in Alberta (Schultz et al. 2018).

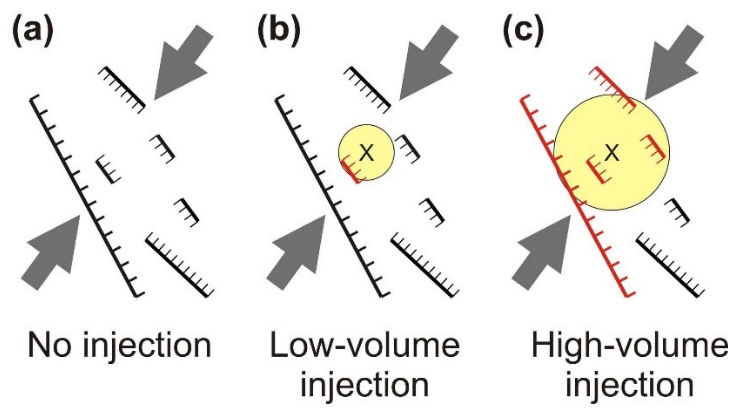

Figure 21. Schematic diagram showing the increased likelihood of intersecting faults for higher volume injections. Source: Kao et al. (2018).

The tectonic strain rate was demonstrated by one expert, based on his recent research (Kao et al. 2018a), to be the primary geologic control on the spatial distribution of AIS on a regional scale for Western Canada. If the susceptibility of AIS in NEBC is primarily controlled by the tectonic strain rate, as concluded by Kao et al. (2018), then the available tectonic moment may be depleted, thus reducing the potential for inducing events in the long-term.

Reservoirs with highly overpressured pore fluids (Eaton and Schultz 2018) have also been suggested to increase the susceptibility to AIS in NEBC. Overpressurizing reservoirs through fluid disposal is also argued by the BCOGC to increase the susceptibility to AIS, particularly to latent, post-injection AIS. The depth to basement from the injection source has been demonstrated to be the primary geologic control on disposal-injection induced seismicity in the U.S. (e.g. Horton 2012; Kim 2013; Keranen et al. 2014; Hornbach et al. 2015; Chang and Segall 2016; Yeck et al. 2016; Candela et al. 2018; Hincks et al. 2018) as well as on hydraulic fracturing induced seismicity in the Duvernay Play in Alberta (Pawley et al. 2018). The depth to basement is less important in NEBC due to the shallower depth of the Montney Play (>1 km to the basement compared to <500 m to the basement for the Duvernay Play; Kao et al. 2018a). However, ~90% of observed anomalous seismicity in NEBC induced by hydraulic fracturing is from operations in the Lower Montney as reported by BCOGC. The much higher likelihood of inducing anomalous seismicity due to hydraulic fracturing in the Lower Montney than the Upper Montney (BCOGC 2014[55]; Babaie Mahani 2017; Kao et al. 2018) suggests a depth dependence, which is likely related to greater natural faulting in the Lower than the Upper Montney, as suggested by one industry expert. A closer proximity to faulting in addition to poor reservoir quality were shown to correlate with anomalous seismicity induced by fluid disposal. The known geological factors controlling AIS can be used to train a logistic regression machine learning algorithm to map the susceptibility to inducing anomalous seismicity as demonstrated by Pawley et al. (2018) for the Duvernay Play in Alberta.

Forecasting Susceptibility

Regional susceptibility studies were said to be starting to provide insights into the spatial distribution of AIS in NEBC; however, forecasting whether a specific operation will induce anomalous seismicity requires physics-based modelling with accurate hydro-geomechanical parameters. It was stated, that the industry's ability to identify faults from 3-D seismic, as argued by many expert presenters, is one of the key opportunities but also challenges to forecasting and mitigating AIS. In particular, imaging moderate-sized faults and faults with little vertical offset are challenging and remain areas of active research. In addition to reactivation occurring on faults not visible from seismic data, the experts also noted that known faults often do not induce anomalous seismicity (e.g. BCOGC 2012[56]). Forecasting whether a fault will be susceptible to unstable slip in response to fluid-injection activities requires accurate and routine measurement of the ambient and injection-induced stresses as well as the heterogeneous fault frictional and hydraulic parameters. Specifically, measuring the magnitude of the maximum horizontal stress is pointed out by many experts as a key challenge. Improving our understanding of fault behaviour, particularly the role of aseismic slip, which requires more

[55] BCOGC (2014) Investigation of observed seismicity in the Montney Trend, URL: https://www.bcogc.ca/node/12291/download
[56] Investigation of Observed Seismicity in the Horn River Basin: https://www.bcogc.ca/node/8046/download

accurate measurement of fault friction and cohesion parameters and their heterogeneity, is also listed as a key challenge by some experts.

Presentations from academic researchers with expertise in AIS explained that the data measurement and modelling techniques necessary for physics-based modelling are still in development. In particular, designing a computational framework combining earthquake fault mechanics and reservoir simulation modelling approaches is a key area of active research mentioned by several experts. Statistics-based probabilistic frameworks, however, have proven useful for forecasting fault susceptibility. A preliminary map of the susceptibility of AIS in the WCSB based on a statistical model was provided by Ghofrani and Atkinson (2016; Figure 22). Another example was presented by one academic expert based on his research (Walsh and Zoback 2017), where the probability of pore pressure diffusion inducing fault slip in Oklahoma was calculated from stress and fault parameters using quantitative risk assessment (QRA). QRA refers to tools for evaluating the likelihood of an outcome and can be used to predict the susceptibility to AIS, the likelihood the ground shaking resulting from the seismicity will be a hazard, as well as the risk of exposure to the hazard given its vulnerability. A free tool for quantitatively predicting fault slip potential is available from the Stanford Center for Induced and Triggered Seismicity[57].

Current research is focused on data-driven modelling, a hybrid method coupling physics- and statistical-based approaches (e.g. data trained machine learning). Several experts listed acquiring sufficient data for hybrid approaches as a main challenge to preventing AIS in response to fluid injection. The operators often have collected some/all of the necessary data; however, these data are rarely shared with the regulators and researchers, limiting the advancement of effective forecasting methods.

5.2.3. Key Findings

Geological factors, primarily tectonic strain rates and fluid overpressures, likely control the susceptibility to AIS in response to fluid injection in NEBC on a regional scale, whereas cumulative injection volumes likely control whether a specific operation will induce events within geologically susceptible regions. While recent studies have improved our understanding of the regional susceptibility of AIS, many experts expressed concern that increased data sharing and research capacity are still needed to define a location model for the susceptibility to AIS in NEBC.

An assessment of susceptibility to AIS was conducted on existing disposal wells by the BCOGC and is required during application for disposal well licences. An assessment of susceptibility to AIS is also required by Special Order in the KSMMA (BCOGC 2018) prior to hydraulic fracturing operations, but not elsewhere in NEBC. Conducting accurate, quantitative assessments of the

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[57] Stanford Center for Induced and Triggered Seismicity: https://scits.stanford.edu/

seismic susceptibility of specific fluid-injection operations, however, is limited by current data measurement and modelling technology. The experts expressed concerns regarding identifying faults in 3-D, measuring the ambient and induced stress field, measuring and modelling the dynamic fault friction and cohesion, understanding the impact of completion styles, and developing computational frameworks.

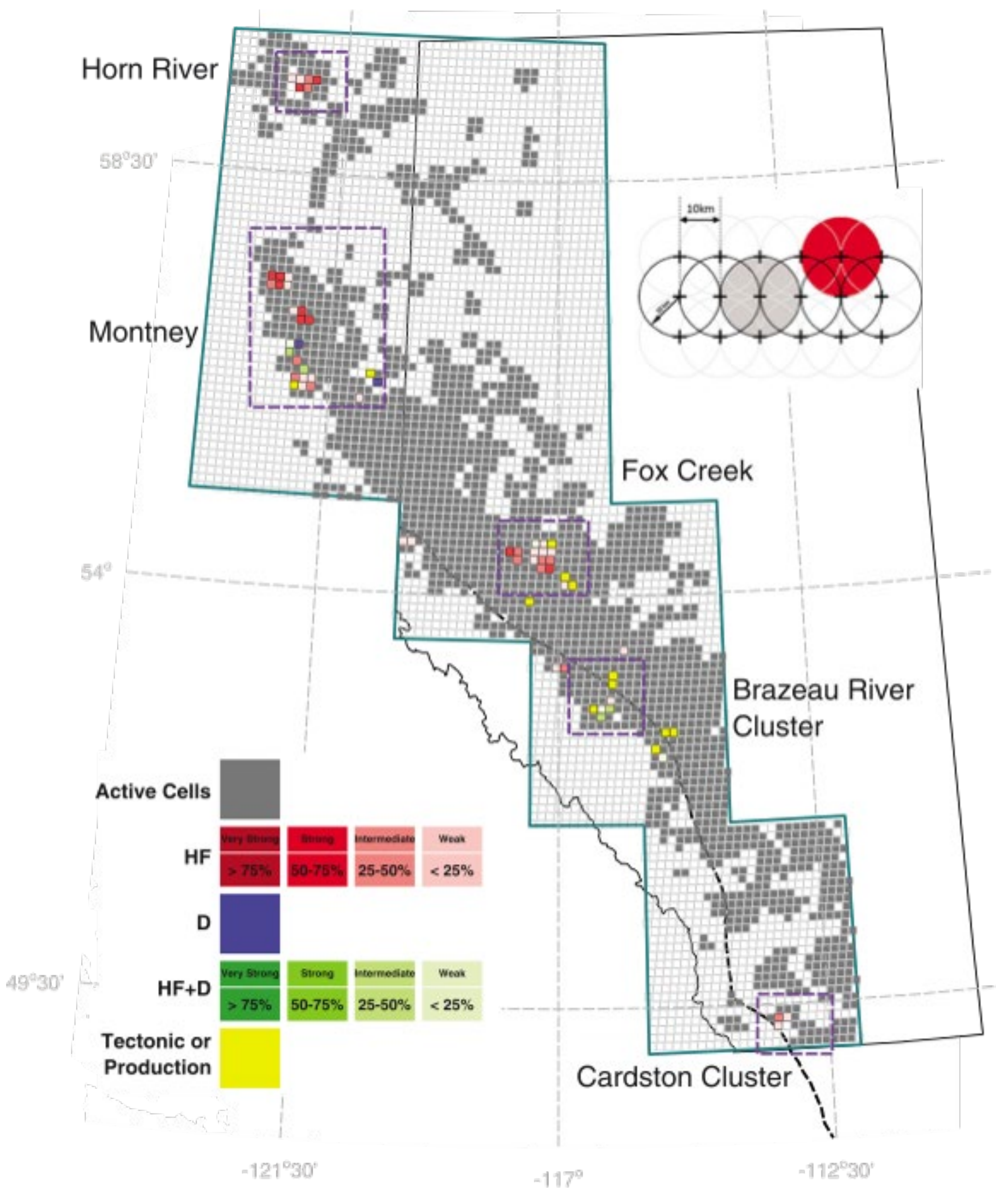

Figure 22. Susceptibility map for tectonic earthquakes (yellow), anomalous seismicity induced by hydraulic fracturing (red), anomalous seismicity induced by fluid disposal (blue), and anomalous seismicity induced by a combination of hydraulic fracturing and fluid disposal (green). Source: Ghofrani and Atkinson (2016).

5.2.4. Recommendations

It is recommended that operators be encouraged to conduct a quantitative assessment of fault slip potential prior to all fluid-injection operations. A standard, quantitative approach should be included as a minimum requirement for assessing the potential for AIS in industry recommended operating practices.

A susceptibility map should be derived for NEBC similar to Pawley et al. (2018) for the Duvernay Play in Alberta. The mapping will require a regional fault model, thus the BCOGC should put measures in place to facilitate collaboration and data sharing between operators and between industry and researchers.

Increasing the confidential access for researchers to interpretations of industry conducted field and lab tests, including 3-D seismic, microseismic, and seismic monitoring, would also promote research into understanding fault behavior and developing hybrid and physics-based frameworks for forecasting the potential for seismogenic fault slip in response to fluid-injection operations.

Increased sharing of seismic monitoring data and/or denser network coverage (discussed in Section 5.5) is needed for further investigation into the apparent increased susceptibility of hydraulic fracturing operations near disposal wells and in areas with dense hydraulic fracturing.

It is also recommended that the BC Seismic Research Consortium, Oil and Gas Development Induced Seismicity Working Group, Canadian Induced Seismicity Collaboration, and/or Microseismic Industry Consortium be expanded or a new consortium be formed to focus and increase research capacity.

5.3. Seismic Hazard Assessment

5.3.1. Concerns Raised

Whether a fluid-injection operation poses a hazard of an anomalous induced event, depends on the susceptibility to inducing seismicity, as discussed in Section 5.2, as well as whether the ground shaking from an event has the potential to cause harm. The intensity of ground shaking is a function of magnitude, proximity to the earthquake, site amplification effects, and source radiation pattern. Earthquake intensity, commonly defined by the Modified Mercalli Intensity Scale (MMI), provides a measure of whether an event will be felt or cause damage, whereas earthquake magnitudes provide a quantitative measure of the amount of seismic energy released by the event. According to MMI, earthquakes with intensities less than VI, which generally corresponds to M<4, are not expected to cause structural damage. Earthquakes with MMI V (~M3.5 to 4) may cause non-structural damage, while events with MMI > II (~M>1.5) may be felt (Figure 23).

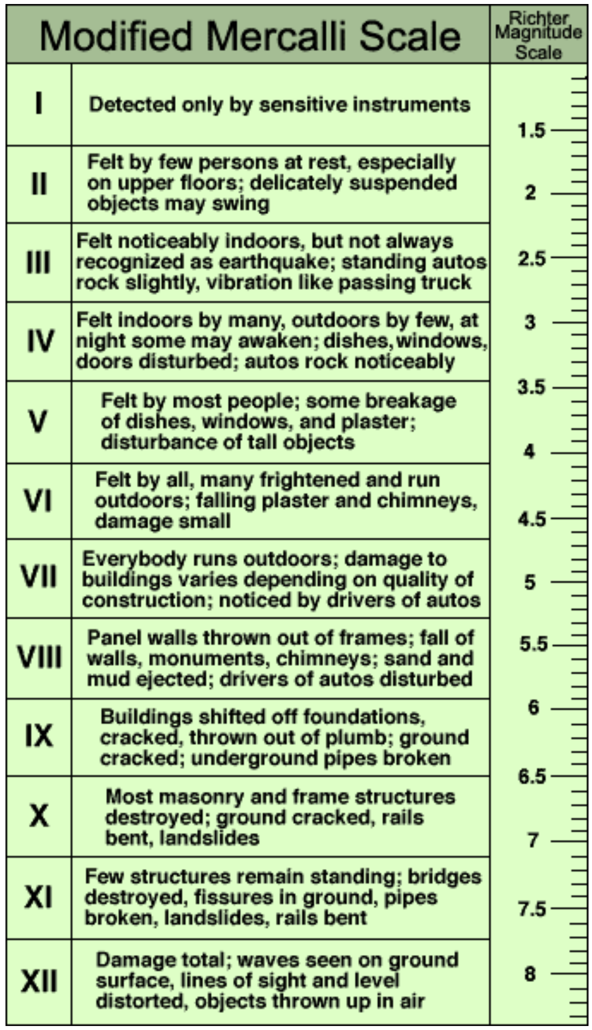

Figure 23. Modified Mercalli intensity scale (MMI) compared to Richter (i.e. Local) magnitude scale (M_L) for measuring the size of earthquakes. Source: Missouri Geological Survey[58].

The hazard from earthquakes can be assessed through physics- or statistics-based approaches or a hybrid-approach combining the two. In a physics-based approach, stress fields and faults are characterized and coupled-flow models are used to assess the seismic hazard. Collecting the necessary data and developing computational framework are challenges expressed by the experts (see concerns discussed in Section 5.2), which limits the current use of physics-based approaches. More commonly, statistics-based probabilistic approaches are used, where rate and location models, maximum magnitude predictions, and ground motion prediction equations are used to assess the probability of exceeding ground motion thresholds (e.g. Atkinson et al. 2015; Weingarten et al. 2015). The experts interviewed by the Panel expressed

[58] The Relationship between Richter Magnitude and Modified Mercalli Intensity https://dnr.mo.gov/geology/geosrv/geores/richt_mercali_relation.htm

concern regarding the uncertainty in all the key parameters necessary for an accurate probabilistic seismic hazard assessment. Whether ground motion thresholds are the best measure of hazard or the best method for communicating the hazard to the public were also concerns expressed by the AIS experts who presented to the Panel.

5.3.2. Summary of Expert Evidence Considered

In KSMMA, operators are required to submit a pre-assessment of seismic hazard with a notice of operation prior to hydraulic fracturing activity. CAPP Hydraulic Fracturing Operating Practice also requires members to assess the potential for inducing anomalous seismicity and to the risk of exposure to the associated hazard.

Magnitude-Frequency Distribution and Maximum Magnitude

The rate of recurrence of earthquakes is assumed to follow the power-law Gutenberg-Richter relation (GR) which predicts larger magnitude earthquakes for greater event numbers (i.e. amount of earthquakes). The GR has been shown to adequately represent the magnitude-frequency distribution of anomalous seismicity induced by fluid-injection (van der Elst 2016), including seismicity induced in NEBC as shown by a couple academics (Farahbod et al. 2015; Kao et al. 2018). For natural seismicity, the slope of the magnitude-frequency distribution, defined as the b-value, is typically ~1.0, which implies for every 100 M2 earthquakes there will be one M4 earthquake. The calculated b-values from induced seismicity have been reported to range from 0.6 to 2.1 (van der Elst et al. 2016). The BCOGC presented that in the N. Montney, a b-value of 1.0 is observed, whereas in Septimus in the S. Montney a larger b-value of 1.8 is observed (Figure 24). For a b-value of 1.8, around 4,000 M2 events are induced for every M4. Therefore, given the same number of smaller earthquakes, fewer big earthquakes are expected in the S. Montney than the N. Montney.

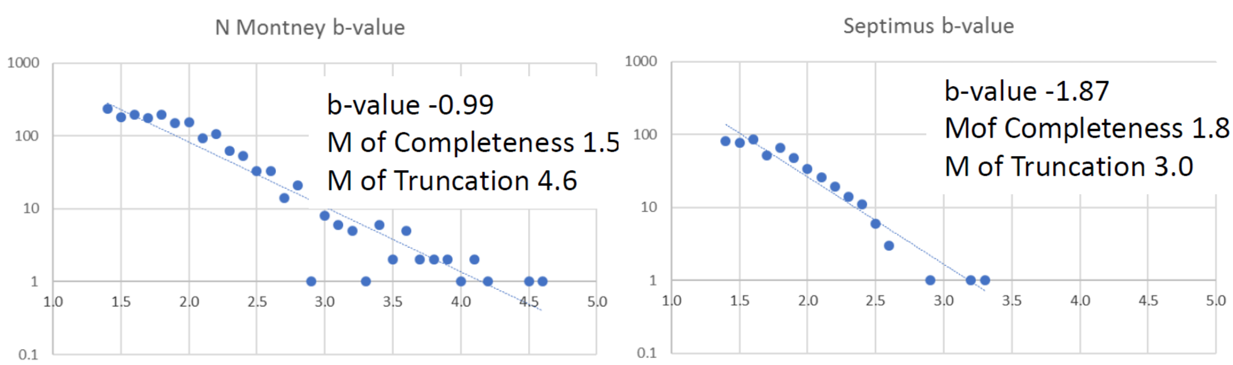

Figure 24. Gutenberg-Richter (GR) plots for the N. Montney (left) and the Septimus area in the S. Montney. The y-axis is number of events and the x-axis is magnitude. The calculated slope, b-value, magnitude of completeness and magnitude of truncation are shown for each area. Source: BCOGC.

Some researchers argue that a seismogenic-index modified GR, which considers the non-stationary (i.e. time-dependent) effects of the injected volume, better represents the magnitude-frequency distribution than GR for induced seismicity (Shapiro et al. 2011, 2013; Hallo et al. 2014; Galis et al. 2017; Schultz et al. 2018; Verdon and Budge 2018). The seismogenic index is a measure of the site-specific seismotectonic characteristics (Dinske and Shaprio 2013). It has been further suggested that the two categories of faulting behavior may be better represented by different magnitude-frequency distributions. Whereas, GR is likely a good representation for self-sustaining seismicity, a seismogenic-index modified GR may be more appropriate for self-arrested seismicity (McGarr and Simpson 1997; Shapiro et al. 2013; Galis et al. 2017). Additionally, it has been argued that there is a fundamental difference between small and large magnitude earthquakes (e.g. Viesca and Garagash 2015) and that GR might not be appropriate for operationally-induced seismicity where b-values are typically >1.5 (e.g. Hallo et al. 2014 and references therein). For example, Eaton et al. (2014) suggest that a log-normal fracture distribution may provide a better fit to the observed magnitude-frequency distribution and that the observed change in b-value, commonly attributed to fault reactivation (Maxwell et al. 2009) may result from the strongly laminated nature of the reservoirs.

The magnitude-frequency distribution provides an estimate of the maximum magnitude from the frequency of earthquakes. van der Elst et al. (2016) demonstrated that the maximum magnitude of induced seismicity is as expected from the number of observed events. Based on his research, one academic showed that for Western Canada, a correlation exists between maximum magnitude and the number of earthquakes for areas with more than 35 events (Figure 25; Kao et al. 2018). Farahbod et al. (2015) demonstrated a correlation between maximum magnitude and earthquake frequency in the Horn River Basin and Schultz et al. (2018) demonstrated a correlation exists in the Duvernay Play in Alberta.

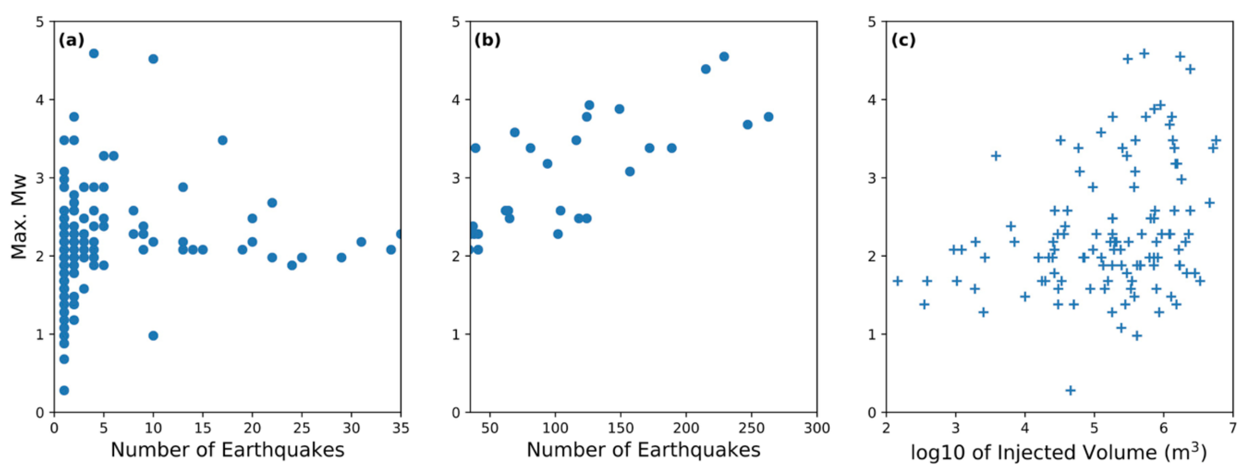

Figure 25. Relationship for Western Canada between maximum magnitude per area and (a) number of earthquakes for areas with less than 35 events, (b) number of earthquakes for areas with less than 35 events, and (c) injection volume. Source: Kao et al. (2018).

The frequency of earthquakes induced by fluid-injection operations have also been shown to correlate with the maximum cumulative injection volume (e.g. Shapiro et al. 2011; van der Elst et al. 2016). A correlation, therefore, must also exist between maximum magnitude and cumulative injection volume. The academic demonstrated from his research that for Western Canada, there is a correlation between maximum magnitude and injection volume (Figure 25; Kao et al. 2018).

Some researchers have suggested that the cumulative injection volume (Hallo et al. 2014; McGarr 2014; McGarr and Barbour 2018) or the extent of the resulting diffusion front (Shapiro et al. 2011) provide upper limits on the maximum magnitude of event that can be induced. Other researchers, however, argue that a deterministic upper bound is only applicable for self-arrested seismicity, whereas the maximum magnitude for self-sustaining events is bound only by tectonics (e.g. Galis et al. 2017; Maurer and Segall 2018). Based on his research, one academic showed that while the majority of induced events in NEBC are consistent with an upper bound calculated either from the cumulative injection volumes or sample size, some events induced by hydraulic fracturing operations have larger magnitude than predicted from the cumulative injected volume (Figure 26; Atkinson et al. 2016; Eaton and Igonin 2018).

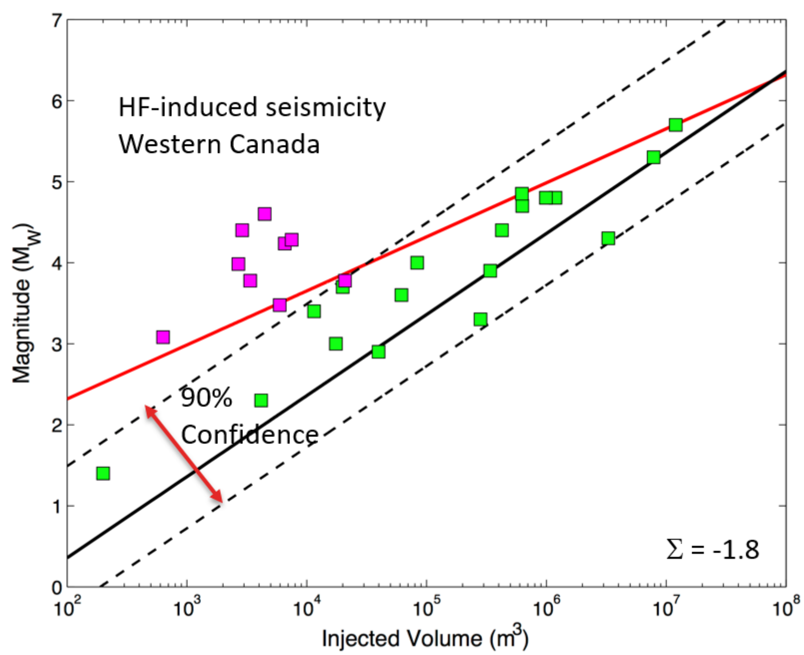

Figure 26. Maximum magnitude of seismicity induced by hydraulic fracturing (HF-induced) in Western Canada versus injected volume compared to proposed limits on maximum magnitude. Red solid line is the volume-based upper limit (McGarr 2014) and black dashed lines represent the confidence region from the sample size limit (van der Elst et al. 2016). Green squares represent events within the confidence region from the sample size limit and the purple squares are events outside the confidence region. ∑ is the seismogenic index. Source: Eaton and Igonin (2018).

At the time of the expert presentations to the Panel, four earthquakes with M≥4 had been induced by fluid-injection activities in NEBC. One of the M≥4 events was induced by fluid disposal in the N. Montney, two were induced by hydraulic fracturing in the N. Montney, and one event in the S. Montney was within an area with both active disposal and hydraulic fracturing. On November 30th, 2018, hydraulic fracturing in the S. Montney induced M4.0 and M4.5 earthquakes. The largest induced earthquake, to date, in NEBC was a M4.6 on August 17th, 2015 in the N. Montney. During several presentations to the Panel, it was noted that larger magnitude earthquakes are expected in the N. than S. Montney as a result of the larger mapped faults and lower calculated b-value. This observation may need to be re-evaluated following the very recent M4.5 earthquake that was induced in the S. Montney.

The experts agree that the maximum magnitude of an event that could be induced in NEBC is unknown, but is likely the same as for natural seismicity. Predicting maximum magnitudes for natural seismicity is still a challenge. Current convention estimates maximum magnitude from a combination of paleoseismological data, historic seismicity, fault geometry, and empirical scaling relations (e.g. Thingbaijam et al. 2017). Since 1985, when monitoring stations were first deployed in NEBC, two natural earthquakes were recorded with M≥3, the largest was a M3.3 on May 2nd, 1992.

Ground Motion Prediction Equations

Seismic hazard decreases for large hypocentral distances (distance from source of the event) due to the attenuation of ground motions. The relationships between peak ground motions and hypocentral distance are defined by ground motion predictions equations (GMPE). The ground motion parameters most commonly used for GMPE are the peak ground acceleration (PGA) and peak ground velocity (PGV). In general, PGA of an earthquake tends to correlate with felt effects, while the damage potential is more closely correlated with PGV. Several experts presented that recent analyses of ground motions recorded in NEBC from anomalous events induced by fluid-injections operations have developed GMPE for induced seismicity (Figure 27; Atkinson 2015; Babaie Mahani and Kao 2017). The results indicate that ground motions from induced events can be of larger amplitude than natural events due to their typically shallower depths. The experts also noted that the lack of near-field data for M≥4 events is a challenge to predicting ground motion from both natural and induced earthquakes. The two November 30th, 2018 events are the first M≥4 events to be induced since the BCOGC introduced the permit requirements for ground motion monitoring.

Several experts presented that in addition to attenuation, site amplification and source radiation effects may also strongly impact the observed ground motions, resulting in significant scatter in ground motions for a given hypocentral distance and magnitude, and thus uncertainty in GMPE (Figure 27). It was noted by a couple experts that in an ongoing study, Monahan et al. (2018) are characterizing the near surface over the Montney Play, in order to map the amplification of ground motion. ShakeMaps can then be created, by combining site amplification maps with GMPE, in order to provide near-real-time maps of the ground motions resulting from AIS. One academic noted that understanding the radiation pattern of the ground motions for AIS in NEBC, which will differ depending on the source mechanism, remains an open area for research. While the experts agree that the ground motion monitoring requirement of the BCOGC is ahead of other regulators, several experts expressed concern whether the single station requirement is adequate to fully understand the ground motions resulting from induced events in NEBC.

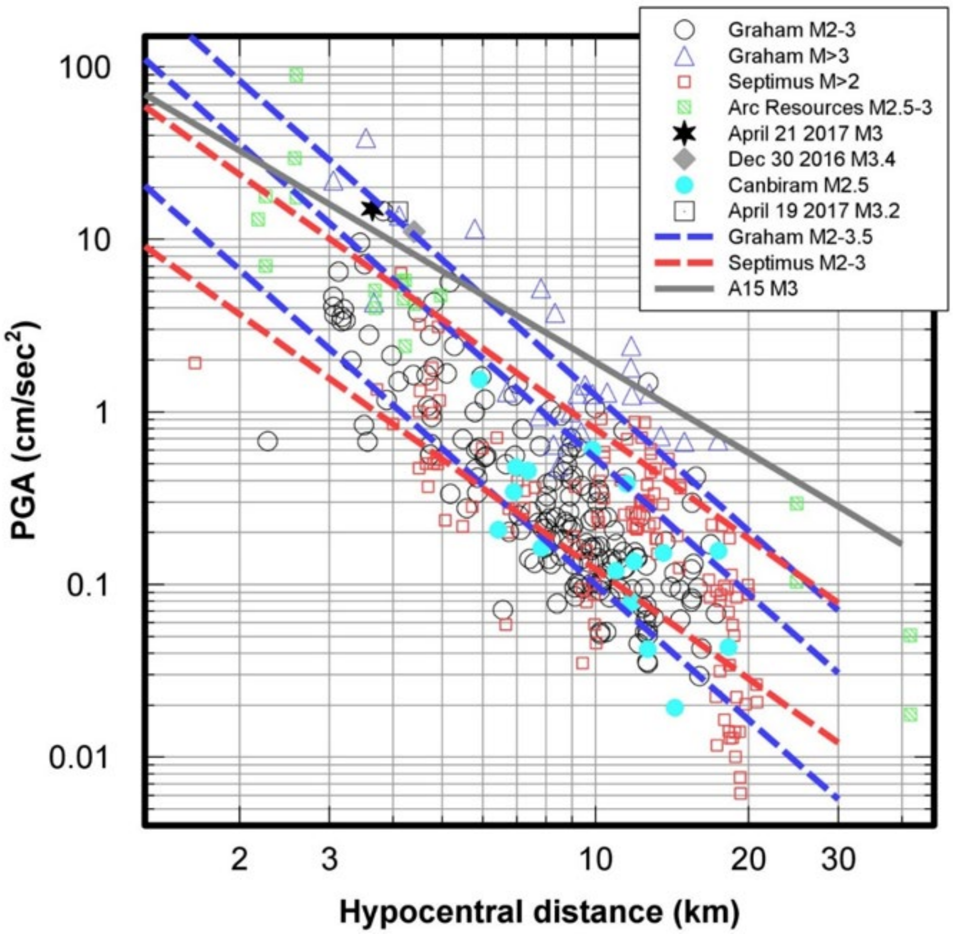

Figure 27. The peak ground acceleration (PGA) versus hypocentral distance for earthquakes recorded in the Montney. The predicted relationship (dashed and solid lines) for different magnitudes from ground motion prediction equations are also plotted. The relationships predicted by Babaie Mahani and Kao (2017) for the area around the Graham disposal well for M2, 3, and 3.5 are plotted as blue dashed lines and their predicted relationship for M2 and 3 in the Septimus area are plotted as red dashed lines. The solid grey line shows the relationship predicted by the equation calculated by Atkinson et al. (2015) for M3 earthquakes. Source: BCOGC.

5.3.3. Key Findings

Prior to hydraulic fracturing, operators in KSMMA are required to submit a seismic hazard assessment. An assessment is not required elsewhere in the province; however, it was noted by several experts that the risk is lower outside KSMMA due to the lower population and amount of critical infrastructures. CAPP members are required to conduct a comprehensive seismic hazard assessment through Industry Shared Practices[59].

The experts who addressed the Panel highlighted that collecting the necessary data and developing computation framework are key challenges limiting quantitative assessment through physics-based or hybrid approaches (as discussed in Section 5.2). Statistics-based probabilistic approaches require location and rate models, a prediction of maximum magnitude, and ground motion prediction equations. Significant advances were reported in developing ground motion prediction equations and mapping the amplification of ground motions; however, understanding the magnitude-frequency distribution, maximum magnitude, and ground motion radiation remain areas of needed research.

5.3.4. Recommendations

Similar to susceptibility (Section 5.2) operators should be encouraged to conduct a quantitative seismic hazard assessment prior to all fluid-injection operations. It is recommended that a standard, quantitative approach be included as a minimum requirement for assessing the seismic risk in industry recommended operating practices.

Better data sharing, increasing research capacity, and expanding monitoring (discussed further in Section 5.5) are needed to better understand magnitude-frequency distributions and how they may be used to forecast maximum magnitude, and to reduce the variability in GMPE.

5.4. Mitigation

5.4.1. Concerns Raised

As discussed in the previous two sections, the large number of variables and the industry's limited ability to measure and model them makes forecasting AIS in response to fluid-injection operations difficult. Therefore, mitigation plans are typically employed in an attempt to limit the seismic hazard for operations which induce anomalous events. Usually, mitigation plans for induced seismicity employ a traffic light protocol (TLP), which is a real-time, risk-management tool with multiple thresholds invoking specific actions (Bommer et al. 2006). Generally, small events are initially induced in response to fluid injection, while the frequency and sometimes

[59] CAPP Hydraulic Fracturing Industry Shared Practices on AIS: https://www.capp.ca/publications-and-statistics/publications/296978

magnitude of events increase with the cumulative injected volume. The ultimate goal of a TLP is to prevent inducing larger earthquakes by changing operations when events of specified thresholds are induced. Operations proceed as planned for events with a green light. If an event is detected equal or greater to the yellow light threshold, then monitoring and/or reporting are increased or mitigation measures are initiated. Operations are typically suspended when a red light event is induced. The thresholds used for different jurisdictions are included in Table 1.

The industry and academic experts presenting to the Panel expressed concerns regarding the effectiveness of a TLP for mitigating induced seismicity in NEBC and listed developing a proactive instead of a reactive approach as a key challenge. Specific concerns include the use of magnitude rather than ground motions for thresholds; the inability to mitigate post-injection seismicity; the lack of measurable precursor events before many large induced events; whether the red light thresholds are adequate to prevent public concern; and that other potential hazard indicators cannot be integrated into the protocol. In addition, most experts presented that understanding which mitigation measure will be most effective and whether flow-back will prevent or promote inducing anomalous seismicity are key challenges. It was noted, however, that mitigation is a greater concern for hydraulic fracture operations, whereas more control and oversight exists for disposal wells. Through mitigation measures, anomalous seismicity induced by disposal has been minimized to M<2.5 since March 2018.

Jurisdiction	**Yellow**	**Red**
United Kingdom	0.0	0.5
Ohio	0.5	1.0
KSMMA in NEBC	2.0	3.0[a]
Oklahoma	1.8[b]	3.5
Alberta	2.0	4.0
British Columbia	-	4.0
Colorado	2.5[c]	4.5

[a] or clusters of events
[b] site-specific threshold
[c] or any felt event

Table 1. The thresholds used in traffic light protocols for different jurisdictions. Modified from Eaton (2018).

5.4.2. Summary of Expert Evidence Considered

Induced seismicity experts for BCOGC presented that regulations for BC include a stoplight protocol, which requires the suspension of fluid-injection operations when a seismic event of M4.0 or greater is induced. Operations may resume after a mitigation plan has been approved by the BCOGC. In KSMMA, where the majority of seismic complaints originate, a TLP is required during hydraulic-fracturing, with a yellow light at M≥2 requiring activation of a mitigation plan and a red light at M≥3 requiring suspension of operations. Inducing clusters of events from the same operation may also require the suspension of operations. Four hydraulic fracturing operations have been suspended to date in NEBC, three in the N. Montney and one in the S. Montney. Anomalous seismicity induced by disposal wells is closely monitored by BCOGC and wells which are, or may be, problematic are shut-in. Seven disposal wells have been shut-in as a result of AIS, five in the N. Montney and two in the S. Montney.

Operators within KSMMA must submit a copy of their mitigation plan to BCOGC prior to hydraulic fracturing activities. Developing a response plan, as well as documenting the roles and responsibilities of personnel, is included in the CAPP Operating Practices[39].

Concerns with Traffic Light Protocols

The most frequently expressed concern to the Panel, regarding the current mitigation regulations, is that the impact of an event is not adequately represented by the magnitude threshold. However, while most experts agreed that ground motion information should be incorporated into TLPs, it was also argued that, due to the high variability in ground motions and limited accelerographs, ground motion information should only be used to drive the magnitude thresholds for TLPs.

Several experts presented that while a TLP may be effective in KSMMA in the S. Montney, where large induced earthquakes are typically preceded by clusters of smaller events, in the N. Montney, precursor events have not been observed for many large earthquakes. One industry expert noted that only 60% of AIS with M≥3 in the N. Montney have observed precursor events. The N. Montney is also observed to induce more latent anomalous seismicity, which occur post-injection when currently used mitigation measures cannot be employed. The lack of yellow light events preceding the very recent (November 30th, 2018) M4.5 earthquake induced within KSMMA, may also require a reassessment of the effectiveness of a TLP. Many experts presented that identifying other potential hazard indicators, most specifically aseismic slip, and integrating them within a proactive mitigation plan are key challenges.

No concerns were expressed by the experts regarding the current mitigation of anomalous seismicity induced by disposal wells. It was noted that the slower increase in injected volumes compared to hydraulic fracturing results in lower magnitude precursor events and allows sufficient time to employ mitigation measures. By reducing injection rate and wellhead injection pressure and shutting-in problematic wells, disposal induced seismicity has been continuously declining with no M≥2.5 events occurring since March, 2018. In particular, it was noted that limiting the reservoir pressure of the disposal formations has decreased latent AIS.

Alternatives to Traffic Light Protocols

The development of proactive mitigation protocols for anomalous induced seismicity requires either physics-based models capable of forecasting the rate and magnitude of events from numerical models or statistics-based approaches. Physics-based models require characterization of nearby faults and the local stress field, which remain challenging. Statistical approaches forecast the event population based on the observed magnitude-frequency and spatial-temporal distributions, which requires sensitive monitoring. Several operators presented that they include monitoring the frequency and magnitude of events and/or the clustering of events along lineaments in their mitigation plan. In a recent study of AIS in the Horn River Basin, Verdon and Budge (2018), demonstrated how the statistics can be used to forecast the maximum magnitude of an event which may be induced.

Operational Changes for Mitigation

Understanding which mitigation strategies will be most effective is a key challenge acknowledged by all experts in their presentations to the Panel. Anecdotal evidence was provided that AIS can be most effectively mitigated by allowing increased pore pressures to dissipate by increasing the relaxation time and time for fluid imbibition. Making adjustments to the completions program by staggering or skipping stages or wells are the techniques currently used by operators to allow pressures to dissipate. In addition, one operator presented that they limit hydraulic fracturing operations to the daytime, which both allows the pressures to dissipate overnight and decreases the likelihood of small events being felt. Recent research has also demonstrated that changing the capillary pressures through hydraulic fracturing fluid chemistry can increase the rate of fluid imbibition and thus the dissipation of pore pressures (Bustin et al. 2018).

Anecdotal evidence was also provided that reducing pump pressure/rate has been effective at mitigating AIS. As explained by one academic, reducing the injection volume has a similar effect to increasing the distance between the injection and the fault, which partitions a greater percentage of the energy into creating a hydraulic fracture network than into inducing seismogenic slip on the fault. Dispersing the injection by increasing perforations, which was also reported as a potentially successful mitigation measure, may similarly reduce the energy partitioned to the fault.

Changing fluid properties, by reducing tonnes of proppant or increasing viscosity were also suggested as possible mitigation measures. It was noted by the experts that the impact of proppant on AIS is poorly known and requires further research. Proppant may act as a mitigation measure if a proppant bank is formed at the fault decreasing the pore pressure diffusion; however, as the fracture closes, the proppant may induce poroelastic stress changes that may promote seismicity. Based on his modelling of the Horn River Basin (Reynolds et al.

2017), one expert explained that increasing the viscosity of the hydraulic fracturing fluid can reduce the energy partitioned to the fault, similarly to reducing injection pressure/rate.

The only mitigation technique available to operators post-injection is extracting brine by flowing back the well. While in some cases flow-back may have successfully lowered pore pressure diffusion to faults, anomalous events have also been observed during the flow-back period. A couple academics explained that while flow-back likely reduces pore pressures on the fault when they are hydrologically connected, the impact may not be quick enough to mitigate AIS. Additionally, AIS may occur during flow-back if the fault is not in equilibrium with the hydraulic fracture network and remains pressurized or if poroelastic stress changes induced by flow-back destabilize the fault. Understanding whether flow-back is a mitigation tool or will further induce anomalous seismicity is a key challenge expressed by many experts.

The Montney Operators Group and CAPP are currently collecting operators' experiences with mitigating AIS in Western Canada to try and develop a best practice guideline. However, as explained by several experts, evaluating the success of a mitigation technique is difficult, given the industry's current inability to forecast what would have happened without mitigation. Several experts commented that a more quantitative approach is needed to evaluate which strategies will be most effective. The experts suggested that earth models should be developed based on field and laboratory data to test different mitigation strategies, as described by Maxwell et al. (2018). In addition to ranking the effectiveness of mitigation measures, other goals of the modelling include understanding which operational scenarios and completion styles partition the greatest percent of the energy to the hydraulic fracturing and which promote aseismic fault slip rather than seismic rupture.

5.4.3. Key Findings

Regulations in BC require a suspension of fluid-injection operations when a seismic event M≥4 is induced. The suspension of hydraulic-fracturing operations in the KSMMA, where the majority of seismic complaints originate, is required when a M≥3 event or a cluster of events is induced. Operators in KSMMA are also required to submit a mitigation plan, which must be implemented when a M≥2 is induced.

The experts frequently expressed concern to the Panel that the seismic hazard from AIS is not adequately represented by the magnitude threshold. The experts agreed that ground motion information should be incorporated into TLPs; however, while some experts argued that ground motions should be used for thresholds, others argued that ground motions should only be used to drive the magnitude thresholds for TLPs.

Additionally, it was noted that a TLP is ineffective for mitigating M≥4 earthquakes without significant precursor events or that occur post-injection. Such events are common in the N. Montney where a stoplight is enforced and the risk of exposure to seismic hazard is low. In KSMMA, within the S. Montney, a true TLP is enforced during hydraulic-fracturing and most large induced earthquakes occur during injection following clusters of smaller events. The effectiveness of the TLP in KSMMA, however, may need to be re-evaluated following the November 30th, 2018 M4.5 event, which was not preceded by a yellow light event (M≥2).

It was suggested by several experts that increased research and data sharing is needed to develop a proactive mitigation plan to replace the reactive TLP. In a proactive approach, forecasts of the rate and magnitude of AIS are made based on predictions from physics-based models, observed spatiotemporal and/or magnitude-frequency statistics, and/or other potential indicators, such as aseismic slip.

Evaluating the effectiveness of mitigation strategies for AIS in response to hydraulic fracturing is a key challenge noted by all experts. While operators experiences are currently being collected to develop guidelines for best practices, several experts suggested a more quantitative approach should be used to rank the mitigation strategies. The experts recommended testing different strategies using earth models calibrated to field observations. The potentially successful mitigation strategies listed by the experts include allowing increased pore pressures to dissipate by making adjustments to the completions program, such as staggering or skipping stages or wells, and reducing the hydraulic fracturing energy partitioned to the fault by reducing injection pressure/rate, increasing the viscosity of the hydraulic fracturing fluid, and dispersing the injection by increasing perforations.

Changing the proppant concentration and flowing back the well were also listed as mitigation strategies. However, the experts noted that more research is needed to understand when such strategies will be effective at mitigating AIS or whether they might promote further events.

The current strategies for mitigating AIS in response to fluid disposal appear to be adequate and the concern from experts was focused on hydraulic fracturing. By limiting reservoir pressures, reducing injection rate and pressure when small induced events are observed, and shutting-in problematic wells, the frequency and magnitude of anomalous seismicity induced by fluid disposal in NEBC has been continuously declining.

5.4.4. Recommendations

Operators should be encouraged to prepare a mitigation plan prior to all fluid-injection operations with a non-negligible seismic hazard as determined by a quantitative seismic hazard assessment.

It is recommended that a 2nd workshop on TLP be organized to debate the effectiveness of the current province-wide stoplight and TLP in KSMMA, what measure should be used for thresholds (magnitude or ground motions), or if a risk-based approach should be adopted (discussed in Section 7.3).

In addition to compiling operators' experiences with mitigation strategies to develop best practices, it is recommended that the strategies should be more quantitatively ranked through a comprehensive modelling study using multiple earth models calibrated to field observations.

Better data sharing, increasing research capacity, and expanding monitoring (discussed further in Section 5.5) are needed to develop a proactive mitigation plan, which requires a better understanding of spatiotemporal and magnitude-frequency distribution of AIS, the development of physics-based models capable of accurate forecasting, and/or the identification and monitoring of other potential indicators, such as aseismic slip. Better understanding the effectiveness of mitigation strategies, in particular flow-back, also requires more data and research.

5.5. Monitoring

5.5.1. Concerns Raised

The monitoring of moderate to large earthquakes (M>1.5) generally employs broadband seismographs. The higher corner-frequency for small magnitude events (M<1.5) enables accurate estimates of source parameters from geophones at a fraction of the cost of broadband seismometers (Yenier et al. 2018; Eaton 2018). Geophones are typically deployed for monitoring operationally-induced seismicity using downhole or surface arrays. Between 6 and 12 geophones are deployed in a single deep, vertical borehole during downhole monitoring of a hydraulic fracturing completion, whereas for surface monitoring hundreds to thousands of geophones are deployed on the Earth's surface. Alternatively, a buried array of geophones can be deployed in shallow boreholes, which reduces the surface noise and hence the number of required receivers by an order of magnitude. The ground accelerations recorded for proximal, large earthquakes are often clipped for both geophones and broadband seismometers; therefore, accelerographs are also required for monitoring large events at close hypocentral distances.

The ground motions recorded by seismographs and geophones are used to calculate the location of the hypocentral source of the earthquake and its magnitude. Of the different magnitude scales, the most commonly used in BC are the Richter, or local, magnitude (M_L) and the moment magnitude. Richter (1935) developed the first logarithmic magnitude scale, which is based on the amplitude of the waveform recorded on a Wood-Anderson torsion seismograph for earthquakes in California. To calculate M_L, the recorded waveform amplitudes must first be corrected to the response from a Wood-Anderson instrument. A correction is also often applied to correct for the local attenuation effects, which may differ significantly from California. Additionally, the Richter magnitude is only valid for certain ranges of frequency and hypocentral distance. The moment magnitude, which was derived in the 1970s, provides the only measure of earthquake size based on the observed release of seismic energy, defined by the seismic moment, M_0 (Kanamori 1977; Hanks and Kanamori 1979). The seismic moment, which is proportional to the fault slip and fault rupture area (Figure 28), is calculated through moment tensor inversions. Moment tensor inversions also provide a more robust estimate of the earthquake depth and a solution for the source focal mechanism, which provides details on the fault orientation and the direction of slip (see Ristau 2004 for a summary). Although M_w provides the best estimate of earthquake size, a large amount of good quality data is needed for moment tensor analysis; therefore, M_L is still used by NRCan for most M<4 events in NEBC.

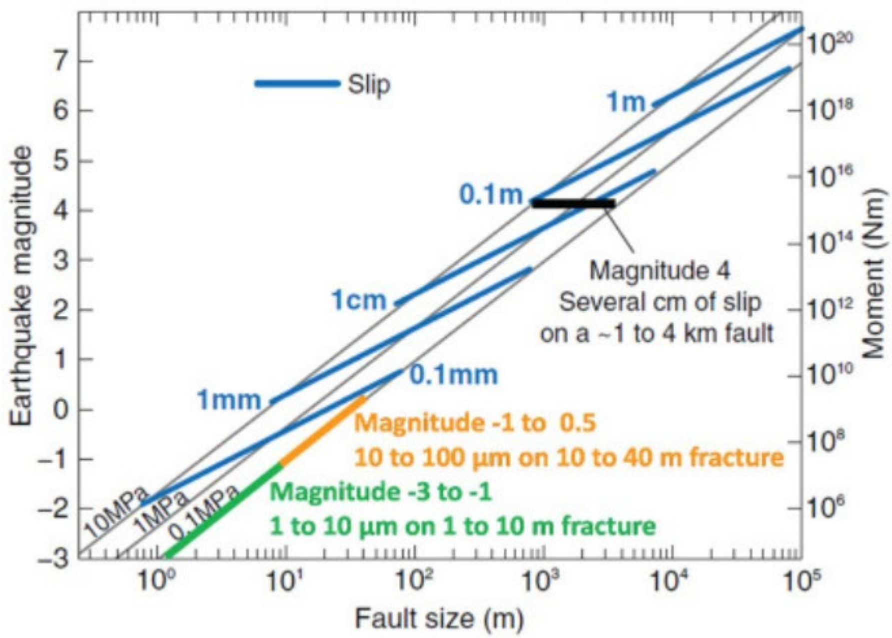

Figure 28. Plot showing the relationship between the size of the fault that slipped and the earthquake seismic moment and magnitude for different stress drops (black lines; in MPa) and fault slips (blue lines; in mm). Source: Maxwell (2013), modified from Zoback and Groelick (2012).

In concerns expressed by the experts, it was noted that a standard approach does not exist for magnitude calculation for AIS in BC, and that magnitude estimates from NRCan are not consistent with those from industry operated, local, dense arrays due to the different approaches and hypocentral distances. As magnitude thresholds are currently used by BCOGC for mitigating AIS, confusion may arise due to differing magnitude calculations. Developing a standard approach for data collection and quality assessment was also recommended by the experts. There was also concern that the equation currently used by NRCan to calculate M_L does not account for local attenuation effects resulting in overestimates. It was recommended by several experts that M_w be used as the standard scale, but that more data are first needed for routine moment tensor analysis.

The experts also noted that the data from the current network does not provide low enough resolution or detectable magnitude to discriminate between natural and induced earthquakes, provide data for calibrating earth models for research projects, or understand the spatiotemporal and magnitude-frequency distributions of AIS, the combined effects and apparent association between AIS and hydraulic fracturing near disposal wells, the time lag between the start of injection and inducing anomalous seismicity, as well as frac hits. While such data are provided by the local, dense arrays, induced seismicity experts for BCOGC and academic researchers indicated that these data are rarely available to the regulator or researchers. It was further noted by one expert that broader network coverage is needed to provide benchmark data in undeveloped areas. As an alternative to increasing monitoring using broadband seismographs, it was suggested that a dense array of geophones could be deployed in areas of higher seismic hazard, at a cheaper cost, to provide data from small events.

Accelerographs record the acceleration of ground motions and the data are typically used to calculate ground motions parameters for earthquakes, which provide a measure of the shaking intensity and damage potential. Commonly calculated parameters include the peak ground acceleration (PGA), peak ground velocity (PGV), spectral intensity (SI) and spectral acceleration (PSA). The duration and frequency content of the ground motions are also typically analyzed to understand the hazard from earthquakes. Concern was expressed by the experts that the current coverage of accelerographs is insufficient to understand which ground motion parameters control whether an event will be felt or how the ground motions relate to damage criteria for structural and non-structural components (discussed in Section 7.3). It was also suggested that more data are needed to understand site amplification effects and radiation pattern, which cause variability in shaking intensity and GMPE. The experts further noted that more ground motions and GMPE with lower variability are needed to generate ShakeMaps, which provide a means of communicating shaking intensity to the public as well as a forecasting tool for seismic hazard. Most experts also suggested that standard practices should be developed for the deployment of accelerographs and the processing of ground motion data.

5.5.2. Summary of Expert Evidence Considered

Expert presentations made to the Panel indicate, that since 2013, when only two CNSN stations were monitoring in NEBC, nine broadband seismographs (the NBC stations) have been deployed (Figure 29). In addition to the NBC and CNSN stations, it was presented that NRCan integrates data from other stations into their processing, including the McGill University dense array in the Doe-Dawson area, AER Raven stations, TransAlta stations, Yukon Geological Survey Liard Basin stations, and University of Ottawa stations (Figure 29 and Figure 30). The BCOGC presented that the addition of the first eight NBC stations lowered the minimum detectable magnitude in NEBC from ~M3 to 1.6-2.6 (Babaie Mahani et al. 2016). The addition of the ninth NBC station, which was donated by a production company in 2016, and the 9-station McGill array further improved the minimum detectable magnitude to M0.6-1.6 in the KSMMA. The greatest improvement is around the McGill array, which is centered within the induced seismicity cluster in the Doe-Dawson area. The current resolution in hypocenter locations within NEBC is approximately ±2 km. The operator-deployed arrays (Figure 30) routinely detect events with magnitudes as small as 0.5 with epicenter location uncertainty of ±100 m and hypocenter location uncertainty of ±250 m; however, it was noted by the non-industry AIS experts that the data are not routinely available to the regulator or researchers.

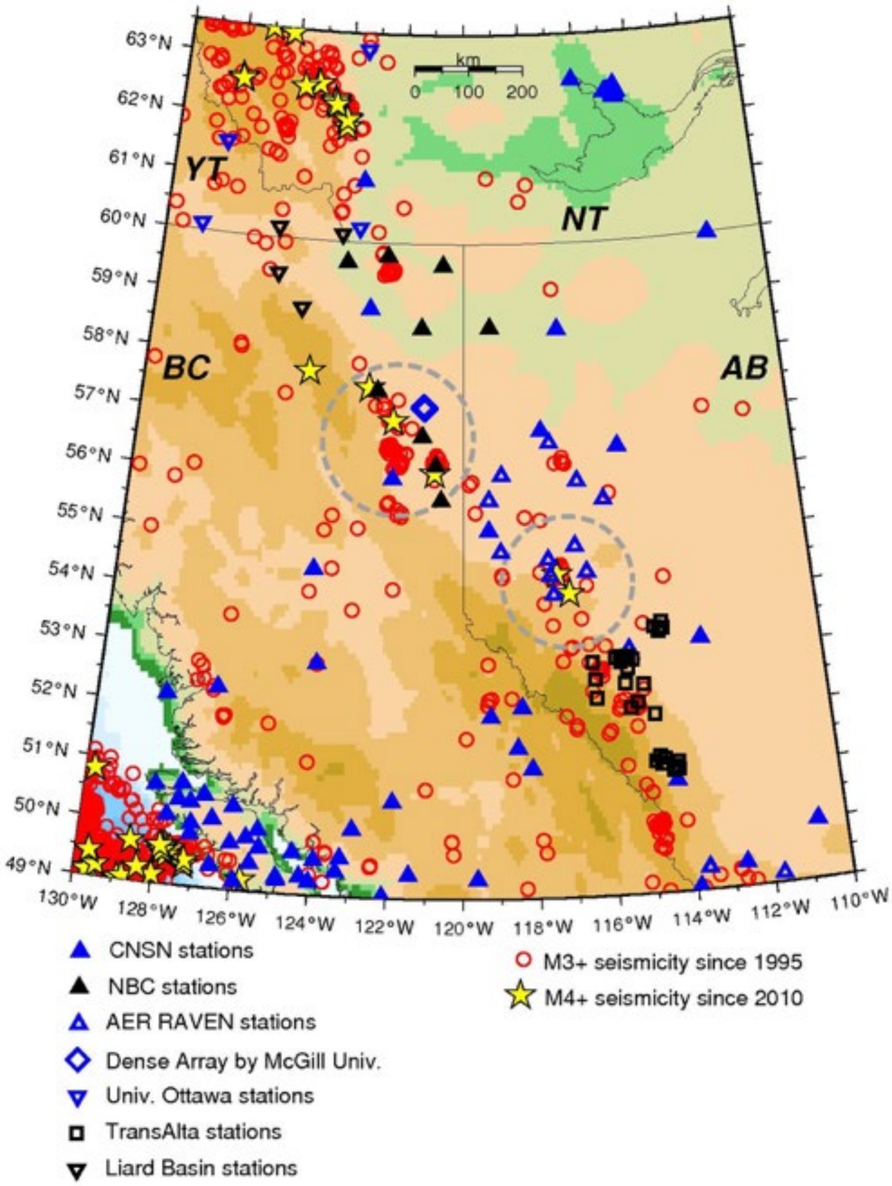

Figure 29. Map of Western Canada showing the location of stations in the regional seismograph networks used by NRCan for calculating earthquake parameters. Earthquakes with magnitudes 3 to 4 (M3+) since 1995 (red circles) and magnitudes 4 and greater since 2010 (yellow stars) are also shown. Source: Kao (presentation to the Panel).

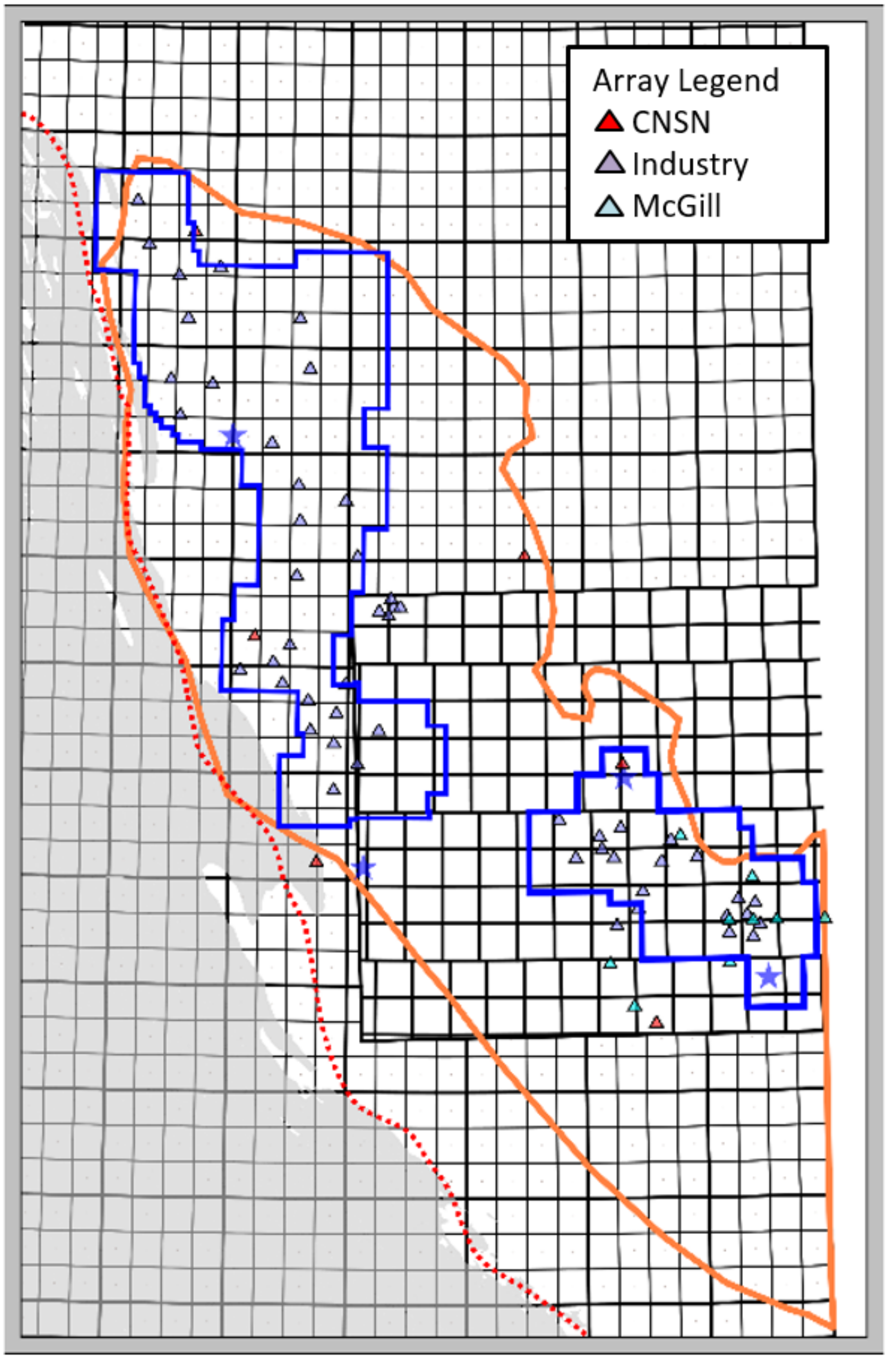

Figure 30. Location of all seismograph stations currently installed in the Montney production trend (orange outline) including the CNSN and NBC stations (red triangles), the stations in the McGill array (light blue triangles), and industry deployed arrays (grey triangles). The two areas requiring the deployment of an accelerograph within 3 km of hydraulic fracturing operations are outlined in blue. The blue stars show the locations of Fort St. John, Hudson's Hope, and Dawson Creek. The red dashed line shows the boundary of the Western Canada Sedimentary Basin. Source: BCOGC.

The BCOGC indicated in their presentation that it is currently installing an additional seven monitoring stations in the Montney, consisting of both a broadband seismograph and an accelerograph (Figure 31). The minimum detectable magnitude following installation of the new seismographs is anticipated to be 0.8-1.4, without the McGill array (Figure 31). The BCOGC is also currently working towards setting up its own server, separate to NRCan's. The new server will allow faster processing and reporting of event information from AIS in BC and greater transparency to the public. By aggregating the data on a separate server, the BCOGC also anticipates improving magnitude calculations.

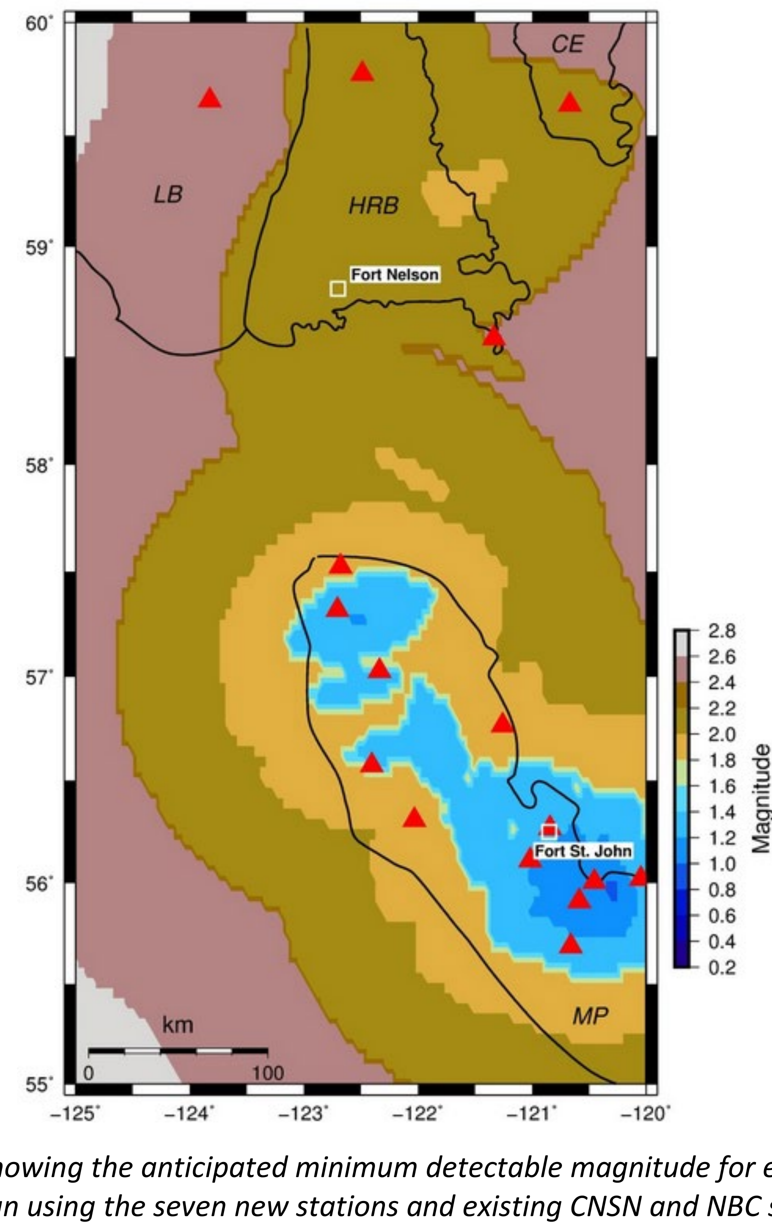

Figure 31. Map showing the anticipated minimum detectable magnitude for earthquakes recorded by NRCan using the seven new stations and existing CNSN and NBC stations (stations shown by red triangles). Source: BCOGC.

The deployment of an accelerograph within 3 km of the well pad is currently required prior to hydraulic fracturing in the two areas in the Montney where anomalous seismicity is induced (referred to in this report as N. Montney and S. Montney; Figure 30). The data recorded for earthquakes with PGA greater than 0.8%, along with the calculated ground motion parameters, are required to be submitted to the BCOGC, which are then released to the public. The installation of the seven new permanent accelerographs and the development of a separate server for processing and reporting the data will improve GMPE and allow the generation of ShakeMaps.

Further Improvements to Monitoring

The experts expressed to the Panel concern whether the current monitoring in NEBC provides low enough detectable magnitudes and hypocenter resolution. It was noted that accurate source parameters for small magnitude events are needed to improve our understanding of the magnitude-frequency distributions and how they relate to maximum magnitudes, which may allow the development of frameworks for statistically forecasting induced seismicity as well as more accurate and detailed probabilistic hazard and risk assessments.

Improving the location uncertainty for recorded earthquakes will improve our understanding of the spatio-temporal variability of induced seismicity and the geological factors contributing to susceptibility, which will aid in the development of location models. Understanding the spatio-temporal distribution of induced seismicity may also aid in the development of proactive mitigation frameworks. In particular, elucidating sequences of events along linear features may be a precursor for larger events. The experts also noted that improved monitoring may help better understand how to mitigate induced anomalous earthquakes with no recorded precursor events and anomalous earthquakes that are induced post-injection.

The current uncertainty in depth estimates was listed by most experts as a key challenge to ensuring reservoir containment and discriminating between induced and natural earthquakes. Since 1985, two natural earthquakes with M>3 have been recorded in NEBC, the largest was a M3.3 on May 2nd, 1992. Various criteria and parameters have been suggested for discriminating induced from natural earthquakes, ranging from simple correlations to hybrid physics/statistics-based approaches (Davis and Frohlich 1993; Dahm et al. 2013). The spatio-temporal pattern, b-value, stress drop, presence of non-double-couple components of source mechanism, characteristics of aftershocks, and swarm-like behavior have all been debated as discriminators for natural versus induced earthquakes (Cesca et al. 2013; Skoumal et al. 2015; Zhang et al. 2016; Huang et al. 2017; Sumy et al. 2017). As induced events typically resemble natural events, several academics presented that the hypocentral depth of earthquakes is arguably the key parameter to distinguish whether events are anthropogenic.

It was also noted during the presentations to the Panel that improved accuracy and catalogue completeness (i.e. minimum magnitude reliably detected) is needed to calibrate physics-based models to test mitigation techniques, develop frameworks for seismic hazard/risk assessment and proactive mitigation, as well as understand fundamental processes, such as nucleation and arrest.

The experts also suggested that improving monitoring coverage will allow further investigations into the apparent association between AIS and the cumulative effects of hydraulic fracturing near disposal wells. The time lag between the start of injection operations and inducing anomalous seismicity might also be more accurately estimated with improved monitoring. While time lags of 4-6 years have been observed for disposal wells in the Montney between start of disposal and induced seismicity, a more complete catalogue might result in shorter time lag estimates, which, in turn, would result in more rapid mitigation and thus reductions in the rate, magnitude, and persistence of induced events. It was further suggested by one expert that a broader coverage for monitoring is needed to provide benchmark data for areas of future development.

In addition to concerns regarding the current coverage of seismographs in the Montney, the experts expressed concern whether sufficient accelerographs were deployed to measure ground motions. In particular, it was noted that more data are needed to improve corrections for site amplification effects and understand the impact of the radiation pattern resulting from the source mechanism, which are necessary to reduce the variability in GMPE. It was also noted by most experts that more data are needed to better understand which ground motion parameters or damage criteria provide the best measure of whether an event will be felt and the potential damage to structural and non-structural components (discussed in Section 7.3). The experts also suggested that increasing the coverage of accelerographs would enable calculation of ShakeMaps, providing a means of communicating shaking intensity to the public as well as a forecasting tool for seismic hazard.

During the presentations to the Panel, most experts were not aware of the current upgrades to the network by the BCOGC. The improved coverage may address many of the concerns expressed to the Panel. A reassessment of the effectiveness of the monitoring network in the Montney is needed following an evaluation of the network performance after the deployment of the new stations. As an alternative to increasing the seismograph network, it was suggested that geophone arrays should be considered to provide a more complete catalogue of induced seismicity.

Standardization

All experts expressed concern to the panel that standard practices do not exist for the deployment of seismographs and accelerographs nor for the processing of the data. The location and type of sensor deployed and processing methodology result in different estimates of magnitude and ground motion parameters from NRCan than from local arrays. As thresholds are set by the regulator for mitigating and reporting AIS, there may be confusion due to inconsistent magnitude and PGA calculations. While NRCan and BCOGC released a document detailing their procedure used to calculate the magnitude of AIS in NEBC (Kao et al. 2017), concern was expressed by some experts that the current methodology overestimates M_L, as demonstrated by Yenier (2017) and Babaie Mahani and Kao (2018). Some experts also suggested that a moment magnitude should be the standard scale used; however, they noted that more data are necessary for routine moment tensor analysis of M<4 induced earthquakes. It was noted to the Panel that operator groups are currently working towards developing standards for deployment; however, it was also noted that a better understanding of the deployment depth, site conditions, and best sensor type is needed to develop effective deployment standards. The Panel heard about several studies investigating the impact of sensor deployment on data measurements.

5.5.3. Key Findings

Since 2013, when only two CNSN stations were monitoring in NEBC, nine broadband seismographs (the NBC stations) have been deployed. In addition to the NBC and CNSN stations, NRCan integrates data from other networks into their processing. The minimum detectable magnitude of events ranges from M0.6-2.6 in NEBC and the location uncertainty is approximately ±2 km. The operator-deployed arrays routinely detect events with magnitudes as small as 0.5 with epicenter location uncertainty of ±100 m and hypocenter location uncertainty of ±250 m; however, these data are not routinely available to the regulator or researchers. To better understand the seismic hazard from AIS, the BCOGC currently requires operators to deploy an accelerograph within 3 km of hydraulic fracturing operations in the N. Montney and S. Montney ground motion monitoring areas. The data recorded for earthquakes with PGA greater than 0.8%, along with the calculated ground motion parameters, are required to be submitted to the BCOGC, which are then released to the public.

Concerns were expressed by the experts that inconsistent magnitude calculations may result in confusion whether thresholds are exceeded; the current NRCan methodology overestimates M_L; and that M_w should be used as the standard scale for routine magnitude calculations. In addition to developing standards for accurate, consistent, magnitude calculations, the experts suggested that standards should be developed for the deployment of monitoring stations.

It was also suggested by the experts that increased seismic monitoring in the NEBC would facilitate the development of frameworks to predict and mitigate seismic hazard as well as to provide background data in areas of future development. In particular, experts noted that increased monitoring is needed to:

- understand the spatio-temporal and magnitude-frequency distributions of AIS;
- discriminate natural from induced seismicity;
- further investigate the apparent association between AIS and hydraulic fracturing near disposal wells;

- calculate the time lag between the start of injection and AIS;
- prevent and mitigate frac hits;
- understand whether anomalous induced earthquakes without significant precursor seismicity can be mitigated; and
- understand fundamental earthquake processes, such as nucleation and arrest.

Concern was also expressed to the Panel by the AIS experts that a single accelerograph is insufficient to:

- decrease the variability in GMPE;
- understand the best ground motion parameter or damage criteria to measure and communicate the shaking intensity from AIS; and
- routinely calculate ShakeMaps.

The BCOGC is currently installing an additional seven monitoring stations in the Montney, consisting of both a broadband seismograph and an accelerograph. The detection threshold following installation of the new seismographs is anticipated to be M0.8-1.4. The BCOGC is also currently working towards setting up their own server, separate to NRCan's, which will allow faster processing and reporting of event information from AIS in BC and greater transparency to the public. By aggregating the data on a separate server, the BCOGC also anticipates improving magnitude calculations, GMPE, and to allow for the generation of ShakeMaps.

Most experts were not aware of the current upgrades to the network by the BCOGC. The improved coverage may address many of the concerns expressed to the Panel; therefore, the effectiveness of the monitoring network in the Montney should be reassessed following an evaluation of the network performance after the deployment of the new stations. As an alternative to increasing the seismograph network, it was suggested that geophone arrays could provide a more complete catalogue of induced seismicity at a fraction of the cost of broadband seismographs.

5.5.4. Recommendations

It was recommended by the AIS experts presenting to the Panel that seismic monitoring be augmented in NEBC. While the BCOGC is currently deploying seven new stations in the Montney, it is uncertain whether the improvements will be sufficient to provide the data necessary to increase research capacity. It is recommended that options should be explored to further augment the monitoring network, possibly with geophone arrays complimented by accelerographs, to provide data for smaller magnitude anomalously induced events and operationally-induced seismicity.

A more complete catalogue of AIS is recorded by operator-deployed arrays and these data should be more readily shared with the regulator and researchers.

Standard practices should be developed for station deployment and monitoring incorporating the results from ongoing research into depth of deployment, site conditions, and sensor type.

Following the BCOGC's investigation into the most accurate methodology for calculating magnitude, a guideline should be developed for standardized magnitude calculation as well as calculation of ground motion parameters.

6. Fugitive Emissions

6.1. Background

Fugitive emissions are a historic and ongoing challenge. Several key public concerns center on fugitive emissions associated with shale gas production including their impact on groundwater resources and air quality as a pollutant, and their contribution to Green House Gas (GHG) emissions. Methane, the major component of natural gas, is a powerful greenhouse gas. As such, the reporting of methane escaping into the atmosphere during shale gas production is important. Studies in the U.S. suggest this can be as high as 3.6 to 7.9% of all shale gas produced, with approximately 50% of these totals being emitted during well completions, venting, and through leaks, with the other 50% being emitted during transport, storage and distribution (Howarth et al. 2011). Numbers reported for BC in the Provincial Greenhouse Gas Emissions Inventory estimate that fugitive oil and gas sources contributed 5.6% of the province's GHG emissions in 2016[60].

With respect to impacts, concerns regarding these fugitive emissions were raised by representatives who spoke on behalf of Treaty 8 First Nations, including the cumulative effects of fugitive emissions on water and air quality. This included a key concern and objection that human health was not part of the Panel's mandate. They noted that there is not enough information or data to identify what the real issues are regarding the impacts of fugitive emissions to know if they are affecting human health or Treaty Rights. An example was provided that Elders have complained for years about what they are seeing in terms of the degradation of the quality of the land associated with natural gas development. What they see on surface is negative, and the subsurface is unknown.

BCOGC (2014) reports a breakdown of total GHG emissions from the oil and gas industry by source as 44% from production and 56% from processing and transport[61]. Activities attributed to production include emissions from drilling, completions and testing, and gas production. A key differentiation is made between venting, where gas is released directly into the atmosphere, and flaring where emissions from burning the gas are released into the atmosphere. BCOGC provides regulatory requirements and guidance through its Flaring and Venting Reduction Guidelines (BCOGC 2018)[62]. These require that all gas flows and emissions sufficient to support stable combustion be flared and that the quantity and duration of vented gas must be minimized and not constitute a safety hazard (e.g. requirements regarding the venting of gas containing hydrogen sulphide or benzene emissions are stipulated; BCOGC

[60] Province of BC Greenhouse Gas Emissions Inventory: https://www2.gov.bc.ca/gov/content/environment/climate-change/data/provincial-inventory

[61] BCOGC 2014 Air Summary Report: https://www.bcogc.ca/node/12928/download

[62] BCOGC 2018 Flaring and Venting Reduction Guideline, Version 5.1: https://www.bcogc.ca/node/5916/download

2018)[63]. All flaring in BC must be conducted in accordance with BCOGC regulations and government air quality objectives and standards. Representatives who spoke on behalf of Treaty 8 First Nations raised concerns that ambiguities in different definitions for what is an emission or release allows industry to under report. Similar concerns were raised by representatives from one ENGO who suggested that fugitive emissions from oil and gas are much higher than are being reported; for example, super-emitters represent a key contributing source, and as they involve unexpected incidents, they are not captured in traditional reporting systems.

Specific to drilling and completions, a significant percentage of the hydraulic fracturing fluid mixed with connate fluids returns to surface before the well is put into production, and with this flowback are large quantities of natural gas. However, in BC, this gas is collected and either conserved (e.g. green completions) or flared in accordance with BC regulations limiting venting[64] (as discussed above). Well permit conditions set by BCOGC place limits on the duration and volume of gas that may be flared[65]. Performance measurements reported by BCOGC (2018)[66] indicate that flaring volumes are less than 0.4% of production volumes.

Aside from these efforts, concerns are also attributed to uncontrolled releases primarily through leaks. After completion, two key sources of concern for leaks are Surface Casing Vent Flow (SCVF) and Gas Migration (GM). These, together with long-term integrity concerns after well abandonment, represent the key knowledge gaps regarding the source of fugitive emissions. SCVF involves the movement of gas through the casing assembly between the surface casing and inner intermediate or production casing (Figure 32). Because the gas is contained, it is easy to detect after the well is completed or monitored during production or prior to final decommissioning of the well. In contrast, GM is more difficult to detect or monitor. GM is defined as the flow of gas outside the surface casing of a well (Figure 32), and thus represents a potential hazard for fugitive emissions entering the groundwater system or atmosphere. GM can be monitored near the well head using a soil vapour survey or through visual indicators such as stressed vegetation or bubbles in standing water. However, concerns also extend to other potential pathways away from the wellbore. This is a key knowledge gap identified by CCA (2014), who suggest that there are a number of potential pathways by which near-surface groundwater resources could become contaminated by shale gas development (Figure 33).

[63] BCOGC 2018 Oil & Gas Operators Manual, Version 1.22: https://www.bcogc.ca/node/13274/download
[64] OGAA Drilling and Production Regulation: http://www.bclaws.ca/civix/document/id/complete/statreg/282_2010
[65] Flaring and Venting Reduction Guideline, Version 5.1: https://www.bcogc.ca/node/5916/download
[66] BCOGC 2017/18 Annual Service Plan Report: https://www.bcogc.ca/node/15106/download

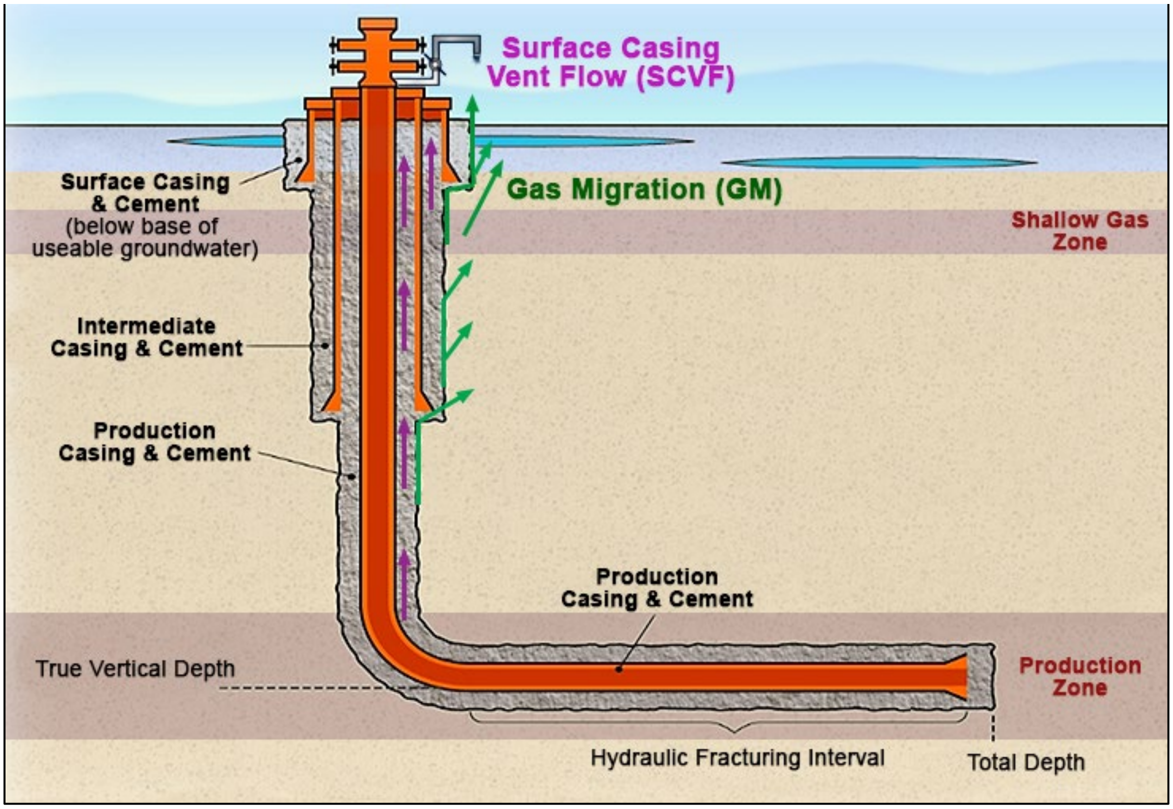

Figure 32. Differentiation of Surface Casing Vent Flow (SCVF) and Gas Migration (GM) relative to concerns of upward gas migration from the producing zone into near-surface aquifers and the atmosphere. Modified after Trican.

Representatives who spoke on behalf of Treaty 8 First Nations also identified concerns that SCVF and GM issues not only encompass the period of production, when monitoring efforts are active, but also extend into legacy effects due to the deterioration of the integrity of these wells over time, especially when they are no longer producing or have been decommissioned. They stated that areas impacted from drilling activities 50 years ago are still being cleaned up, and believe that animals are getting sick from these areas. Protection for animals around old sites is not legislated. Key knowledge gaps in the form of questions include who will keep monitoring these wells, who will fix them in the future, and who will look after them in 100-200 years when they need to be fixed/sealed again?

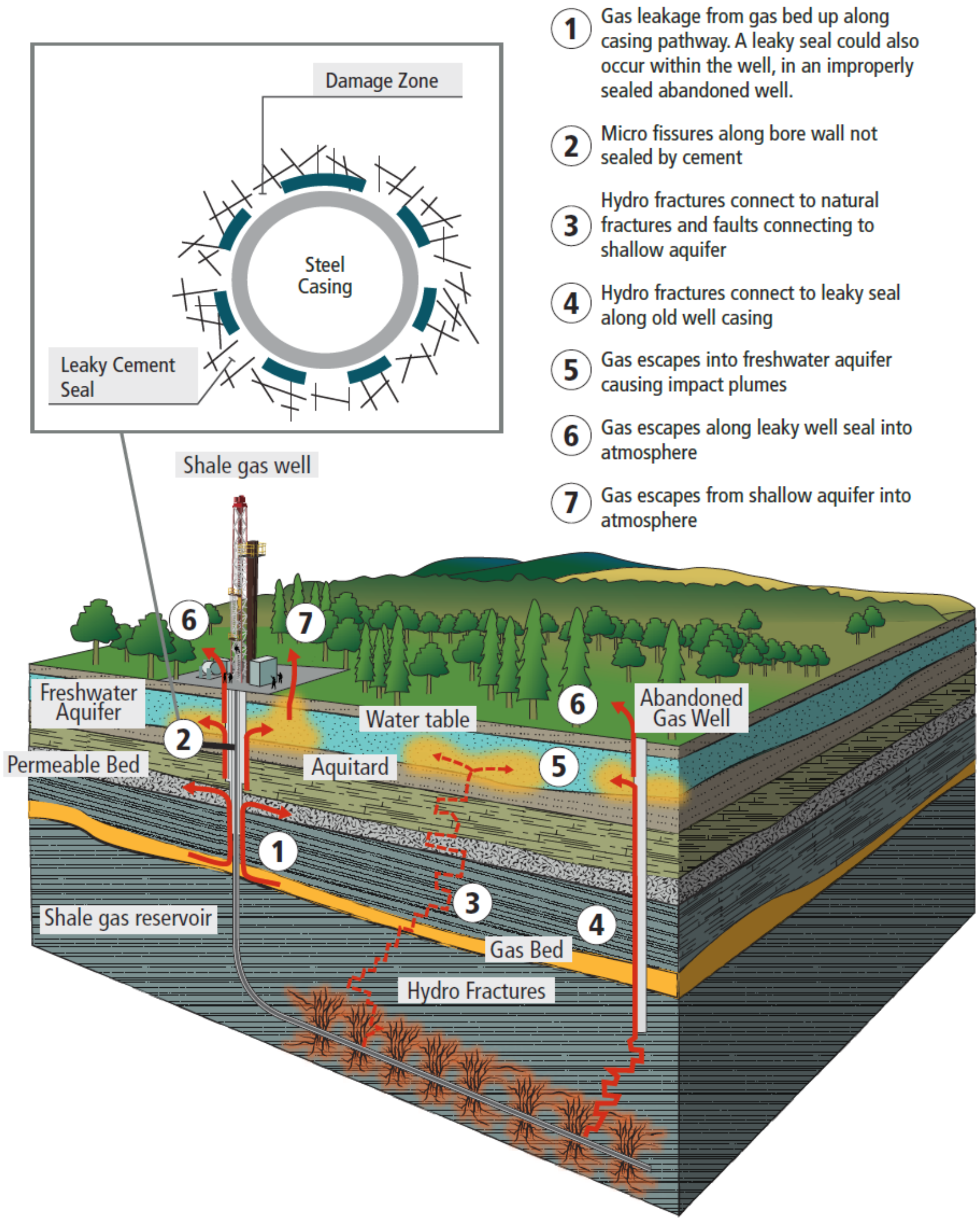

Figure 33. Conceptual pathways by which near-surface groundwater resources could become contaminated by shale gas development, as suggested by CCA (2014). Source: G360 Centre for Applied Groundwater Research, University of Guelph.

6.2. Surface Casing Vent Flow (SCVF)

6.2.1. Concerns Raised

Concerns were raised by representatives who spoke on behalf of Treaty 8 First Nations and ENGOs regarding the potential for leaking gas at depth, which has escaped the containment of the cemented wellbore, making its way upwards towards surface and possibly infiltrating and contaminating groundwater, or reaching the atmosphere, contributing to air pollution and GHG. More specifically, they pointed to the BC Ministry of Health's Human Health Risk Assessment Project[67] and their reporting of identified concerns raised by the public related to natural gas development in NEBC. These included routine gas leaks (SCVF) and flaring possibly leading to exposure to airborne contaminants, respiratory issues (e.g. asthma), and negative health impacts caused by acute and chronic low-level exposure to sour gas and other toxins; sour gas refers to natural gas containing hydrogen sulfide, H_2S, which is toxic at extremely low concentrations.

The Panel notes that Surface Casing Vent Flow (SCVF), by definition, is specific to the upward movement of gas between the surface casing and the intermediate or production casing. Thus, because SCVF only involves the leaking and flow of gas within the surface casing, there are no groundwater risks associated with SCVF. Risk to groundwater only applies if the gas escapes the containment of the casing, in which case it is defined as gas migration (GM). This is addressed separately in Section 6.3. Similarly, SCVF will not pose a risk to the atmosphere unless it is vented. That being said, it was presented to the Panel that the recommended operating procedure is to leave surface casing vents open (Drilling and Completion Committee 2018). To mitigate this, regulations under OGAA and the DPR[68] require that SCVF that presents an immediate safety or environmental hazard must be dealt with immediately, and that venting of gas at volumes sufficient to support combustion is not allowed.

This self-reporting requirement and exceptions to venting of smaller volumes of gas were raised as concerns by ENGOs of under-reporting of SCVF and thus its contribution to GHG. (The Panel notes that new amendments to the DPR, effective January 1, 2020, will require after July 1, 2021 that well permit holders must ensure that fugitive emissions from SCVF do not exceed 100 m^3/day) [69]. In terms of the scale of SCVF, numbers presented to the Panel by BCOGC experts indicate that 9.4% of non-abandoned wells drilled between 2000 and 2014 encountered SCVF incidents, dropping to 7.3% for those drilled post-2015. These are measured, as required by BC regulations, and involve total flows of 8,920 m^3/day, constituting approximately 3% of

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[67] BC Ministry of Health's Human Health Risk Assessment Project: https://www2.gov.bc.ca/gov/content/health/keeping-bc-healthy-safe/oil-and-gas-activities

[68] OGAA Drilling and Production Regulation: http://www.bclaws.ca/civix/document/id/complete/statreg/282_2010

[69] DRP amendments effective January 1, 2020: http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg0286_2018

upstream methane emissions. Approximately 50% of these emissions come from 30 wells. Examining BCOGC's database of SCVF incidents, Wisen et al. (2017) found that the data show 19% of wells drilled after 2010 report leakage. It was also noted that this represented a sharp increase from previously reported incidents and corresponded with regulatory changes requiring leakage testing of a well after drilling and completion. In other words, they report that leakage incident rates are strongly influenced by reporting standards rather than actual well failure rate.

6.2.2. Summary of Expert Evidence Presented

Wellbore Completions

BCOGC presented to the Panel the relevant regulations and standards controlling well integrity and management of SCVF. It was stated that operators must submit reports on their drilling operations including any problems encountered and an evaluation of the cement integrity, and take remedial measures if there is any doubt about the effectiveness of the casing cementation [DPR Sections 18(7) and 32(1)]. BCOGC inspects completions and issues reports on how operators are managing risk and if they meet or exceed standards. Both company and BCOGC reports are published by BCOGC for transparency. During and after completions, operators must check for evidence of SCVF [DPR Section 41(2-4)]. If a vent flow is detected, the permit holder must test the flow rate and buildup pressure and report to the BCOGC, which may then order additional testing, immediate repair, and/or other mitigative measures. It was noted that older wells were not required to be cemented back to surface, resulting in a higher likelihood of leaking due to seals drying out and casing corroding. Regulations require that the surface casing extend below the depth of useable groundwater and be completely cemented in place to surface. New regulations introduced in 2010 further require that all intermediate and production casing be cemented to the surface or a minimum of 200 m above the shoe of the previous casing string.

In presenting the causes of SCVF, an academic specializing in well cementing research related that 10-20% of wells experiencing leaks is a good guideline for Western Canada. Similar numbers are reported for studies in other parts of the world, and he noted that BC should be no different. He indicated that statistics are hard to gather and their interpretation is difficult because of local geological influences plus different definitions of leaking. However, the most critical issue is cementing. He noted that cementing is primarily not a materials problem as cement blends are fairly advanced. The more significant technical difficulty is in removing the drilling mud to prevent contamination of the cement and knowing how to put the cement in the right place.

BCOGC listed similar causes for SCVF leaks, pointing to efforts by the Montney Producers Working Group's 2015 Commission/Industry Working Group formed to review causes of SCVF. They identified gas tight casing connections; practices involving casing centralizers to create standoff from the borehole wall; hole conditioning/cleaning prior to cementing; completion design; cement properties; and cementing procedures as the most likely factors avoiding SCVF. Unconventional wells are susceptible to SCVF due to stretching of casing connectors. It was noted by industry experts during the Panel's visit to an operating site where wellbore completions were being performed that the use of newer, premium connectors has helped to reduce leaks. They also confirmed that failure of the cement itself is likely not an issue, but is a possible path due to small channels and cracks that can develop. Other possible paths for gas and fluid movement include the cement/rock interface and cement/casing interface. This corresponds with observations that SCVF is more commonly encountered where the borehole conditions involve a more rugged wall or where natural fractures are intersected allowing cement to be lost into the fracture zone. Centralizers and standoff are important or else the drilling mud cannot be flushed out properly, and the cement then may be too thin. The industry experts indicated that this is usually an issue in new areas with the first few wells drilled because of lack of experience.

To measure the completeness of the cementing job, cement logs are used, but are not mandatory. Industry experts indicated that 2-3% of wellbores may see a cementing issue that requires a cement/bond log. Cement logs can also be ambiguous or subjective in their interpretation; for example, if the borehole annulus is non-circular through a poor rock interval, or cement is lost into a fracture zone. However, there are rules of thumb for establishing hydraulic isolation or potential for leaks in these cases. Otherwise, the academic specializing in well cementing research confirmed that the use and interpretation of cement logs are generally reasonable. Industry experts also pointed to the use of pressure testing done onsite before beginning hydraulic fracturing operations to ensure wellbore integrity. They indicated that, in general, most challenges are easy to overcome, but require care and attention. It was noted that the Montney Producers Working Group meets annually to share information of the effectiveness of products, equipment and design, and trial results. In their experience, subsequent design and procedural changes have decreased the frequency of SCVFs.

A key knowledge gap identified by industry experts is the uncertainty regarding the source and effects of wellbore deformation events. It was noted that 20-40% of wells experience some form of deformation event. These have been detected in caliper logs, but have only involved deformations, never bursts or ruptures. It was presented to the Panel that deformation events are suspected of being related to geology as they seem to be isolated within the Montney Formation; some areas seem more susceptible than other areas. There are also open questions of whether induced seismicity might in some cases cause deformation events (discussed further in Section 7.3). Despite this uncertainty, the industry experts reported that leaks are rarely seen between the production and surface casing, and therefore, they believe that SCVF is not likely gas from the producing reservoir, but rather is believed to be from upper formations permeating through cementing pathways.

Aside from technical issues, the academic specializing in well cementing research noted that time pressure to perform a job quickly can also contribute to a poor cement job, and that the costs of a poor job are not felt by the driller, or even immediately by the operator; only later when in production. Technical difficulties can be compounded by managerial and organizational factors. However, it was noted by one industry expert that Canada leads the world in environmental regulation stringency, compliance, and transparency related to unconventional gas development (Worley Parsons 2014).

SCVF Testing and Mitigation

BCOGC described to the Panel the requirements for detecting SCVF problems. This involves a very simple "bubble test" whereby a hose connected to the surface casing vent is placed in 1" of water. If a bubble is observed within 10 minutes, a SCVF is identified and the problem must be fixed. A bubble test is required with every completion and abandonment. It is considered by BCOGC to be simple and definitive. The timing of mitigation is risk driven: sour gas is immediate whereas low risk leaks may not be dealt with until abandonment (to avoid perfing good casing, which serves as the primary barrier). It was noted that all mitigation options involve some form of perfing and cementing.

BCOGC also presented to the Panel that operators are also beginning to analyze natural gas samples collected from their producing wells to help build a reference library of geochemical "fingerprints" of BC's different natural gas fields (Geoscience BC's Natural Gas Atlas project). This reference library will help to determine the origin of H_2S and minimize operational risk, as well as to better identify the leaking horizon within a wellbore to more effectively mitigate SCVF.

Venting and Flaring

BCOGC presented a review of the regulations regarding venting and flaring. These prevent operators from venting unless the volume or flow rate is insufficient to support stable combustion and venting does not constitute a safety hazard, venting does not cause off-site odours, and duration of venting is minimized [DPR Section 41]. These regulations also require the operator to have an adequate fugitive emissions management plan[70]; new regulations effective January 1, 2020 include more comprehensive leak detection and repair requirements. Current industry guidance states that plans must meet or exceed the CAPP Best Management Practice for Fugitive Emissions[71].

With respect to flaring, the BCOGC expert pointed to regulations that require the operator to ensure that the duration and volume of flaring is minimized. A permit holder may flare for

[70] Province of BC. New regulations for Leak Detection and Repair: http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg0286_2018

[71] CAPP Best Management Practice for Fugitive Emissions: https://www.capp.ca/publications-and-statistics/publications/116116

emergency purposes or drilling operations, as well as up to 50,000 m^3/year for maintenance or workover operations, including well cleanup and test flaring after hydraulic fracturing. All other flaring must be authorized by permit [DPR Section 42].

Nevertheless, several studies were cited by experts from ENGOs questioning industry practices and the impacts of unconventional gas development. It was noted that the biggest unknown is the level of methane dissolved in flowback that is subsequently released. Howarth et al. (2011) was cited as having found that methane emissions from shale gas development were at least 30% greater than those from conventional gas. However, the study assumed that all gas produced during flowback was vented. BCOGC experts stated that BC has never allowed flowback to be directly vented. Allen et al. (2013) found in a study of methane emissions from flowback events that the highest emissions involved direct venting, mid-range emissions involved flaring of the produced gas, and the lowest emissions were where green completions (i.e. inline testing) was used.

Industry experts in their presentations to the Panel also cited a move towards green completions as allowing them to reduce/eliminate flaring (by up to 90%). This has been enabled through better pumps and piping, and especially through new abilities to handle CO_2 and N_2. This allows them to put the gas into production instead of flaring, using separators and then pumping to the main pipeline. Efforts were also cited of moving towards a greater concentration of wells (i.e. multi-well pads) allowing them to better concentrate impacts.

Still, experts from one ENGO pointed to concerns regarding super-emitters, a small percentage of sites that account for significant emissions, as being a recurring problem across the U.S. and Canada. Because these involve unpredictable events, their volumes are often not accounted for in venting estimates. This perhaps applies more to other points in the gas distribution chain (e.g. gas production and processing facilities), but it was noted that despite substantial improvements in reporting practices in recent years, there still remains significant uncertainty in many reported vented (and flared) volumes at the well site. This was cited as a need for strong Leak Detection and Repair (LDAR) regulations. Best practices from the U.S. point to gas capture instead of venting combined with frequent and comprehensive leak detection and repair. Experts from BCOGC noted that gas produced during well completions is measured through test separators.

6.2.3. Key Findings

There appeared to be consensus that because SCVF, by definition, are contained with the surface casing, and that regulations require this to be extended to depths well below any useable groundwater, that SCVF does not pose a threat to groundwater. The threat to groundwater involves gas migration outside the surface casing, i.e. GM. Thus, SCVF does not pose a risk unless vented to the atmosphere, where it might contribute to air quality and GHG concerns. However, regulatory requirements to test and report the flow rate of SCVFs suggest that they are not a major source of methane emissions relative to other sources (approximately 3% of methane emissions). It was further noted by the Panel that new regulations are in the process of being introduced that will limit fugitive emissions from SCVF to an allowable 100 m^3/day for a given well (reducing emissions from SCVF by approximately 50%).

It was found that the key source of SCVF is related to challenges in cementing and completions. The academic specializing in well cementing research pointed to the shrinkage and cracking that can develop in casing cement over a year from when the well is completed and tested. Identified knowledge gaps include how to design cements, how to place cement and adapt to irregularities in the borehole geometry due to geological heterogeneity and weakness zones, what is the nature of bonding (cement-casing, cement-rock), and what is the influence of wellbore deformation events on well integrity. Several operators pointed to increasing focus and research activities on SCVF to improve wellbore integrity.

Testing for SCVF was found to be simple (i.e. bubble test) and therefore effective. Regulations are in place to minimize venting of leaked gas into the atmosphere. It was noted that these wells are operated with the surface casing vents left open. Although periodic testing is meant to detect SCVF and preventing large volumes of natural gas from being released, it was also noted that smaller leaks might be allowed to persist until the time of well abandonment when they are required to be fixed. This suggests that there is likely a cumulative effect when considering a large number of these wells (10-20%) may have experienced SCVF.

Several positive developments were noted to help better detect and monitor SCVF and venting from sites that will enhance mitigation measures. The Geoscience BC Natural Gas Atlas project, which is nearing completion, will provide fingerprints of 236 oil and gas fields in BC to help trace detected leaks. There is also a need to measure flux from leaking sites, separate from requirements to measure SCVFs if there is a positive test, and Geoscience BC is planning to test fly a “curtain” of drones downwind of a facility to determine the flux of methane leakage from the site. Both industry and non-industry experts pointed to the need for cost effective means and solutions to measure/monitor GHG from facilities.

The move towards green completions was also cited by industry and non-industry experts as significantly helping to reduce fugitive emissions, acknowledging that regulations require collected gas to be flared and not vented. This was cited together with a need for strong Leak Detection and Repair (LDAR) regulations. Again, it was noted by the Panel that new regulations are being introduced, effective January 1, 2020, that strength leak detection and repair requirements. This will include the need for more comprehensive surveys and repair responses when a leak is detected.

6.2.4. Recommendations

The presentation of knowledge gaps related to cementing and completions from multiple industry experts emphasized the need for additional research on these topics. It was explained that past research has delivered important learnings, but these are now showing a need to expand to field-scale research experiments because lab-scale experiments do not scale properly. Research in general has proven valuable in driving several important technological advances. This should continue to be encouraged to both drive the development of leading edge technologies and their use.

It was presented to the Panel that BC, together with the other provinces, have been left to choose to either adopt recent Canadian regulations to reduce fugitive emissions or draft their own to meet or exceed the stated targets. BC regulations should include similarly strong and comprehensive Leak Detection and Repair (LDAR) requirement. It is recognized by the Panel that new regulations are being introduced for BC that strengthen LDAR requirements. However, it is also noted that federal regulations[72] regarding reduction of gas release and venting limits in the oil and gas sector specify, "*An upstream oil and gas facility must not vent more than 15,000 standard m^3 of hydrocarbon gas during a year.*" Exceptions are made for the case where venting is necessary "*to avoid serious risk to human health or safety arising from an emergency situation.*" In comparison, the new BC regulations regarding well surface casings will allow up to 100 m^3/day, which means potentially a leaking well can exceed the federal limit of 15,000 m^3/year. With respect to LDAR, the new federal regulations specify the period for inspections for an "*equipment component at an upstream oil and gas facility*", to be at least three times per year and at least 60 days after a previous inspection. The new BC regulations specify that wells producing from an unconventional zone must undertake one "comprehensive survey" per year within nine months of the previous survey. It is not clear to the Panel if there are nuances or conditions prescribed under different definitions and subsections that bring the new BC regulations for SCVF into line with federal requirements.

In either case, efforts to better detect and monitor SCVF are encouraged by the Panel. The Panel supports the notion that robust monitoring, reporting, and enforcement will help to drive innovation.

The Panel also found that First Nations' and public concerns are partly owing to questions of transparency and the lack of industry data being made available to the public. BCOGC has helped lead the move towards more transparency; however, it is still a limiting issue, especially around questions of data confidentiality. The Panel recommends that industry data regarding SCVF be made publicly available, including both detected/measured leaks and monitoring and mitigation measures taken. In several cases, it was communicated to the Panel that known leaks were being allowed to persist and that they would be dealt with at the time of well abandonment. Although it is understood that mitigation measures that require perforating the casing are undesirable while the well is still in production, the Panel questions whether it would be possible to capture and use this gas as an alternative solution until the well is abandoned.

[72] Canadian Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector): https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-66/page-5.html#docCont

(Note that recommendations regarding the use of pneumatic devices are discussed in Section 6.3).

6.3. Gas Migration (GM)

6.3.1. Concerns Raised

Unlike SCVF, because Gas Migration (GM) involves the movement of natural gas outside the surface casing, concerns primarily center on the potential for sustained impacts to groundwater resources, but also air quality, GHG, and cumulative effects. CAA (2014) suggest that GM is the greatest threat to groundwater.

Representatives who spoke on behalf of Treaty 8 First Nations raised concerns regarding the impacts of natural gas leaking into aquifers on their Treaty Rights, especially in the context of cumulative effects and mixing of contaminated groundwater with surface water. It was noted that if an Elder says that water from a previously viable source should no longer be drunk or fish be eaten, that is sufficient for the community to do the same and is indicative of water contamination due to unsafe oil and gas practices. They said that this change in behaviour is an infringement on their Treaty Rights, and that it is a "*universal concern across Treaty 8 that you can no longer trust the water, whether due to oil and gas, mining, or forestry.*" The representatives who spoke on behalf of Treaty 8 First Nations explained that "*if their people need to always carry freshwater with them, for example when camping, hunting, etc., instead of being able to rely on local sources, this has real impacts on what they can and cannot do to enjoy the land.*"

Concerns were also expressed by ENGOs regarding the limited ability to track GM unless it appears at the wellbore. GM can be monitored near the well head, but is much more difficult to detect or monitor away from the wellbore both on surface and at depth. Representatives who spoke on behalf of Treaty 8 First Nations noted that there are no requirements to monitor the possible impacts of GM on shallow aquifers at depth, only at surface (e.g. operators are required to carry out pressure tests). Industry experts acknowledged uncertainty in how to identify GM and where to put monitoring wells to confirm (or refute) there is an issue. They explained that without accurate models that provide knowledge of where gas migrates in the subsurface, monitoring wells cannot be properly placed.

The Panel notes that these concerns are complicated by key knowledge gaps regarding potential pathways for upward migration of hydraulic fracturing fluids, gases and formation water (brine) from deep shale gas reservoirs to shallow aquifers. Lefebvre (2016) notes that there is general acceptance that without preferential pathways, it is very unlikely that fluids would migrate vertically over large distances (kilometres) through the geological units above a shale gas reservoir. Still, many reports by expert panels and review papers present conceptual models showing the fluid migration along large fault and fracture systems and other pathways (i.e. wellbores) and gas leaking into aquifers at shallower depths (e.g. CCA 2014; EPA 2015; Figure 33). The topic of vertical migration of fluids was addressed in Section 4.3.

With respect to GM and GHG, ENGO experts emphasized to the Panel in their presentations that tonne for tonne, methane traps 84 times more heat over 20 years than CO_2. This is coupled, in their opinion, to key concerns that emissions are self-reported by industry and that there is an overall lack of transparency of data and information collected by the BCOGC and industry. It was noted that publicly available information on BCOGC websites is not very comprehensive and hard to synthesize. They explained that the cost of equipment to do necessary fieldwork and research can be prohibitive, and access to oil and gas sites is often restricted. This makes it difficult to know the true extent of gas migration in NEBC.

6.3.2. Summary of Expert Evidence Presented

Leaking Outside of Wellbores

BCOGC presented regulations and experiences to the Panel involving wellbore design and completions to protect against GM and potential contamination of shallow aquifers. It was explained that surface casing must extend below the depth of useable groundwater and be cemented to surface [DPR Section 18(3, 4)][73]. This provides isolation between the well and usable groundwater. Surface casing depth is specified in the well permit application; operators wanting to reduce this depth must justify their request, subject to review of the well permit. It was explained to the Panel that wellbores will include one or two intermediate casings when needed to isolate problem zones during drilling, helping to protect against GM while also helping to control drilling. BCOGC indicates that only 10% of wells include intermediate casing. Furthermore, operators are not allowed to conduct hydraulic fracturing at depths less than 600 m [DPR Section 21]. Given that deep unconventional resources are the focus of current development, operations are well below this minimum depth.

With regards to the known scale of GM, BCOGC cited 144 wells identified as exhibiting GM (as of January 2018), representing 0.5% of total wells drilled. It was said by the BCOGC expert that, "*these are largely due to shallow gas above the surface casing shoe and are not associated with hydraulic fracturing. In fact, the significant depth of the targeted shale gas formations (>2,000 m) provides considerable isolation between the deeper hydraulic fracturing operations and near-surface shallow aquifers.*"

The BCOGC expert then explained to the Panel that BC regulations require reporting of an occurrence of GM [DPR Section 41(4.1)]. On discovery of GM, the operator must immediately notify the BCOGC, evaluate the cause and source, and complete a risk assessment. The risk assessment should document information to demonstrate a low risk gas migration scenario or

[73] OGAA Drilling and Production Regulation: http://www.bclaws.ca/civix/document/id/complete/statreg/282_2010

provide information as a basis for determining further investigation, monitoring, management, and/or mitigation measures. Industry recommended best practices requiring an operator to contact owners of other wells in the area to initiate mitigation measures if a hydraulic fracturing operation shows connectivity with an existing adjacent well, has been working well with good cooperation.

Operators are required to take all reasonable measures to minimize the risk of loss of well control or integrity. Industry experts cited that hydraulic fracturing treatments are designed at 80% of the burst pressure of the casing to ensure this. Communication between adjacent wellbores is seen on a regular basis, including hydraulic fracturing fluids having been seen in producing wells, as have been kicks (i.e. hydraulic fracturing into an adjacent wellbore being drilled).

In assessing the risk of GM, BCOGC suggests that the highest risk is related to shallow sourced gas moving upward outside of surface casing, but that it is also possible for deeper gas to migrate due to blowouts and kicks from over-pressure at the surface casing shoe and bypassing surface casing. Industry experts noted that to mitigate risk, surface casing is designed for kick resistance. In addition, they pressure monitor in real-time all of their neighbouring wells during hydraulic fracturing. Should the observed pressure response exceed 90% of the wellhead pressure rating, a shut-down protocol is initiated. Through this monitoring, they have routinely seen pressure communicated between wells on the same pad, as well as between wells up to 800 m away.

An academic who specializes in wellbore geomechanics indicated that cemented wellbores can leak outside of the casing, but it is important not to conflate probability and risk. Although leaking wells certainly exist (i.e. probable), the consequences must also be weighed in evaluating risk. This includes consideration as to whether natural gas is actually toxic in the small quantities involved with these leaks also considering that most sites are remote and effects decay with time.

Direct Pathways for Vertical Gas Migration

BCOGC identified as an issue the question of direct pathways. This topic with respect to the vertical migration of hydraulic fracturing fluids was addressed in Section 4.3, and similarly applies to GM. The Panel also recognizes that the likelihood for GM along a geological pathway, and/or wellbore pathway, is higher for gases than liquids.

In discussing this issue, BCOGC indicated that the necessary circumstances for GM to occur are a gas source (at any depth), a well integrity issue that intersects the gas source, and a combination of gas pressure (a build-up of pressure can force gas up and around surface casing), well integrity, and geologic characteristics that permit the movement of gas to the usable groundwater zone or into the atmosphere. The latter is referred to as a direct pathway. It was noted by BCOGC in their presentation that while the concept of a direct pathway may remain a public concern, research suggests that at the depths of hydraulic fracturing in BC, the potential for a pathway connection to the usable groundwater zone due to hydraulic fracture propagation is negligible. In addressing the potential pathways suggested by the CCA (2014), BCOGC highlighted that a pathway through the overburden rock (pathway 3 in Figure 33) is hypothetical and no known cases of migration of hydraulic fracturing fluids from a deep shale zone to the groundwater level directly through the overburden rock has been observed. The remaining pathways are related to wellbore integrity.

As presented and discussed in Section 4.3, it was cautioned by an expert from the Geological Survey of Canada, that although the intermediate zone with a thickness of approximately 2,000 m serves as an efficient barrier against GM, the intermediate zone also represents a major knowledge gap as data collection tends to focus on either the deep shale gas formations or the shallow aquifer system (i.e. the intermediate zone are data poor). Thus, it was concluded by this expert that although the possibility of a large fault zone acting as a large-scale flow path seemed very unlikely (in that study area), the existence of large-scale preferential flow pathways could not be unequivocally ruled out. Again, supporting details and an in-depth review by the Panel are provided in Section 4.3.

Another potential pathway identified is through hydraulic fracturing that intersects an adjacent well. Lefebvre (2016) indicates that this potential is plausible, and incidents have been reported on impacts of hydraulic fracturing on adjacent wells, which led to Alberta developing regulations aimed at minimizing such incidents, notably through minimal distances of fracking from existing wells and the verification of the integrity and completion records of nearby wells. Experts presenting for an ENGO also pointed to inadequately sealed or abandoned wells as another potential pathway. Still, they noted that handling of wastewater is the key contamination risk pathway for shallow aquifers.

BCOGC indicated that experiences show that wells with known GM can be spatially clustered, pointing to the influence of region-specific factors. It was acknowledged by both industry and non-industry presenters that there is a need for a better sense of occurrences and incident rates.

GM Source

The expert from the Geological Survey of Canada also presented data from the same study area in Eastern Canada suggesting that the vulnerability of shallow aquifers is more related to near-surface casing defects. This conclusion was drawn from geochemical testing of the source of methane found in shallow aquifers nearby gas exploration wells. It was explained that groundwater is an important source of water supply in the region and that dissolved methane in the water was ubiquitous. A number of investigative boreholes were drilled to sample the groundwater at depth, including two wells located near natural gas boreholes, two targeting faults as possible conductive pathways, and nine located on natural gas well pads. In presenting the data, published in Bordeleau et al. (2018), it was explained that methane is affected by different processes: biogenic (bacteria) and thermogenic (bedrock). In this case, the geochemical analysis made it possible to determine the source (local shallow bedrock gas versus migrated deep formation gas), which was found to be critical for evaluating aquifer vulnerability to shale gas activities. The results showed that the source of the methane in the groundwater was generated within the shallow aquifer (microbial gas) or was released from the shallow bedrock matrix (thermogenic). Most importantly, the known regional faults cutting through the shale succession were not seen to convey thermogenic gas from greater depths (such as the Utica Shale) toward the surface.

The hydrogeology expert from FLNRORD reported data from an ongoing aquifer characterization project in NEBC. This involved the sampling of both private wells (>390) and several dedicated observation wells. In 2018, 24 wells showed elevated dissolved methane. However, the chemistry of these wells indicates that all are dominated by surficial recharge and groundwater is not mixing with deeper upward migrating water. Nevertheless, carbon isotopic analysis is needed to clearly identify the source of dissolved methane. It was indicated that more research is needed with more data, controlled water chemistry testing, and monitoring of seasonal variability. Also, a long-term monitoring plan is needed together with a central database to store data.

Industry experts noted that Alberta is consolidating all government and donated industry data and reports as a means to address the lack of baseline data. It was emphasized that BC needs more standardized monitoring and sampling protocols. The absence of baseline data was also noted by several industry experts who indicated that CAPP is helping to create a water quality database. CAPP best practice guidelines require all water wells within 250 m of a hydraulic fracturing operation to be sampled, with some industry experts noting that their operations require all wells within a 3 km radius of a hydraulic fracture to be sampled. It was further noted that for some operators, water wells in their areas are sparse where the groundwater source is of poor quality.

Detection and Impacts

Challenges regarding the detection and monitoring of GM were presented by academics who are currently developing a research test site near Hudson’s Hope to investigate the effects of GM on shallow aquifers. This was preceded by a visit from the Panel to the test site (Figure 34). Their work is also looking at testing different sensors and methodologies for methane detection (e.g. by drone on surface, and using multi-level piezometers at depth). The tests they are carrying out involve the injection of natural gas representative of the Montney Formation into an aquifer representative of the region (confined, 15 m of silty fine sand beneath 12 m of clay, water table at 3 m depth) at a depth of 26 m. They will then monitor the groundwater and surface emissions response for a minimum of 1 year.

Figure 34. Hudson's Hope Field Research Station investigating natural gas migration and interactions in a shallow aquifer. Photos taken during the Panel's site visit.

The academics pointed to the state of knowledge regarding the impacts of methane on shallow aquifers as being highly contested. This is often due to the lack of baseline data and the ubiquitous presence of natural methane in the subsurface (e.g. Darling and Goody 2006). Another complicating factor is that there are numerous contributing factors/causes including geographical location, geology, drilling and completion methods, and surface casing pressure and depth (e.g. Ingraffea et al. 2014; Bachu 2017). Thus, GM is a very regional/jurisdictionally variable problem.

With respect to detection, these experts noted that surface-based detection is easier and more reliable than at depth. Infrared methane detection is 2-3 ppm, and measurements are more repeatable than previous methods. However, current monitoring practices are likely inefficient or sub-optimal (Cahill et al. 2017. If detected, the origins of the methane can be reasonably traced (e.g. Darrah et al 2014). Still, significant uncertainty accompanies its environmental impact, persistence and ultimate fate in groundwater aquifers. Representatives who spoke on behalf of Treaty 8 First Nations raised similar concerns regarding limitations in detecting GM, especially in the subsurface, and the cumulative effects of fugitive emissions.

An expert in hydrogeology suggested that no large-scale, regional issues associated with GM have been identified to date. Where migration of gases has been detected, these generally do not extend beyond 1 km from the borehole (Jackson et al. 2013). Even then, these studies are often proved inconclusive and controversial. The challenge is really one of risk identification and risk management given the remoteness and low population density of the region and the highly regulated nature of the industry.

With respect to impact and risks, the academics noted that methane is natural, non-toxic and poses no health risk alone. However, oxidation reactions and pathways have been shown to degrade groundwater quality (Cahill et al. 2017; Schout et al. 2018), or it may be accompanied by other hydrocarbons or brine (Warner et al. 2012). They also indicated that the true levels of incidence and occurrence are unknown and the true risks and long term impacts are poorly understood, especially in NEBC due to complexity and lack of research.

Impacts and risks associated with GM were also key concerns of representatives who spoke on behalf of Treaty 8 First Nations. These included a key concern and objection that human health was not part of the Panel's mandate. As indicated at the outset of this report, the Panel sought input from experts in toxicology and public health. Section 7.1 of this report discusses risks to human health.

6.3.3. Other Evidence Considered

As noted above, methane is seen to be non-toxic and poses no health risk alone. However, a second mode of groundwater contamination that could evolve from GM contamination is oxidation of fugitive methane via bacterial sulfate reduction. Oxidation reactions and pathways have been shown to degrade groundwater quality (Cahill et al. 2017; Schout et al. 2018).

Evidence for dissimilatory bacterial sulfate reduction of fugitive methane near conventional oil wells in Alberta includes sulfide generation and ^{13}C-depleted bicarbonate, with lower residual sulfate concentrations relative to the regional groundwater (Van Stempvoort et al. 2005). Bacterial sulfate reduction reactions due to the presence of fugitive methane could trigger other processes such as reductive dissolution of oxides in the aquifer that would mobilize redox sensitive elements such as manganese, iron, and arsenic from the aquifer matrix and further reduce groundwater quality. As well, low levels of arsenic and other contaminants have been measured in some drinking water aquifers in Texas, and these were suggested to be linked to contamination from the underlying Barnett Shale, although evidence for a direct link to the Barnett remains uncertain (Fontenot et al. 2013).

6.3.4. Key Findings

Although methane is considered natural, non-toxic and is suggested to pose no health risk on its own, it was demonstrated to the Panel that oxidation reactions and pathways can lead to groundwater quality degradation. This was certainly the experience related to the Panel by representatives who spoke on behalf of Treaty 8 First Nations. As such, the topic of gas migration (GM) is an important one that links with findings regarding water quality in Section 4 of this report.

Regarding GM, the Panel found this to be a complex and multi-disciplinary problem. Under typical conditions, high-permeability preferential fluid migration pathways appear to be necessary to allow upward fluid flow from depths where hydraulic fracturing and gas production is being carried out to shallow depths where fresh water aquifers are generally found. Concerns that hydraulic fracturing may provide such a conduit are not supported by data or the general nature of these operations. As reported by Zoback and Arent (2014) based on their experiences in the U.S., GM from an exploited shale gas reservoir cannot occur because: 1) shale gas exploitation typically occurs at great depths (between 2 and 3 km), whereas the extent of fractures created by hydraulic fracturing is generally limited to 600 m (with a small probability of actually extending over 350 m), and related microseismic events are only seen at distances exceeding 1 km from aquifers; and 2) because gas production reduces its pressure in the shale, thus limiting the driving force for gas flow.

However, there is potential for gas to migrate vertically upward via other pathways, such as along natural fractures and fault systems in the rock, and/or along the outside of wellbores. As presented to the Panel, data for the intermediate zone between the shallow aquifer system and deep formations where shale gas is being produced are poor, especially in NEBC, and this lack of data represents a major knowledge gap.

Other knowledge gaps regarding shallow GM are slowly being addressed, but there are still limitations regarding the absence of baseline data and understanding of fundamental science and natural occurrences, especially specific to the NEBC context. This is hampered by a limited ability to track GM unless it appears at the wellbore. Industry research is often site-specific, and there is an absence of integrated studies. The Panel notes that there is promise in new initiatives to address key knowledge gaps through field-based experiments, as well as research testing of new methane detection methods and tools. These offer promise in starting to narrow the considerable knowledge gaps regarding the impacts of the subsurface geology and its heterogeneity on GM, in addition to understanding interactions during GM (transport fate – i.e. attenuation).

More effective, science based regulations are needed. These can be developed through increased research in a BC context to optimize monitoring and detection methodologies, and to enable true risk to be understood and managed. New technologies enabling green completions are seen by the Panel to be an important positive. BCOGC indicates that green completions are already used on 85% of wells. Continued integration of new technologies into regulations and best practices, and requiring more robust monitoring, reporting, and enforcement will help drive further innovation.

Although not related to GM, but related to the broader concern of fugitive emissions, a technological need was identified by experts from an ENGO to take advantage of hydroelectricity development in NEBC as a green option to electrify and replace pneumatic controllers, which are widespread in their use and run off natural gas. These were cited as being a significant source of fugitive emissions. It is noted by the Panel that new regulations[74] will come into effect starting January 1, 2020, regarding the use of pneumatic devices.

6.3.5. Recommendations

In relation to GM that has been detected at the well head, BC's oil and gas sector is reasonably well regulated. However, regulations need to be accompanied by enforcement and transparency. A key challenge expressed by a number of ENGO representatives is an overall lack of transparency of data and information. Similar to the case of SCVF, the Panel recommends that industry data regarding GM be made publicly available, including detection, monitoring, and mitigation measures taken.

The detection and monitoring of GM away from the wellbore and at depth is much more problematic. It was expressed by all experts presenting on the topic of GM (industry, ENGOs, representatives who spoke on behalf of Treaty 8 First Nations, etc.) that this was a major challenge. Near the well head (at surface), the detection of GM can be triggered by visual cues observed by workers on site (e.g. bubbling standing water). In contrast, the detection of GM away from the well head or especially at depth is extremely difficult given limitations in remote sensing detection capabilities or a lack of definition as to where to target deeper groundwater monitoring wells. It is recommended that research be directed and supported to develop and

[74] DRP amendments effective January 1, 2020:
http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg0286_2018

improve GM detection capabilities using remote sensing technologies to allow initial screening detection over large areas. This will help to identify and allow for more focussed research and monitoring where leaks away from the well head are discovered. Also required is baselining and monitoring near potential sources of GM contamination. It was recommended by one expert that there is a need for research on methods and tools to determine what constitutes an adequate number of sampling points (statistical power), proper and consistent data collection/handling protocols (QA/QC), and constituents to track (major and trace elements).

At depth, similar key knowledge gaps persist regarding the characteristics of the intermediate zone and the potential for gas to migrate vertically upwards from deep shale gas producing formations via geological and/or wellbore pathways. The Panel likewise recommends that this knowledge (and data) gap be the subject of a concerted research effort. It is important that research extend beyond conceptual numerical modelling studies and encompass the collection of, or access to, high quality geological data targeting the intermediate zone.

The field-based research study at Hudson's Hope targeting the shallow groundwater system is a prime example of the level of research effort required to address knowledge gaps. Knowledge gaps can be closed by field-based studies. Research should target a better understanding of the incidences and causes of GM in BC, and provide data to investigate the need for and approaches for groundwater monitoring at natural gas well sites. It can be argued that such efforts should perhaps be preceded by a priority-based roadmap for future research to support a coordinated research approach moving forward and foster knowledge translation to practical applications.

It was also expressed to the Panel that more research is needed to evaluate the potential impacts of GM and support the identification of readily available data that can be used as risk criteria to assess individual cases of GM. Research may be useful to inform a risk-based approach to GM and groundwater monitoring. All research pertaining to well integrity and groundwater should consider relevant multidisciplinary aspects, and regional/jurisdictional aspects including regulatory and oil and gas development history.

6.4. Long-Term Integrity

6.4.1. Concerns Raised

Representatives who spoke on behalf of Treaty 8 First Nations also identified concerns that SCVF and GM issues not only encompass the period of production, when monitoring efforts are active, but also extend into legacy effects due to the deterioration of the integrity of these wells over time, especially when they are no longer producing or have been decommissioned. They stated that areas impacted from drilling activities 50 years ago are still being cleaned up, and believe that animals are getting sick from these areas. They indicated that protection for animals around old sites is not legislated, and photos were shared with the Panel of animals who have died due to inadequate protection around abandoned sites. Key knowledge gaps in the form of questions include who will keep monitoring these wells, who will fix them in the future, and who will look after them in 100-200 years when they need to be fixed/sealed again? Also, what is the potential risk of a loss of wellbore integrity due to natural or induced seismicity events that could lead to fugitive emissions?

Similar concerns were expressed by these representatives regarding older wells that have been re-purposed for wastewater disposal (as discussed in Section 4.5). They questioned the standards required for re-purposed wells in relation to their long-term well integrity and potential for gas emissions.

6.4.2. Summary of Expert Evidence Presented

During the Panel Proceedings, BCOCG described the regulations defining the well's status and operator's responsibilities, citing the DPR under OGAA. Active wells include those being drilled or producing oil or gas, and also include injection (fracking) wells, disposal wells, and observation wells. A well is inactive if it has not been producing for 12 months (6 months if it is a sour gas well). Within 60 days of the well becoming inactive, the operator must suspend the well and do so in a manner that ensures the ongoing integrity of the well. Suspended wells may still have equipment on site as the operator may resume drilling in future, but until the well returns to active status, the operator must establish a program of inspections sufficient to ensure the ongoing integrity of the well.

Once a formation is depleted and no longer capable of producing at a profitable level, the well is abandoned. Well abandonment means to permanently plug a well with cement to prepare the site for restoration to its pre-drilling conditions (deserted wells as per the common definition of abandonment are referred to as orphan wells). The DPR requires operators to plug abandoned wells in a manner that 1) ensures fluids will not leak from the well, 2) excessive pressure will not build up within the well, and 3) the long-term integrity of the wellbore is maintained. The abandonment for single wells versus multiple wells (i.e. on multi-well pads) is similar, but the latter may be more intensive due to a greater number of wells at the site. Remediation is required where contamination is present. BCOGC indicated that the end goal is a Certificate of Restoration (CoR) where, following any required remediation, the site is permanently dismantled, restored, and left in a safe and secure condition. The CoR is issued by BCOGC certifying that the abandoned wellsite has been restored to meet regulatory requirements. As of December 2016, there were 2,730 abandoned and 6,795 inactive wells, versus 10,390 that were still active and 4,810 that had received their CoR (BCOGC 2016)[75].

Experts from one ENGO discussed concerns regarding the rate at which CoRs have been issued in recent years compared to the large number of inactive and abandoned wells. They suggested

[75] BCOGC Drilling Activity Fact Sheet: https://www.bcogc.ca/node/11469/download

that based on their analysis of BCOGC data that 10 to 20% of all active and suspended oil and gas wells leak. They also presented data from Atherton et al. (2017) who reported that 47% of active wells they surveyed emitted methane-rich plumes above the minimum detection threshold used (0.59 g/sec). Abandoned wells were found to be associated with emissions at 26% of the sites sampled.

A BCOGC expert indicated in his presentation to the Panel that they subsequently inspected all abandoned wells reported by Atherton et al (2017) as emitting gas, and did not detect any methane emissions. They also noted that two categories of emitting wells stated in the study (cancelled and well authorization granted) do not actually exist. A further criticism of this study raised by the BCOGC expert was that the study did not distinguish between thermogenic and biogenic gas as the source of emissions detected. Thermogenic methane is generated under high temperatures (i.e. significant depths) and is indicative of the natural gas being produced from deep shale gas reservoirs; whereas biogenic gas is produced by microbes in low temperature, shallow surface environments (Stolper et al. 2014). The latter is unrelated to natural gas operations and can be ubiquitous in the shallow surface in some areas.

During the Panel Proceedings, BCOGC reported that problems with abandoned wells are typically associated with older wells, and not as much with unconventional gas wells, because the latter were drilled and completed under stricter regulations, most notably the requirement that the surface casing be cemented back to surface. Older conventional wells are more likely to leak due to older production casing cementing requirements.

The larger unresolved question is that of integrity of both older and newer wells for periods longer than the current experience base, for example 100 or 200 years. Various industry experts acknowledged that well integrity and behaviour over time is a key knowledge gap and recognized risk. Their data suggests that long-term integrity issues are most likely linked to poor quality work. Less likely is the degradation of the cement over time leading to integrity problems. Microannulus (the shrinking of cement leading to a micron-scale annulus) is a common occurrence, but has not been seen to cause SCVF/GM leaks. Another industry expert indicated that Canada is a leader in cement testing and research, and that NEBC does not see the high temperatures that have been shown to weaken cement over time. In audits of sites that have been issued a CoR, BCOGC reports that of the 41 sites audited since 2012, one problem was found. In relation to wells re-purposed as disposal wells, BCOGC noted that to re-purpose an older well for wastewater injection purposes, the application must include casing inspection results, cement logs, and pressure testing results. Re-purposed wells must undergo the same testing/requirements as if it had been drilled for disposal purposes at the outset, as previously stated in Section 4.5.

Representatives who spoke on behalf of Treaty 8 First Nations questioned the influence of induced seismicity on wellbore integrity, pointing to a BCOGC report from December 2014 of an induced seismicity event in the Montney on May 27 or 28, 2013 that damaged a wellbore 1.5 km away from the event epicenter. In addition to the potential for future induced seismicity events related to hydraulic fracturing activity, the region also experiences natural tectonic earthquakes (Atkinson et al. 2016). The reactivation of a fault through which a wellbore passes, or active slip along a plane of weakness in response to a nearby earthquake, has the potential to rupture multiple wellbores. For example, Dusseault et al. (1998) recount the shearing of hundreds of oil well casings in the Wilmington Field in California in response to several shallow earthquakes of M2 to M4 triggering shear movement along a confined thin bed of clay shale through which the wellbores passed.

6.4.3. Other Evidence Considered

When asked by the Panel about wellbore integrity in relation to fugitive emissions, industry representatives acknowledged that well integrity over time (both the deterioration of casing and cement) is a key knowledge gap and recognized risk. This was also the conclusion of the CCA (2014) in their report in finding that fugitive emissions from improperly formed, damaged, or deteriorated cement seals is an unresolved problem that continues to challenge the industry. Cement is susceptible to degradation over time, especially due to higher temperatures at depth or changing temperatures over the operating life of the well (cement fatigue), but the nature and rate of this deterioration are poorly understood (Nelson and Guillot 2006; Teodoriu et al. 2012; Wilcox et al. 2016). Cracking, shrinking, or deformation of the cement in response to this deterioration can reduce the tightness of the seal around the wellbore, allowing fluids and gases to escape into the annulus between the casing and formation, and subsequently migrate to shallow aquifers or to the surface and into the atmosphere (Dusseault et al. 2000).

The Australian Council of Learned Academies (2013) state that the long-term integrity of a cemented and plugged abandoned well (beyond 50 years) is a topic where more information is essential. For example, Ewen et al. (2012) report on the findings of an ExxonMobil-funded panel in Germany, and state "*the industry's eight decades of experience with the long-term stability of cement shows that gas well cementing does not remain leak-proof indefinitely*." It can be reasoned then that over time, the potential for loss of wellbore integrity increases as steel corrodes and cement shrinks, cracks, or debonds from the casing and rock (Hays et al. 2015). Dusseault et al. (2000) point to cement shrinkage as the most likely mechanism for gas leakage after abandonment, explaining that cement shrinkage leads to circumferential fractures that then propagate upward by the slow accumulation of gas under pressure behind the casing. Over time, this will allow the buoyant gas to leak along the annulus between the production casing and the formation. This deterioration explains why older wells leak more.

Other processes can lead to cement shrinkage. High salt content in formation water can lead to osmotic dewatering of the cement slurry during setting and hardening, resulting in substantial shrinkage as well as differential setting/shrinking along different horizons along the wellbore in response to different formation water chemistries (Oyarhossein and Dusseault 2015). Goodwin and Crook (1992) and DeAndrade and Sangesland (2016) point to cement cracking around wellbores in response to significant temperature changes. Lecolier et al. (2006) showed through testing that acidic conditions created by the presence of hydrogen sulphide gas (H_2S) can lead to severe degradation of cement strength. In many of these studies, the authors caution that the duration of the laboratory-scale tests performed are in days and not years (cement deterioration can be very slow), and that the test conditions are highly simplified compared to the complex conditions and longer time periods that are of interest.

Similar conditions (i.e. temperature, brine, H_2S) can contribute to the corrosion of a well's steel casing. However, outright loss of well integrity through which gas escapes from the well and into the adjacent formations is considered to be very rare (King and King 2013). In a study of data involving more than 600,000 wells worldwide, King and King (2013) found that oil, gas and disposal wells have an overall leak frequency related to true well-integrity failure ranging from 0.005 to 0.03%, with older wells having a higher leak frequency owing to simpler well designs that involve fewer barriers. They note that newer wells are constructed with multiple barriers (e.g. nested cemented casing strings), for which one or more barriers in a properly designed and constructed well may fail without creating a pathway for leaking.

It is noted that through the identification of these issues and their effects on wellbore integrity, approaches can and have been developed to solve many of the commonly identified problems (Dusseault et al. 2000). For example, new cement formulations and additives have been used to reduce cement shrinkage and the effects of brine and formation water geochemistry. Proper cement design and good operational practices can mitigate short-term leakage owing to difficulties with cement placement Taylor et al. (2016). However, these do not address the uncertainty related to long-term integrity where leaking may not occur until years after initiation of production. Boothroyd et al. (2015) found in a study of decommissioned wells in the UK up to 79 years old, that integrity failures were detected after decommissioning but that when well integrity is a problem, it occurs early on in the decommissioned life of a well (within 10 years).

6.4.4. Key Findings

Experiences with the long-term integrity of wellbores is limited, and represents a major knowledge gap. On the one hand it is accepted that well completions and cement quality have reached very high levels in today's practice. As noted by one industry expert, Canada is recognized as a world leader in wellbore cement testing and research. However, the issue of long-term well integrity also encompasses older practices and industry experts concede that further research is required to more fully understand the long-term degradation of cement and casing steel under subsurface conditions. Wells are designed with multiple barriers guarding against direct breaches of the wellbore, but cement is known to shrink over time, opening up possible pathways through the cement and/or cement-casing interface. Good cement design and operational practices can easily mitigate short-term leakage. However, the question (and knowledge gap) is one of long-term performance of cement and steel under the harsh temperature and water chemistry conditions existing at depth.

The Panel found that published data on the long-term performance of wellbores, casing and cement are scarce. In their report, CCA (2014) emphasize that "*given the tens of thousands of shale gas wells that may be drilled in the next 50 to 100 years, there is a need for credible research into these important questions, undertaken by research that is independent of influence from sectors with vested interests.*" This points to a clear need for the continued study of well integrity, and recognition that the factors that can adversely affect integrity may vary both locally and regionally according to the site specific geological conditions (e.g. formation water chemistry, quality of well completions and cementing job, etc.).

Given the long time periods and complexity involved, the recommendations in Ewen et al. (2012) based on the findings of the Exxon-organized panel are especially noteworthy that: 1) on an operational level, abandoned and sealed wells need to be monitored so as to detect any gas or contaminant emissions early enough to take necessary countermeasures, and 2) on a research level, demonstration projects are required and should be intensively monitored, focusing on the geomechanics of fracture propagation, well integrity, and contaminant occurrence, transport, and fate.

6.4.5. Recommendations

There appears to be a clear need for targeted research to address significant knowledge gaps related to the long-term integrity of unconventional gas wells. This research needs to expand beyond the lab-based research of cement performance and the empirical studies of leaking wells with little to no subsurface data, and target high-quality data collection and interpretation involving instrumented wellbores and sites, tracking surface and subsurface conditions through the life of a well from green field baseline to completions to operating and eventually decommissioning. This research needs to be multidisciplinary and placed in the public domain.

7. Risk

7.1. Impacts on human health

7.1.1. Concerns Raised

Significant concerns were raised about the toxicity of hydraulic fracturing fluids (including flowback water and wastewater) and potential risk to humans and the environment. As discussed in Section 4, there is concern about specific chemicals in water (e.g. barium, lead sulphate, NORM, and TENORM). Representatives who spoke on behalf of Treaty 8 First Nations made several references to "scum on tea", and while no scientific data are available to determine the nature of the scum, there is a general mistrust of the water and people no longer drink from streams. Because animals are always on the move, there is added concern that animals in a non-industrialized area might have earlier been in a contaminated area and are sick.

As mentioned in Section 1.1, human health was not specifically included in the terms of reference for this scientific review; however, the Panel considered human health to be implicit in environmental impacts. As none of the Panel members has expertise in human health, the Panel sought input from experts in toxicology and public health. Public health takes into account physical, mental, and social well-being, and so has broad scope encompassing not only toxicological impacts, but also impacts to emotional and spiritual wellbeing. For this reason, the Panel carefully considered First Nations' right to "peaceful enjoyment." The Panel acknowledges Indigenous peoples' spiritual, rather than solely material, connection with water.

The focus of this section is on toxicology and broader risks to public health. It incorporates evidence from epidemiological and human health risk perspectives, as well as from scientific studies that the Panel was referred to. The Panel notes that water quality guidelines and objectives are developed for various parameters to protect water used for drinking. BC uses the "Most Sensitive Use Approach." Generally "aquatic life" is the most sensitive use of water (to chemical substances). When aquatic life is protected, other uses (e.g. drinking water) are protected as well. BC adopts guidelines for drinking water quality from Health Canada. In addition, there are water quality guidelines for microbial indicators for protection of human health. Given that the greatest concern surrounds chemical contaminants in water in NEBC, water quality guidelines and objectives are discussed in detail in Section 7.2 in the context of aquatic ecosystem impacts.

7.1.2. Summary of Expert Evidence Presented

Hydraulic fracturing fluids contain additives that include pH adjusters, scale/corrosion inhibitors, biocides, etc. that all performs specific functions. Wastewater also includes these chemicals in addition to substances from the producing formation (e.g. salts, hydrocarbons, NORM). All fluids appear as mixtures and depend on the producing formation and the type of operation. A significant number of chemicals are disclosed on FracFocus.ca.org (over 1,000 discrete chemical substances are used in hydraulic fracturing operations); however, which ones are used depends on a host of factors. Moreover, there is a sizeable number of additives that are not disclosed for proprietary reasons. The expert in toxicology stated *"the challenge as a toxicologist is that there is no 'standard formula' for these fluids*." From a basic chemistry perspective, some chemicals will degrade over time or may undergo chemical reactions, and the products may be different. Therefore, it is hard to identify what chemicals may be present in the environment. There is also no standard formulation for the chemical additives, and while there is some information on the toxic properties for some chemicals, that information is lacking for others. The chemicals being used are both manmade and natural, include simple and complex molecules, and are either inorganic or organic. While some of these chemicals are well known and used for other purposes (e.g. hydrochloric acid, and ethylene glycol), as technology has advanced, chemicals have been developed that are used exclusively for hydraulic fracturing. As a result, there are filings for new chemicals and the number of chemicals is increasing. The expert also mentioned that there is a trend towards using less hazardous chemicals.

The Panel heard from an expert on toxicology who explained that all chemicals are toxic and have the potential to produce harm. However, the dose (quantity, frequency, and duration) is important to quantify. Thus, it is important to consider the exposure opportunity for a health impact to be realized. Toxicologists can use models to estimate potential health impacts, but the uncertainties in using models can lead to mis-estimation of the impacts. To truly understand the potential health impacts of these chemicals, the expert on toxicology explained that there is a need for specific place and time information (what chemicals are being used where, and when, and for how long, and in what nature) – this is a moving target.

It was also explained that the health effects differ depending on whether the exposure is acute (minutes to days) or chronic (days to a lifetime). People also vary in their susceptibility or sensitivity to chemical insult; young children and the elderly are generally more susceptible. However, there is a variety of health determinants, including behaviour (lifestyle choices), genetics, health care, environment and social, which need to be considered in any epidemiological study. In remote areas, where population density is low, the expert noted that it is difficult to obtain data on health determinants.

The expert explained that people speak to the chemicals used in hydraulic fracturing and label them as carcinogens and neurotoxins. He stated, "*this is fair, but such categories ignore exposure level.*" He noted, "*reference to exposure is not given in any reports, and 'associations' [i.e. connections between hydraulic fracturing fluids and health impacts] are unclear, weak, and have little relation to exposure.*" The expert summarized, "*To date, there have been few studies on health impacts related to hydraulic fracturing. What studies have been published have been observational in nature; for example, they try to show associations between proximity to wells* *and utilization of hospitals, material or health outcomes. There is no quantification of exposure, but rather indirect measures, such as well density, etc. When these studies are reviewed by experts, weaknesses in the experimental design or in the reporting come to light. Moreover, the samples sizes are small, symptoms are self-reported, and sometimes are associated with legal cases where it is possible to have bias. Ultimately, no causality has been identified in these studies*."

Given the limitations of previous studies, the expert provided some thoughts on what types of studies would be most useful. Two broad categories of studies were explained: 1) epidemiological studies, and 2) health risk assessments. The challenge for (1) in NEBC is that the area where hydraulic fracturing is occurring has sparse population, with diverse health determinants, and so sample size is insufficient. It could be possible to carry out such a study with other jurisdictions, but because of differences in geology and operations, it would be extremely difficult if not impossible to compare results. The challenges for (2) are numerous. Several things need to be identified: i) the specific chemicals, ii) the receptors (people, livestock, fish), iii) the exposure pathways (drinking, bathing) – these could include airborne toxins, iv) the assessment of toxicity (for mixtures of chemicals), and v) the dose and exposure – but there are poor baseline data available. The expert suggested that other experts in epidemiology would likely rule out epidemiological studies because they would take 20-30 years to complete. So, health risk assessments are probably the best option despite the significant challenges with data collection.

The public health expert from the BC Ministry of Health described the results of a study to examine human health risks in NEBC. The key findings of the study are discussed below. In addition, an ENGO that presented to the Panel summarized the key findings from their report (Pembina 2018), which are also summarized below.

7.1.3. Other Evidence Considered

The Ministry of Health's "Human Health Risk Assessment" study was carried out in three phases. Phase 1 (initiated in 2012) was conducted by the Fraser Basin Council and involved broad consultation with community members with the aim of seeking input on potential human health risks related to oil and gas development in NEBC[76]. The identified areas were meant to inform the scope of the subsequent phase, i.e. human health risk assessment. One of the most common concerns raised was hydraulic fracturing and the perception that this activity could lead to seismic activity, water quality issues, or the potential to trigger sour gas releases. In addition to water quality, a broader issue of concern for human health, safety, and well-being is access to sufficient quantities of fresh water.

[76] BC Human Health Risk Assessment – Phase 1: https://www.health.gov.bc.ca/library/publications/year/2012/Identifying-health-concerns-HHRA-Phase1-Compendium.pdf

Phase 2 of the study was carried out by Intrinsik Environmental Sciences (2014). The scope of oil and gas activities considered in the review included potential emissions to air and water from operational sites, historical sites, and transportation of both products and waste. The major objectives included: i) a screening level risk assessment (SLRA) of scenarios; ii) a quantitative risk assessment for chemicals of concern (scoped to scenarios where "quantitative" assessment could be conducted), and iii) recommendations. A review of the existing statutory, regulatory and policy framework that contributes to the projection of health of individuals living in proximity to oil and gas development and/or activities in NEBC was also carried out.

The study examined risk related to six pathways and carried out a SLRA for different scenarios involving each. Based on the findings of the SLRA, two scenarios emerged as the top priorities for further evaluation in the detailed human health risk assessment: (1) ongoing emissions associated with gas processing plants; and, (2) ongoing emissions from production facilities. Both are outside the scope of this review. In addition, the SLRA described a number of other scenarios related to the scope of this review that could, in theory, pose a risk to human health. However, the SLRA concluded that because of the site-specific nature of these scenarios, the "*human health risk associated with water-related scenarios, including those associated with hydraulic fracturing, can be assessed only on a case-by-case basis, using site-specific environmental data to characterize the source, pathways, and exposure*." Numerous gaps were identified including a lack of water quantity and quality data with which to assess the likelihood or scale of impacts; uncertainty in the actual chemicals of concern as these may vary geographically and between operations / companies; uncertainty in the completeness of available data, particularly for older sites; uncertainty in the hydrology (groundwater flow directions and interactions between surface water and groundwater); and limited aquifer mapping and assessment of the vulnerability of aquifers. The report also included several recommendations specifically aimed at the BCOGC.

Phase 3 of this study was communication. The Ministry of Health expert admitted that this phase of the study did not meet the needs of the public because it did not provide a sufficient level of detail on site-specific impacts (e.g. like flaring right next to a house and the potential impacts). This is unfortunate, because the Ministry spent more on this study than on any other previous study.

Since this study was completed, a regional scale shallow groundwater vulnerability map was produced for the Peace Region (Holding and Allen 2015). In addition, risk to water security maps were produced that show vulnerability of surface water and groundwater quality and quantity (four maps). The maps combine the intrinsic susceptibility of each water system with potential hazards associated with oil and gas activities (Holding et al. 2018). Due to a lack of statistical data on the specific hazards, the maps only display potential risk as a vulnerability.

The Pembina Institute conducted a literature review of the potential impacts of hydraulic fracturing, with somewhat of a focus on risks to water and public health (Pembina 2018). The report did not discuss any studies in depth; therefore, the Panel reviewed some of the cited works. The authors of the report noted that most of the research has been conducted since 2013, mostly in the U.S., and highlighted that data for BC are lacking. The authors acknowledged the Ministry of Health study (above), but noted that the literature review associated with the risk assessment occurred before the recent surge in relevant scientific studies on this topic and, as a result, included minimal recent research on the public health impacts related to unconventional natural gas development (UNGD) in North America. The authors argued that BC has a similar regulatory environment to other jurisdictions, and the risks are largely associated with the management of produced water and well construction practices, which are common across North America. Thus, while the geology and hydrology of BC is distinctly different than elsewhere, the findings of these studies were considered relevant to BC.

Specific to human health, two reports were cited, which are described here. The first by Caron-Beaudoin et al. (2017) reported increased levels of a benzene biomarker (t,t-MA) in the urine of pregnant women in NEBC with a median concentration 3.5 times higher than other Canadians. The median S-PMA level was similar to that of the general public [note the Panel is unfamiliar with these biomarkers]. Urinary metabolite levels were slightly higher in self-identifying Indigenous women, but this difference was only statistically significant for S-PMA (the median t,t-MA level in Indigenous women was higher than in non-Indigenous women, although this difference was not statistically significant ($p = 0.07$)). The authors state, "*benzene exposure can occur from active and passive smoking, filling gas tanks and automobile driving…. Whether the high urinary t,t-MA levels measured in this study are related to hydraulic fracking remains unknown*." The study concludes that given the small sample size and limitations of t,t-MA measurements (e.g. non-specificity), more extensive monitoring is warranted.

The second study by Kassotis et al. (2014) sampled waters from densely drilled and control areas in Colorado and concluded that unconventional oil and gas activity is potentially associated with endocrine disrupting chemicals (EDCs). The authors suggest that there are over 100 known or suspected EDCs commonly used in hydraulic fracturing. Kassotis et al. (2016) assessed endocrine disrupting activity in surface water at a West Virginia injection well disposal site where the chemical analyses indicated release of wastewater had occurred. Water samples were collected from a background site in the area and upstream, on, and downstream of the disposal facility. The authors conclude that high levels of EDC activities in surface water extracts were associated with a wastewater injection disposal facility.

The toxicology expert mentioned a specific study by Werner et al. (2015). These authors conclude that many studies present information on these [environmental health] concerns, yet the strength of epidemiological evidence remains tenuous. Of the 109 environmental health studies conducted between January 1995 and March 2014 that ranked high in relevance, only seven were considered highly relevant based on strength of evidence, with much of the health impacts inferred rather than evidenced. Of the highly relevant studies, 40 papers in the peer-reviewed literature and 26 in grey literature focused on water and soil. A further 18 peer-reviewed (and 12 grey literature) focused on societal impact (symptomatology and risk perception). Other papers (63 peer-reviewed and 59 grey literature) focused on air quality, noise and light, traffic, and government and/or regulation. Additionally, the majority of studies focussed on short-term, rather than long-term, health impacts, which is expected considering the timeframe of UNGD; therefore, very few studies examined health outcomes with longer latencies such as cancer or developmental outcomes. The authors conclude that the studies generally lack methodological rigour. Importantly, however, there is also no evidence to rule out such health impacts. The authors of the papers examined expressed concerns based on credible evidence of detrimental environmental impact and strongly suggest that the lack of evidence of health impact does not dismiss claims of health impact. The authors also conclude by noting that the hydrogeology and environmental settings of different shale gas regions vary, and that it will be important to conduct similar research in other regions to determine if environmental health hazards and impacts are similar, or if there are additional environmental health concerns that should be considered.

7.1.4. Key Findings

As summarized by Werner et al. (2014), "*while the current evidence in the scientific research reporting leaves questions unanswered about the actual environmental health impacts, public health concerns remain intense. This is a clear gap in the scientific knowledge that requires urgent attention*." Notwithstanding, there are clear challenges for conducting epidemiological studies in NEBC due to the sparse population and diverse health determinants. Human health risk assessments also carry considerable uncertainty given the large number of parameters for which there is little information. The toxicologist who presented to the Panel summarized by explaining that this is a cocktail problem (we don't understand mechanisms) and we are "*profoundly ignorant about what is going on*."

Public health broadly encompasses all aspect of human health, not solely epidemiology. For many residents, fear of uncertainty surrounding UNGD can also lead to stress, worry, and anxiety. Perception of health risk posed by UNGD is therefore an important issue to consider. For First Nations, shale gas development (in addition to other activities) compromises their ability for peaceful enjoyment. As such, public health concerns are largely centered around the cumulative effects of hydraulic fracturing (e.g. concerns over the vast volumes of water used for fracking, the storage and transport of contaminated fluids at surface and the potential for spills and leaks, the disposal of contaminated fluid underground, etc.).

At present, the Panel is not aware of any health-related studies being conducted in NEBC. In the view of the BC Ministry of Health expert who presented to the Panel, current water quality sampling (i.e. the Private Wells Study) is not being carried out to screen for potential impacts of hydraulic fracturing fluids and wastewater on drinking water. The goal of that study is to sample groundwater to understand the background geochemistry of the groundwater to inform on aquifer mapping.

7.1.5. Recommendations

Insufficient evidence was presented to the Panel to assess the potential risks to human health that may be associated with hydraulic fracturing in NEBC. This is not to suggest that the risks to human health from hydraulic fracturing are not important or potentially significant, but rather that existing studies (mostly in the U.S.) have been inconclusive due to lack of quantification of exposure, small sample sizes, weak associations, among other shortcomings from a scientific perspective.

It is the opinion of the toxicology expert and the Panel that epidemiological studies are not recommended for NEBC. A broad health risk assessment could be conducted; however, there are so many unknowns in so many aspects that the results of such a study (or studies) would likely not be useful. Perhaps a limited scope health risk assessment could be conducted using the top 10 chemicals (including for example borates, which are very toxic; benzene, for which there is no safe level).

It is the view of the Panel that part of the solution is to control exposure (minimize, prevent), which would then minimize the risk to the public. There is a need for industry and government to appreciate and openly acknowledge the various risks associated with hydraulic fracturing. Spills have occurred that have impacted groundwater and surface water, so it is critical that industry enhance awareness of spill response and mitigation, and build a culture of safe operations (avoid all spills, report all spills, and promptly mitigate all spills). This culture was communicated by some of the larger operators who presented to the Panel. Perhaps a lower threshold for reporting spills should be considered by government to bring closer attention to the importance of spills. Reducing exposure is key to reducing risk.

A number of initiatives have been taken by regulatory agencies to ease concerns surrounding hydraulic fracturing fluids; for example, FracFocus. However, FracFocus is not 100% disclosure. CAPP encourages the disclosure of the trade name of each additive, the general purpose of each additive in the mixture, the name and chemical abstract number of each chemical ingredient listed on the MSDS, and the concentration of each ingredient, but this is only recommended best practice. Government should consider refining the fracture fluid disclosure process to aid authorities and health professionals in accessing information about fluid ingredients, without compromising confidential business information. Moreover, discrete chemicals should be listed on FracFocus given the potential for chemical reactions. Industry should be encouraged to use the least hazardous chemicals.

To build trust from the public, baseline, pre-drilling groundwater testing requirements should be implemented in regulation. Currently, CAPP recommends best practices and some companies are exceeding these. However, currently, there is insufficient testing at the site scale and no understanding of the time factor.

7.2. Impacts to the Environment

7.2.1. Concerns Raised

"*Wherever they [Indigenous people] went in the bush, the ground was springy and they could carry a pail and dip it into water and drink tea made with that water – that is no longer the case – so there is something out of balance in regard to water.*"

Concerns about potential impacts to the environment were clearly voiced by representatives who spoke on behalf of Treaty 8 First Nations, environmental consultants, academics, and ENGOs. Many of these concerns were discussed in detail in the previous sections. In this section, the Panel has attempted to take a step back and consider the broader impacts to the environment, specifically in relation to ecological impacts. In support of this discussion, the Panel sought input from an expert on water quality guidelines and water quality objectives. To the Panel's knowledge there are no water quantity guidelines or objectives, apart from general guidelines on environmental flow needs (EFNs).

7.2.2. Summary of Expert Evidence Presented

During the Panel Proceedings, representatives who spoke on behalf of Treaty 8 First Nations expressed their views regarding impacts to the environment. They explained that 50 to 60% of wetland areas in NEBC exist as narrow niches with unique conditions that support a particular ecological system. They expressed concern that there are so many well pads / treatment facilities that the entire ecological integrity of the area has been "*messed up to the point that one cannot trust that conditions necessary for cultural use still exist*." If the ecology is disrupted, then spiritual connection is lost. So, if water is collected upslope, mostly from wetlands, and is diverted (dammed), it changes the natural system to such a degree that that entire ecology is disrupted. This changes the spiritual aspect as well. Often a traditional knower cannot "tell" people about what the impact is, because it goes much deeper than water as a material. It is spiritual as well. Representatives who spoke on behalf of Treaty 8 First Nations talked about berries (picking out of certain patches – secret patches); water is an integral part of berry growing, but if the water disappears, then there are no more berries. In the past 100 years, First Nations have adapted their diets because traditional foods are not available (berries are just one example).

Small and large freshwater storage ponds dot the landscape. First Nations believe that this stored fresh water is changing wildlife migratory paths. Animals are going to these ponds instead of natural water sources. The BCOGC has responded to concerns about the water quality by saying that they test (or companies test) water quality, but no details are given. Animals (moose and bison) are also attracted to sumps at well sites. In some cases, these areas are fenced, but not completely (e.g. there was no gate at one site). Photos were shared with the Panel by representatives who spoke on behalf of Treaty 8 First Nations showing a dead moose tangled in loose fencing around a sump. Companies are apparently only required to fence near populated areas. Industry is still cleaning up areas that were contaminated in the 1950s. Animals find salt licks and then they are on the move. Whether the animals are coming from a contaminated area is not known, meaning their meat cannot be trusted.

Minimum volumes and flows are needed to support ecological health. The WSA defines "environmental flow needs", in relation to a stream, as the volume and timing of water flow required for the proper functioning of the aquatic ecosystem of the stream (WSA, Section 1). Section 15 of the WSA requires that a decision maker must consider the EFNs of a stream or an aquifer that is reasonably likely to be hydraulically connected when making a decision on an application, unless a specified decision is exempt under the Water Sustainability Regulation. Section 14 of the WSA provides the comptroller and the water manager with powers respecting an application for a water licence. These include but are not limited to the following:

- Refuse an application;
- Require additional plans or other information; or
- Issue one or more conditional or final licences on the terms the comptroller or the water manager considers proper.

Notwithstanding the requirement to maintain environmental flow, people have been noticing that flows in the Kiskatinaw River have been falling. There is concern that if the benthic communities are not healthy then there will be no fish.

When assessing EFNs, it is important to consider the life cycle and different aquatic species. However, very few studies have been conducted to support an understanding of EFN thresholds. Notable exceptions are the Petitot watershed project (described in Section 4.2.2) and the Horn River Basin (HRB) study, which included ecological assessments. A CABIN approach was used to assess the aquatic health between various watersheds in the HRB using test sites and reference sites. Reference sites were established in areas minimally impacted by human activities and test sites were established in areas downstream or adjacent to human activities. The final report by Kerr Wood Liedel (2016) indicated that the Environment Canada reference condition bioassessment model for the HRB was expected to be completed in 2016. This model would allow an evaluation of the test sites to be compared with a reference condition in efforts to determine the test sites level of divergence (i.e. how similar or different the test site is from the reference sites). The CABIN program terminology specifies that test sites will each fall under one of the following categories compared with the CABIN model reference sites: similar, mildly divergent, divergent, or highly divergent. It was recommended that the test sites be re-evaluated against the reference condition for the HRB when the Environment Canada Bioassessment Model becomes available to determine which category of the test sites fall into. After that, if the test sites are divergent, the next step would be to characterize that difference and assess the biological significance of potential divergence from pristine conditions. The Panel does not know the status of this bioassessment model and whether the recommended follow-up evaluation has been completed.

There is an interest on the part of First Nations to work with government to determine what quantity of water is needed to sustain the flora and fauna to meet a certain quality of life. Specifically, there is a willingness to conduct an aboriginal baseflow modelling process with consultants that brings together traditional knowledge to develop a better approach. This type of work has been done in Alberta, and it was found that there is no longer enough water in 80% of areas to support their [Indigenous people's] way of life.

Concern about water quality impacts on environmental health was raised. Therefore, the Panel sought input from a government expert on water quality guidelines (WQGs) and water quality objectives (WQOs). Ambient WQGs are developed to promote healthy ecosystems and protect human health. Water quality guidelines are science-based levels of physical, biological, and chemical parameters for the protection of water uses such as aquatic life, wildlife, agriculture, drinking water, and recreation. Available toxicology data for the most sensitive species at the most sensitive stage of life (from published laboratory studies) are used to derive WQGs. BC works closely with the Canadian Council of Ministers of the Environment (CCME) in developing guidelines, and guidelines are set to "no impact" levels. WQGs have province-wide application and include substances of concern. At present, there are 43 approved WQGs and working WQGs across BC. In relation to hydraulic fracturing fluids, major substances of concern include extremely high salinity (~250,000-280,000 ppm), metals, organics (e.g. polycyclic aromatic hydrocarbons or PAHs), and NORM. Guidelines need to be considered, but they can be exceeded. Moreover, there are no guidelines for mixtures of different chemicals, such as with hydraulic fracturing fluids, so for permitting, people must consider the individual chemicals only. As discussed in Section 4.6, the expert noted that there has been a request by NEBC offices about guidelines for NORM. However, no guidelines were found internationally. The expert briefly described several studies to the Panel. For example, Elliot et al. (2017) reviewed 4337 papers as of July 2018 in the shale gas environmental research database managed by the New Brunswick Department of Environment; however, the expert indicated that most papers were missing information on toxicology.

In contrast, WQOs are policy guidelines that are defined on a site-specific basis (i.e. they are specific to individual waterbodies). Although sometimes the WQO simply adopts the WQG. WQOs are a means to assess cumulative impacts. At present, there are 65 WQOs for 150 waterbodies across BC. The Panel notes that there are no water quality objectives for groundwater in NEBC.

7.2.3. Other Evidence Considered

The Panel was referred to one study on the ecological risk of an accidental release of flowback water (Ghandi et al. 2017). Using a conceptual ecological risk framework, the authors conducted a case study for accidental release of hydraulic fracturing flowback water in the Montney unconventional play trend in NEBC. The flowback water quality data for 212 wells (retrieved from Accumap), including the concentrations of various salt ions, metal ions, and hydrogen sulfide, was collected for the assessment. The exposure route assessed in this study is runoff of the flowback water from land into the surface water body from the source of spill. Scenario analysis was done for monthly creek discharge at Flatbead Creek, and a relationship between risk quotient and the ratio of spill volume to the creek discharge was derived. The risk quotient is defined as the sum of the ratio of exposure concentration to effects concentration for each contaminant. If the risk quotient is greater than one, there is a possible adverse effect to the ecology. The results of the case study analysis determined the risk quotient to be 0.16 (<1), proving no significant risk to the aquatic ecosystem with 90% confidence. However, the authors point to several limitations: 1) The analysis assumes additive risk for the contaminant and does not take into consideration synergistic or antagonistic effects of the combined mixture; 2) It does not consider all the behavioural aspects of a metals and salts like speciation, precipitation, colloid matter, interaction with organic matter, bioaccumulation, bioavailability, and sediment deposition; 3) Salt ions and their interactions with the soil and background water are not assessed; 4) The interaction and transport of the contaminants with groundwater is not analysed; and 5) The risk assessment for soil ecology and organic contaminants is not included. In summary, the authors state that the overall uncertainty and scenario analysis concludes that the risk to the ecology cannot be completely overlooked.

7.2.4. Key Findings

Overall, very few studies have been carried out in NEBC that were specifically designed to assess environmental impacts of oil and gas development. Notable exceptions include the Petitot watershed study, the HRB study, and the ecological risk study by Ghandi et al. (2017).

Assessment of EFNs is challenging, as discussed in Section 3.3, and the Panel reiterates that hydrogeological consultants in the province have been having difficulty carrying out such assessments, particularly in relation to assessing EFNs as described in Provincial Guidance WSS 2016-01[77].

The Provincial EFN Policy includes a section on adaptive management, stating, "*The field of environmental flow needs is an emerging science with large uncertainties in flow alteration and ecosystem response. Over time, an adaptive management approach with monitoring and site-specific detailed studies will build our body of knowledge and potentially lead to refinements in*

[77] Provincial Guidance WSS 2016-01: https://a100.gov.bc.ca/pub/acat/public/viewReport.do?reportId=50832

the policy. Adaptive management is particularly important with climate change projections for shifts in streamflow hydrographs and increasing variability." The Panel notes, however, that adaptive management plans should be carefully designed. Currently, in Canada, adaptive management is being used as a way to avoid making decisions. Olszynski (2017) calls it a "failed experiment," and countless other scholars agree that it has "failed more often than it has not" (Allen and Gunderson 2011). Benson and Schultz (2015; p. 39) state that adaptive management is "*thrown like a blanket on top of existing authorizations and requirements with little attention to how practitioners balance this new mandate in relation to other legal and institutional requirements*."

7.2.5. Recommendations

The information needs survey by Lapp et al. (2015) identified the development and testing of methods/models for defining environmental flow needs as a high priority. The Panel concurs with this recommendation. There are some good hydrometric data in NEBC that may allow for EFNs to be evaluated in a way that considers the life cycle and different aquatic species. An aboriginal baseflow modelling study should be considered by government.

7.3. Risk to Safety

7.3.1. Concerns Raised

The probability of an earthquake is defined by the seismic susceptibility (Section 5.2). Seismic hazard (Section 5.3) defines the probability the ground shaking from an earthquake may cause harm and seismic risk defines the probability that the ground shaking will have harmful consequences. Assessing the seismic susceptibility in response to fluid-injection requires knowledge of which geological and operational parameters control inducing anomalous seismicity. A location model for seismic susceptibility, as well as the recurrence rate from the magnitude-frequency distribution, and a ground motion prediction equation describing the relationship between ground shaking intensity and hypocentral distance for different magnitude events are needed to assess seismic hazard. Seismic risk is assessed by including tolerance and exposure to seismic hazard assessments.

The potential seismic risks of concern include the nuisance and mental health issues associated with felt induced seismicity, damage to critical infrastructure, and wellbore integrity issues resulting in a pathway for the upward transport of deep fracturing fluids to near-surface potable water sources. Concern was expressed by the induced seismicity experts interviewed by the Panel that the current coverage of accelerographs is insufficient to understand which ground motion parameters control whether an event will be felt or how the ground motions relate to damage criteria for structural and non-structural components. Some experts were also concerned that the current thresholds set by BCOGC are not sufficient to address public concern and that a damage criteria or seismic risk matrix approach should be adopted. Additionally, it was suggested that improved monitoring coverage is needed to assist operators in preventing and mitigating against frac hits, which may breach casing integrity.

7.3.2. Summary of Expert Evidence Considered

An assessment of seismic risk is not currently required by the BCOGC prior to fluid-injection operations. The CAPP Hydraulic Fracturing Operating Practice (2012), however, includes assessing the tolerance and exposure to hazard. All operators who presented to the Panel described including risk in their pre-assessments of hydraulic fracturing operations.

No substantiated claim of damage has been linked to anomalous induced seismicity (AIS) in BC. As the maximum potential magnitude for AIS due to fluid-injection in BC is unknown, whether damage may occur is also currently unknown, and public concerns persist. In particular, the damage to critical infrastructure, namely dams, and wellbore integrity were expressed concerns. The nuisance, destruction of the peaceful enjoyment of land, and possible mental health issues arising from anxiety and/or fear resulting from felt AIS are also key concerns raised to the Panel.

Felt Events

The majority of the events with $M \geq 2$ occur in the N. Montney within the Foothills thrust belt where large thrust faults are present. In the N. Montney, 436 induced earthquakes with $M \geq 2$, and 65 with $M \geq 3$, have been reported since 2008 by NRCan. In the S. Montney, within the Fort St. John Graben, which is characterized by small to moderate, strike-slip faults, 147 $M \geq 2$ induced earthquakes, eight with $M \geq 3$, have been recorded. While a greater number of anomalous earthquakes have been induced in the N. Montney compared to the S. Montney, only a few events with $M \geq 3$ have been felt in the less populated N. Montney, resulting in eight seismic complaints compared to 75 seismic complaints reported in the S. Montney for events with magnitudes as low as 1.5. The public reports of felt events consistently mention a loud bang followed by a jarring motion or short period of rumbling, rattling, or shaking. The number of felt reports has steadily increased from 9 in 2016, 22 in 2017, to 52 in 2018. The increase in reports is believed by the BCOGC to reflect a combination of increased awareness of felt events and how to report them, as well as the increased industry focus on liquids rich reservoirs, which are primarily located in the more seismogenic Lower Montney in the S. Montney, which has the highest population density.

Operators within Kiskatinaw Seismic Monitoring and Mitigation Area (KSMMA), where the bulk of the felt events occur, are required to notify residents prior to oil and gas activities. The notification must include a description of the activities and when they will happen, an explanation of what to expect if a seismic event is felt, an outline of the monitoring and mitigation plans in place, as well as contact details in case an event is felt or causes damage. The notification provides assurance that the operators are prepared and will take responsibility as well as inform residents of what to expect and what to do. Anecdotal evidence provided by many experts suggests that by improving communication with residents, the nuisance and anxiety associated with felt AIS can be significantly decreased.

The accelerograph monitoring requirement in the N. and S. Montney, implemented by BCOGC in 2016, has increased the available ground motion data and hence understanding of felt seismicity; however, the experts expressed concern that the current coverage of accelerographs is insufficient to understand which ground motion parameters control whether an event will be felt or to understand the site amplification and radiation effects on the ground shaking intensity. Concern was also expressed that the current thresholds for mitigating AIS are not sufficient to prevent public concern. It was further noted that a measure of ground motion other than Peak Ground Acceleration (PGA) and Modified Mercalli Intensity (MMI) should be used to more effectively communicate the shaking intensity to the public.

Critical Infrastructure

The possible damage to critical infrastructure, most specifically to hydro-electric dams, was expressed as a concern by several ENGO presenters and the representatives who spoke on behalf of Treaty 8 First Nations. As explained by several induced seismicity experts, the real concern is not for catastrophic damage, but minor, non-structural damage, which can result in operational disruptions and non-negligible economic losses. For example, ground motions may be sufficient to misalign the spillway gates, which may need to be opened to inspect for other damage. Concern was expressed by the experts that the current coverage of accelerographs is insufficient to understand whether ground motions from induced events may pose a risk to critical infrastructure and how the ground motions relate to damage criteria for structural and non-structural components.

Operators within 5 km of the Peace Canyon, WAC Bennett, and Site C dams, as well as the Aitken Creek Gas Storage Facility are currently required, through permit conditions, to notify the facilities 21-45 days prior to all drilling and completions activities. Disposal wells within close proximity to hydro-electric dams are also given specific approval conditions (BCOGC[78]).

The Peace Canyon, WAC Bennett, and Site C dams are also located in KSMMA. Hence, an assessment of the seismic hazard, monitoring, and mitigation plans, as well as a true traffic light protocol (discussed in Section 5.4) including a lower magnitude threshold for the suspension of operations then elsewhere in Western Canada (M3 versus M4) are required. Some confusion was identified during the Panel presentations regarding the requirements around the hydro-electric dams, with some experts incorrectly believing no fluid-injection activities are permitted within 5 km. There was also concern expressed that a 5 km radius exclusion zone for fluid-injection operation might be insufficient to limit ground motions that may be deleterious to dams. Additionally, it was suggested that other critical infrastructure should also be notified

[78] BCOGC Order 08-02-008 (Amendment #2): https://bcogc.ca/node/14885/download

prior to fluid-injection operations. Atkinson (2017) suggests that an effective strategy for preventing damage to critical infrastructure should include a 5 km exclusion zone and an increased monitoring plan to track the rate of events with M≥2 within 25 km.

Wellbore Integrity

The potential contamination of potable groundwater resulting from casing damage and loss of wellbore integrity due to AIS is a concern expressed by many of the environmental groups who presented to the Panel. Currently, operators are required to report instances of integrity loss that impact well performance, which includes damage to the vertical section of wells (BCOGC DPR[9]). Operators must also assess the risk of frac hits to offset wells located within a 3 km radius, including wellbore casing burst and collapse strengths, and must report all inter-wellbore communication. To date, no loss of integrity of the vertical section of wells has been observed as a result of fluid-injection. Damage to the lateral (i.e. horizontal) section of wellbores, which are generally believed to be too deep for fluid migration to potable water sources, has been observed (see Section 4.3). However, as the casing damage is only identified when drilling out plugs when a plug and perf completion style is used (currently 68% of completions in the Montney are plug and perf in contrast to a low of 24% in 2016), and most instances do not require reporting to the BCOGC, it is unknown how often AIS results in casing damage. Additionally, as groundwater quality is often not monitored, it is unknown whether casing damage poses a risk to groundwater quality. The experts suggested that increased monitoring and reporting is needed to quantify the potential risk from loss of wellbore integrity.

Risk-based Mitigation

The experts expressed concern to the Panel that the seismic risk from AIS is not adequately represented by the current magnitude thresholds. While the experts agreed that ground motion information should be incorporated into TLPs, some suggested that a more risk-based approach should be adopted using existing standards from other industries or risk tolerance matrices. It was noted, however, that a more risk-based approach requires greater accelerograph coverage to understand which ground motion parameters control whether an event will be felt or how the ground motions relate to damage criteria for structural and non-structural components. It was further noted by the experts that existing standards or risk matrices would more effectively communicate the risk from AIS to the public.

In general, the peak ground acceleration of an earthquake tends to correlate with felt effects, while the damage potential is more closely correlated with the peak ground velocity. In addition to the ground-motion amplitudes, the duration and frequency of strong ground motions are important factors which may impact the damage potential. Therefore, several experts suggested that an alternative criteria, such as leveraging existing tolerance thresholds for blasting, traffic, pile driving, etc. (Figure 35) should be used to better define the risk from AIS. Fragility curves based on non-structural damage may also provide a promising alternative for quantifying seismic risk (Megalooikonomou et al. 2018). The damage criteria could be incorporated into a performance-driven monitoring system as suggested by some researchers (e.g. Parolai et al. 2015, 2017; Bindi et al. 2016; Megalooikonomou et al. 2018).

Additionally, it was proposed by several experts that a matrix approach, such as proposed by Walters et al. (2015), may be more effective than linear thresholds. Walters et al. (2015) developed a workflow, which integrates tolerance and exposure into a TLP, to produce different risk tolerance matrices for each level of exposure (Figure 36).

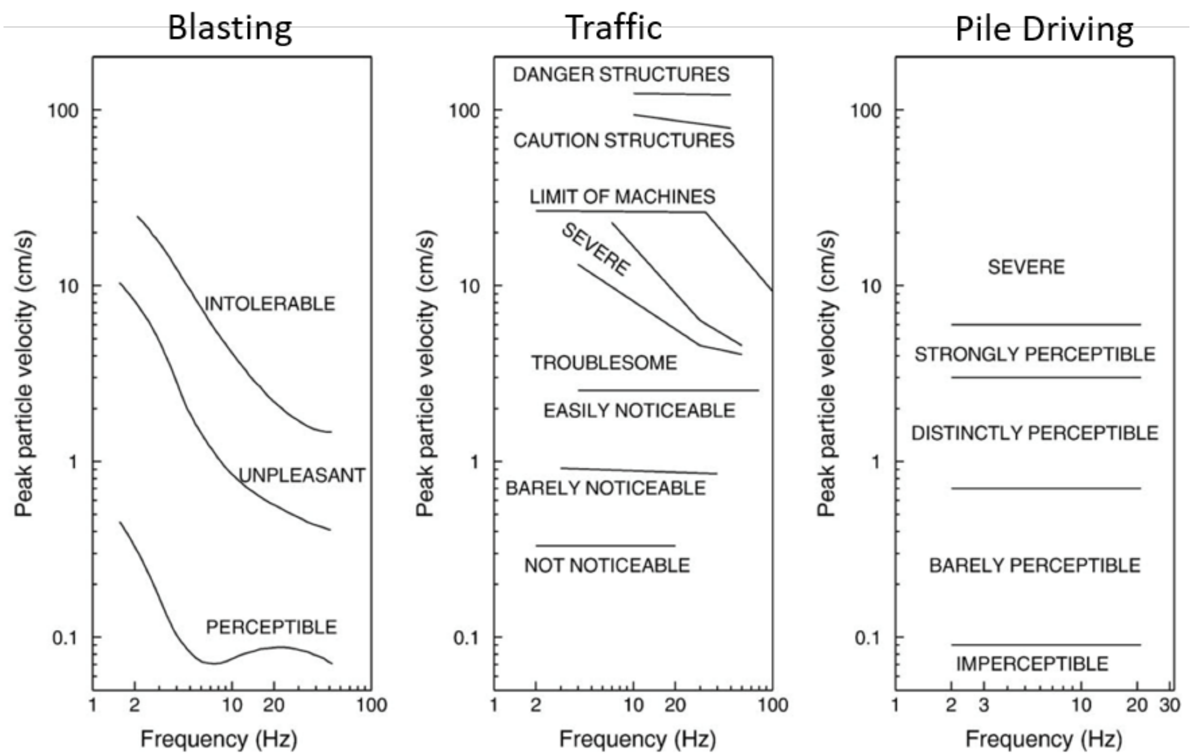

Figure 35. Examples of existing thresholds for tolerable ground motions, defined by peak ground velocity (i.e. peak particle velocity) and dominant frequency. Modified from Bommer et al. 2006.

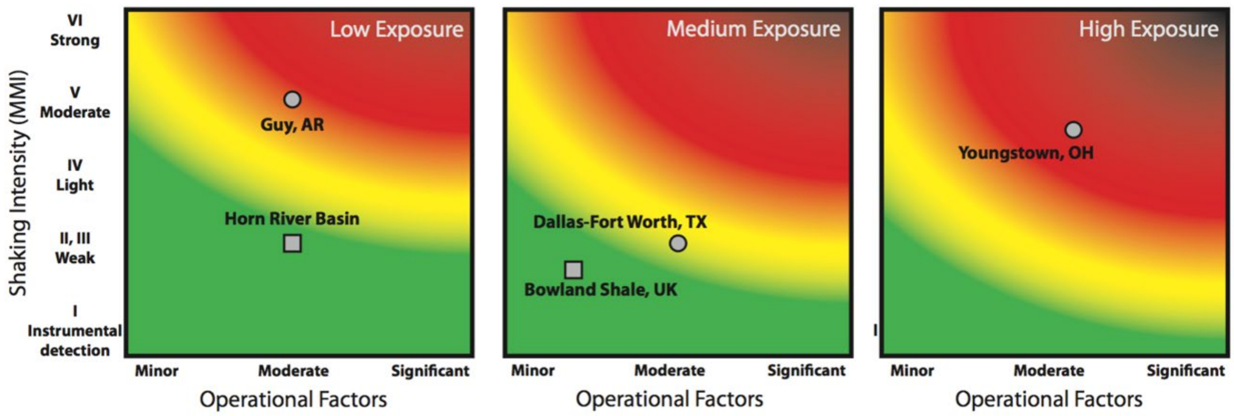

Figure 36. Risk tolerance matrices calculated by Walters et al. (2015).

7.3.3. Key Findings

The risks associated with induced seismicity in response to fluid-injection activities in BC that were expressed to the Panel include the nuisance, destruction of the peaceful enjoyment of land, and possible mental health issues resulting from felt events, damage to critical infrastructures, and loss of wellbore integrity. While no damage has been associated with AIS to date in BC, the maximum potential magnitude for AIS is unknown; therefore, whether damage may occur is also currently unknown. Operators within KSMMA, where the bulk of the felt events occur, are currently required by the BCOGC to notify residents prior to oil and gas activities. Anecdotal evidence was presented that the enhanced communication requirements have significantly decreased the nuisance and anxiety associated with felt AIS by stakeholders. Operators within 5 km of the Peace Canyon, WAC Bennett, and Site C dams, as well as the Aitken Creek Gas Storage Facility are also required to notify the facilities of hydraulic fracturing. However, some concern was expressed that all critical infrastructures do not receive enhanced communications by BCOCG. Concern was also expressed that an exclusion zone does not exist around critical infrastructure. While the experts agree that the hazard from wellbore integrity issues is low, as casing damage has only been observed to date in the horizontal section of wells in BC and these are deep beneath potable water sources, they also noted that the true hazard is unknown due to lack of reporting and groundwater monitoring.

The experts agreed that the current magnitude thresholds do not adequately represent the risk from AIS. Some concern was also expressed that the current thresholds are not sufficient to prevent public concern from felt events. Existing standards from mature industries (e.g. blasting) or other damage criteria could be used to develop a performance-driven monitoring approach or a seismic risk matrix approach could be adopted to mitigate seismic risk from AIS. The experts, however, noted that greater accelerograph coverage is needed to understand which ground parameters or damage criteria provide the best measure of whether an event will be felt and the potential damage to structural and non-structural components. It was also noted that a risk-based approach would provide a more effective measure of the seismic risk from AIS for the public.

7.3.4. Recommendations

Enhanced communication with residents ordered by BCOGC for operators in KSMMA should be expanded to include all fluid-injection activities with non-negligible seismic hazard in NEBC. The enhanced communications should also be expanded to include notification to operators of critical infrastructure in addition to residents, which first requires an assessment of which infrastructure should be classified as critical. Further investigation and discussion is needed to decide whether the current permit conditions requiring notification within 5 km of hydro-electric dams is sufficient to prevent damage or if an exclusion zone and further protocols are needed.

Operators should be encouraged to report all wellbore integrity issues and a comprehensive study of wellbore integrity should be completed to understand whether it poses a risk.

It is recommended that a 2nd workshop on the traffic light protocol (TLP) be organized to discuss whether the current thresholds are sufficient to address public concerns for felt events or if a more risk-based approach should be adopted. The different approaches should be evaluated based on the effectiveness for monitoring and measuring the seismic risk and communicating the data to the public.

Better data sharing, increasing research capacity, and expanding monitoring (discussed in Section 5.5) are needed to better understand whether ground motions will be felt or pose a risk to critical infrastructure or wellbore integrity.

7.4. Orphan Wells

7.4.1. Concerns Raised

Concerns were raised by ENGOs regarding future liabilities and tax payer risks involving “orphan wells”, a term used to describe oil and gas wells that were operated by now defunct companies that no longer can pay to plug the wells and properly restore the site. Orphan wells were expressed by ENGO experts presenting to the Panel to be a growing concern, as low energy prices force marginal operators out of business. Although many of BC’s orphan wells involve older conventional wells, ENGO experts argued that similar concerns should be extended to unconventional wells as a potential future source of orphan wells.

7.4.2. Summary of Expert Evidence Presented

BCOGC indicated that as of November 2018, there were 326 orphan well sites in BC[79]. As previously noted, BCOGC data show this to be a significant increase from the 45 orphan wells in the inventory in 2016. In discussing these numbers with the Panel, BCOGC indicated that the growing number of orphan wells primarily involves conventional wells and not unconventional wells. Unconventional wells were reported as not being seen as a significant risk driver at present. Of the 307 orphan wells in the inventory in 2017, only seven were unconventional wells. In terms of liability, it was noted that of the more than 7,100 inactive wells in BC, fewer than 1,200 are unconventional. Many of these wells are not at their end of life, but rather are awaiting infrastructure, transportation capacity, and improvements in gas prices. BCOGC stated that similar to other jurisdictions, industry restoration rates are not keeping pace with development. This increases the risk of insolvencies (leading to orphan wells), and indicates that the increase in orphan wells seen in 2017 was due to low gas prices and the bankruptcy of two smaller operators. BCOGC experts also pointed to the Redwater Court Decision in Alberta, which says that creditors take priority when an oil and gas company goes bankrupt, allowing them to renounce assets they receive that they deem to be uneconomical. BCOGC stated that the repercussions of this decision is that it is left to orphan well funds to assume the obligations for restoring these sites. They also noted that the decision is in appeal.

A representative who spoke on behalf of Treaty 8 First Nations described the situation of legacy wells as a "*time bomb*" (i.e. that the scope of leaking legacy wells is not fully known and it can take many years before leaks are observed). This representative pointed to BCOGC data for the Penalty Ranch Study Area showing 15 leaking wells with only four having been remediated. Pointing to the high cost of remediation, citing a maximum of $420K in provided data, it was noted that such sites represent both a long-term (>100 years) environmental and financial risk. It was questioned by the representative whether companies are placing adequate bonds to cover anticipated costs of maintaining well integrity and whether BCOGC has capacity to catch all non-compliance.

BCOGC presented to the Panel on how the Orphan Site Reclamation Fund (OSRF) operates. The OSFR is an industry-funded program meant to protect taxpayers from paying for restoration liability. First, however, it is preceded by the Liability Management Rating (LMR) program that requires securities to be paid by the operators where the liabilities of the site exceed the value of the assets. This is meant to ensure that the operators carry the financial risk of their assets, and to reduce exposure to the OSRF. BCOGC noted that the LMR review is conducted monthly and security deposits adjusted accordingly. On top of these securities, industry then pays a levy placed on oil and gas production into the OSRF. Thus, the OSRF is meant to cover the exposure for older wells, before securities were required, and those where the securities do not cover the full liability of restoration and the operator is no longer solvent to cover the extra costs.

[79] BCOGC: https://www.bcogc.ca/whats-new/media/commission-addresses-questions-related-orphan-sites

Once designated an orphan site, BCOGC may use the OSRF to decommission and restore the site to obtain a CoR. It was reported by BCOGC that 17 orphan well sites have been issued a CoR to date. The average cost for treating an orphan well is $300-400K per well.

7.4.3. Key Findings

BCOGC lists the current cumulative orphan inventory to be approximately 326 wells[80], a sizeable increase from the 45 reported for 2015/16. The spending on orphan wells from the Orphan Site Reclamation Fund (OSRF) in 2017/18 was $5.7 million compared to an average of just over $1 million per year over the three previous years.

It was found that tools are in place to mitigate the risk of orphan wells (LMR, OSRF), but these rely on identifying operations with elevated risk and increased enforcement. BCOGC discussed with the Panel government plans for an amendment to OGAA that has since been passed as Bill 15[81] that includes an updated orphan levy piece and a new "Dormant" classification with fixed times prescribed to restore a site. Securities to be paid by the operator will be assessed based on their financial health on a monthly basis, with BCOGC looking at using predictive analytics, and factoring in history/reputation, governance, and other information relevant to assessing risk. It was noted that BCOGC is a fee-for-service regulator, so it can only be so proactive.

It was also found that BCOGC works on an upstream model; BCOGC can take over the value of the asset relative to the liability it represents. This is adjusted on both sides of the balance sheet; cost of reclamation covered, or estimated. BCOGC looks very closely at transfer agreements from one party to another to make sure the receiver has the capacity to assume those liabilities. BCOGC can refuse transfers. The Orphan fund is a good indicator of whether bonds were sufficient or if the orphan fund was dipped into to cover extra costs.

7.4.4. Recommendations

Given that only 17 of 326 orphan well sites have received their CoR and that the cost of restoring these has averaged $300-400K per well, it would seem that the potential liabilities and costs to be drawn from the OSRF are considerable, even given the recent regulation changes to strengthen the fund. Extrapolating this to the thousands of wells that have been drilled and are still operating or are inactive and have not yet been abandoned and undergone site restoration, the risk as to whether the LMR and OSRF securities and funds will be sufficient to cover future liabilities would seem to be considerable. The Panel recommends that a transparent accounting of the potential liabilities to the OSRF, including different worse case

[80] BCOGC: https://www.bcogc.ca/whats-new/media/commission-addresses-questions-related-orphan-sites

[81] BC Bill 15 – 2018: Energy, Mines and Petroleum Resources Statutes Amendment Act: https://www.leg.bc.ca/parliamentary-business/legislation-debates-proceedings/41st-parliament/3rd-session/bills/first-reading/gov15-1

scenarios, be made public and compared to projections of how the LMR and OSRF will be able to offset these risks.

The Panel also notes that data and discussions presented regarding the OSRF focused only on concerns over orphan wells. There did not appear to be much indication by BCOGC of whether concerns should also extend to orphan dams or orphan flowback ponds in future. It is noted that the OSRF does specify that its purpose is to pay the costs of reclaiming “orphan sites” and not just wells. However, it is not clear how far the risk and potential liability for orphan dams or flowback ponds have been considered. The Panel recommends that the discussion of orphan wells be broadened to consider other major oil and gas infrastructure that can likewise result in significant liabilities and costs for reclamation and restoration.

7.5. Cumulative Effects

7.5.1. Concerns Raised

Shale gas development is one of many resource development activities in NEBC. While the Panel was asked to focus exclusively on the impacts of hydraulic fracturing, the cumulative effects of various development activities (forestry, agriculture, Site C) in NEBC could not be overlooked. Representatives who spoke on behalf of Treaty 8 First Nations, government, industry, industry groups, environmental consultants, and ENGOs included the term “cumulative effects” in their comments to the Panel. Representatives who spoke on behalf of Treaty 8 First Nations indicated that permit applications have a “cut and paste approach” to addressing cumulative effects, but because everything is done on a permit by permit basis, the cumulative effects are actually not known. One industry operator indicated that there is currently no accepted way to demonstrate cumulative effects.

This brief section reviews the Regional Strategic Environmental Assessment (RSEA) and the concept of area based management, which has been applied in NEBC. The Province’s Cumulative Effects Framework is also briefly discussed.

7.5.2. Summary of Expert Evidence Presented

In 2014, the BC Government announced a $30 million LNG Environmental Stewardship Initiative (ESI). This was followed in 2015 by the announcement of four demonstration projects: two in the Skeena Region, one in the Omenica Region, and one in NEBC (RSEA). Working agreements were signed with First Nations in 2015/16, and in 2017/18 the working agreements were renewed for a further two years. RSEA is a framework / process that includes representatives from the provincial government, seven Treaty 8 First Nations, and industry. The goals of the RSEA are to address certain environmental issues of mutual interest to BC and First Nations, and to design and implement a regional assessment of the effects of natural resource sector activities. Three objectives were defined:

1. Develop a study area for the assessment within the vicinity and overlaying the Montney Play;
2. Assess the effects of natural resource development activities on the rights of participating First Nations based on risks to certain "values";
3. Recommend management responses that avoid, minimize, mitigate, offset, or otherwise respond appropriately to the effects of natural resource development activities on the rights of participating First Nations.

Five "values" were identified: old forest, moose, water, peaceful enjoyment, and environmental livelihoods. Three projects fall under the RSEA: a broader landscape assessment; a RSEA Pilot analysis, and RSEA Interim Measures project. The overall process involves understanding the value (current state), and then projecting how the state of those values may change over the landscape for different development scenarios (future state). If LNG development is found to potentially impact values, then recommendations will be made on what needs to be done to minimize impacts going forward. For example, moving the location of a new well to a cut block because there is "no value" of the cut block for the First Nation at this time. The RSEA study is smaller than the entire Peace Region and is focused on the Montney play, extending slightly beyond its boundaries. The process is currently at the beginning of the analytical phase (defining the current state).

The Province continues to develop its Cumulative Effects Framework[82]. The phased implementation of the framework will use an adaptive management approach that can incorporate new information and refined assessment methodologies to allow for the continuous improvement of the framework. The approval of the Cumulative Effects Framework Interim Policy[83] is considered by the Province to be a significant milestone for the phased implementation of the cumulative effects framework province-wide.

In the specific context of oil and gas development, Area Based Assessment (ABA) was set up to address cumulative effects management as the provincial framework has not been fully developed and BCOGC needs to consider cumulative effects in its operational decision making and develop its own tools. Various decisions involving roads, water, seismic activity, well and facility locations, and pipeline corridors cause cumulative effects to both environmental and social values. Based on the BCOGC report Area-based Assessment: Overview[84], "*the ABA*

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[82] BC Cumulative Effects Framework: https://www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/cumulative-effects-framework

[83] BC Cumulative Effects Framework Interim Policy: https://www2.gov.bc.ca/assets/gov/environment/natural-resource-stewardship/cumulative-effects/cef-interimpolicy-oct_14_-2_2016_signed.pdf

[84] Area-based Analysis: Overview: https://www.bcogc.ca/node/12265/download

approach gathers and analyzes existing information and data on development activities in identified areas to better inform regulatory decisions. It evaluates the overall landscape to facilitate appropriate management of surface and subsurface impact… Considering effects on only a project- or sector-specific basis can allow unintended impacts to accumulate over time." ABA "*follows the adaptive management process – the Commission will monitor to measure impacts, and adjust the overall framework as required*." A guidance document Supplementary Information for Area-Based Analysis[85] outlines the considerations, development planning, practices, application procedures, and desired outcomes related to ABA. To support ABA, the BCOGC uses Environmental Information Management System (EIMS), which is an online information portal housing guidance summaries for a selection of High Priority Wildlife (HPW) species and all Wildlife Habitat Area (WHA) and Ungulate Winter Range (UWR) within NEBC. The EIMS search tool provides applicants with the ability to search by species for a summary of key habitat features, objectives, and species-specific planning and operational measures. The EIMS is updated regularly. The most recent update was made May 18, 2018. ABA reports will be updated periodically to reflect new information, including updates to relevant government policy and legislation and new development activities (Industry Bulletin 2018-05)[86].

The BCOGC website indicates timelines for implementing ABA in NEBC. The target date for hydro-riparian ecosystems, and old forest was Fall 2014, and high priority wildlife was 2015. It is assumed that both of these target dates have been met. The target date for implementing groundwater, air quality, First Nations cultural, heritage and traditional use is to be determined.

7.5.3. Key Findings

Representatives who spoke on behalf of Treaty 8 First Nations clearly expressed their support for the RSEA process. While the Panel did not review the Province's Cumulative Effects Framework in detail nor did it review the Auditor General's report on BC's Cumulative Effects Framework dated May 26, 2015, the Panel was encouraged to see that progress is being made on the development of the framework and that an interim measures policy is in place.

When asked by the Panel about the status of ABA, the BCOGC indicated that there has been limited capacity for First Nations to become involved in ABA, largely because their attention has been focused on the RSEA project.

7.5.4. Recommendations

BCOGC has the authority to make decisions on permitting (everything from well siting to water management) and uses a framework (area-based assessment) for decision making in certain areas. The overall assessment process is currently lacking in certain aspects (groundwater, air

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[85] Supplementary Information for Area-based Analysis: https://www.bcogc.ca/node/12693/download

[86] New Interim Measures Applied to Oil and Gas Applications: https://www.bcogc.ca/node/14947/download

quality, First Nations cultural, heritage, and traditional use), but could be expanded to more adequately address cumulative effects, at least in relation to oil and gas development in NEBC.

Ideally, the mapping being carried out currently under RSEA should be used to directly inform decision making related to oil and gas development. Plans to harmonize the mapping under the two frameworks (one to assess cumulative effects and one to manage cumulative effects). At present, RSEA is in a data gathering phase. Because First Nations appear to be more engaged in the RSEA process, this presents an ideal opportunity to map out a long-term plan for harmonizing ABA with RSEA.

8. Other Broad Advice

8.1. First Nations

Overall, a high level of frustration with the referral process was communicated to the Panel by representatives who spoke on behalf of Treaty 8 First Nations. The paramount concern is the lack of considering impacts from a cumulative effects perspective. The Panel heard the following comments:

> "*Right now, there is no place in Treaty 8 Territory where peaceful enjoyment is possible.*"

> "*Applications come across our desks as 'one off' requests; no one is looking at the cumulative effects of the water withdrawals, water disposal, and potential for contamination of surface water and groundwater*."

> "*For years, the Elders have had concerns about the landscape*."

> "*It is at stage that if things aren't fixed now, it will be a devastated landscape. This region is the headwater region for major river systems. But no one here is really looking at the area as a whole. Is BC having an impact more broadly than its borders?*"

The Panel heard that the Lands Office has a no-go zone(s) and that land tenure applications have been held up, with the sales dates being deferred until their [Treaty 8 First Nations] concerns are satisfied. In one area of NEBC, there has been negotiation of a less intense footprint so that First Nations can carry on their "*traditional seasonal round*."

One Treaty 8 First Nation representative provided the Panel with some statistics on proposals. Counting new production wells in the Montney alone, BCOGC data[87] show 527 new wells drilled between 2005 and 2010 (approximately 105 per year), increasing sharply to 2,056 new wells between 2010 and 2016 (approximately 340 per year). The representative speaking on behalf of Treaty 8 First Nations explained that each proposal has to be reviewed by First Nations. The time frame to respond to referrals is short, and oftentimes insufficient information is provided with the application to be able to judge the potential impacts. There is also limited capacity to handle referrals, and consultants need to be engaged to assist with evaluating applications. One consultant who works with a Treaty 8 First Nation in this capacity indicated that when they receive the referrals they are asked to refer back in a scientific way. They have to try to explain their perspective so that it can be communicated back. So, First Nations are battling with the science. Government only "accepts" scientific knowledge and is reluctant to accept traditional knowledge. The burden of proof is on the First Nation to provide scientific data/evidence. Notwithstanding, First Nations are reluctant to share their traditional knowledge, because they feel that government will "*use this information against them*." When they try to impose

[87] BC Oil and Gas Reserves and Production Report (2016): https://www.bcogc.ca/node/14704/download

conditions on a permit application, they feel that these conditions never make their way into the conditions of the permit; FNLRORD sets the requirements, but if a First Nation raises questions, the applicant says they met all FLNRORD's requirements as part of the referral process. It was also felt that currently there are insufficient resources for compliance monitoring and enforcement. As well, the bar for infractions should be set higher, because right now it is less expensive for companies to pay the fine than to deal with the problem.

A concern expressed was related to BCOGC being a single window regulator – production and protection ("*the fox guarding the hen house*"), and as such is in a conflict of interest position. The Panel notes that the BCOGC does not, in mandate or practice, have an advocacy role for the oil and gas industry, nor does it determine the Province's development objectives for oil and gas. Neither does the BCOGC have a role in granting rights to oil and gas resources or in setting or collecting royalties on oil and gas production. All of these roles fall to a separate ministry, MEMPR.

In response to broad concerns by First Nations on the referral process, the Panel asked each industry operator, the BCOGC, various ministry staff, and Geoscience BC specifically about their level of engagement with First Nations, and the degree to which First Nations are involved in projects. One industry operator hired a part time First Nations hydrology technician, and it is trying to identify First Nations technicians to undergo technical training for measuring streamflow. Another company has worked with a First Nation on a training program and has secured jobs for trainees within companies. BCOGC is also working to train First Nations through pilot studies. Most large companies feel that their level of engagement with First Nations is good, and that for the most part their relationships with First Nations are good.

Representatives who spoke on behalf of Treaty 8 First Nations indicated that the only way they can be sure rules are being followed is if they are involved in compliance monitoring. It was clear that there is mistrust. However, they indicated a willingness to support the industry if they are confident that the industry is protecting the environment. This would seem to present an opportunity. It was expressed that First Nations want to be part of the solution, and reconciliation requires that they be part of the solution. Two First Nations have formed a restoration company that grows seed stock for restoration activities. They would like to be engaged in healing the environment. First Nations would like to see this as a means to sustain their communities by restoring abandoned wells. Thus, well site restoration is both a liability, and an opportunity. The Panel strongly recommends that programs be created to facilitate the development of First Nations' companies throughout NEBC targeting the restoration of abandoned well sites that in the process leverage the value that traditional knowledge can contribute.

The Panel heard strong support by representatives who spoke on behalf of Treaty 8 First Nations for the RSEA process as well as for ABA. There is interest in a First Nations Independent Technical Review Process, which could be used for oil and gas development. There is concern that developments are complex, with inter-related processes, and this should be subject to this review process. It was suggested that BCOGC should create a regime for this, so that companies must pay for environmental consulting firms to carry out these reviews at the pre-application stage; First Nations want to be involved in the pre-application phase as well as post-approval monitoring.

8.2. Strategic Research Partnership

A repeated theme throughout many of the expert presentations to the Panel was the need for further research to address key knowledge gaps. The value of targeted research was demonstrated in the recent advances in hydraulic fracturing fluid research that has allowed for the reuse of flowback and produced water for future hydraulic fracturing treatments, significantly reducing the need for freshwater. This one advancement presents a significant step-change in reducing key concerns regarding water quantity, freshwater storage, wastewater storage, and wastewater disposal.

BC's shale gas resources represent an emerging energy source and an economic opportunity for BC. As an "unconventional" gas resource, experience with shale gas development is in its early days. It is the Panel's opinion that research is needed to support the responsible development of BC's shale gas resources. Uncertainties regarding the impact of its development on communities and the environment pose potential risks that the public may find unacceptable. The uncertainties, and therefore risks, can be reduced through a coordinated research effort focused on the unique BC context. Rising to meet these challenges will require a more detailed accounting of existing knowledge gaps and addressing these with science-based solutions to minimize and mitigate impacts, while also building public confidence. With the industry currently in a subdued state, but with prospects of new liquefied natural gas (LNG) projects on the horizon (e.g. LNG Canada, Woodfibre LNG), now is the time to proactively address these technical challenges before the industry ramps up to planned production levels. Regulators can use the research findings to inform the regulatory framework that protects the environment without unnecessarily encumbering development.

BC would benefit from a more formal partnership between university researchers, industry, and provincial regulators, for example, through a research institute on unconventional oil and gas research, to advance research on various topics related to hydraulic fracturing. The Pacific Institute for Climate Solutions (PICS) is one specific example. The Panel also recognizes that it is critical to include Treaty 8 First Nations and local community stakeholders in such a partnership. At the "Shale Gas and LNG Research Roundtable", hosted at UBC in November 2014, more than 70 industry and government representatives expressed support for collaborative research with BC universities including sharing essential data. Doing so would allow the research partnership to conduct innovative research and deliver the findings with transparency, and with best practice guidelines that are attuned to the technical challenges being faced as well as public expectations, while advancing knowledge for improved resource utilization and environmental risk minimization.

BC universities have played a key role in the development, growth, and resource stewardship of the province's mining and forestry resource industries. Similar opportunities present themselves to build capacity for the unconventional gas industry, not only in terms of research innovation directed at reducing environmental impacts, but also in advanced training, community engagement, and stewardship of an important provincial resource (Figure 37). BC universities have an extensive track record of advanced training and mentorship delivered by international leaders in their fields. The Hudson's Hope Field Research Station investigating natural gas migration and interactions in shallow aquifers is a prime example.

Figure 37. Regulatory requirements are a minimum — public expectations are higher. University research promotes best practices that are attuned to the technical challenges being faced by BC's unconventional gas industry and public expectations.

One avenue for a strategic research partnership is to develop a series of long-term field-scale experiments, monitoring green-field baseline conditions, and tracking their evolution through development, early production, and mature operations. Field-scale experiments afford the unique opportunity for testing and developing new technologies, enabling improved understanding of pre-existing ground conditions, and their response to hydraulic fracturing and resource extraction.

The timely questions to be addressed by such a research partnership will expose BC students to cutting-edge research and provide practical learning experiences. Their training will involve developing skills and expert-level knowledge of both the state-of-practice and state-of-the-art in shale gas extraction and environmental mitigation practices. These skill sets are in high demand and are of strategic importance for securing the competitiveness of the province's industry and export market.

A formal research partnership would also contribute towards First Nations and local community engagement. Polls[88] indicate that the public recognizes the importance of the energy sector to the economy, but many feel they do not have a good understanding of the issues. An informed public is critical for the long-term development and management of BC's vast unconventional gas resources. University researchers poll highest[89] with respect to public trust and are well-positioned to engage the public in an open dialogue. A "By British Columbia for British Columbia" research network would be well placed to foster relationships between regulator, industry, First Nations, and the public. Ultimately, best-practice regulations founded on a body of peer-reviewed science will provide confidence to the public that the province's resources are being developed responsibly.

The allocation of long-term stable funding to target step-change innovation will serve as an incentive to attract top BC researchers. Such an investment would build research capacity and training specific to the province's unconventional gas development needs, as well as to facilitate collaborations with complementary non-university research organizations. A partnership with Geoscience BC, for example, would be especially attractive given its expertise in collecting and managing data that are of value to land- and water-use decision-making related to shale gas development. In this sense, a research partnership would add capacity to maximize the value and use of industry and government collected data to the decisions chain.

Together, partnerships can be sought between provincial, federal, and industry stakeholders to facilitate the vision of developing multidisciplinary collaborations linking BC universities, building research capacity, and securing the training and knowledge-based capital required for the ongoing sustainable development of BC's unconventional gas resources.

[88] Sector importance to Canadian economy: https://www.cbc.ca/news/business/energy-sector-key-to-economy-poll-suggests-1.2436431

[89] Energy literacy and trustworthiness survey: https://www.policyschool.ca/wp-content/uploads/2016/03/energy-literacy-survey.pdf

9. Concluding Comments

To the best of its ability, the Panel carried out this scientific review of hydraulic fracturing in BC with due diligence and respect for the opinions voiced by all participants in the review process. The Panel did not censor concerns raised. While some evidence may not be referred to explicitly in this report, all evidence presented to the Panel was considered. The Panel also considered evidence in various published and unpublished papers, reports, theses, and webpages; the Panel members did not carry out independent research.

Two questions were asked of the Panel.

> Question #1: *Does BC's regulatory framework adequately manage for potential risks or impacts to safety and the environment that may result from the practice of hydraulic fracturing?*
>
> Question #2: *How could BC's regulatory framework be improved to better manage safety risks, risk of induced seismicity, and potential impacts to water?*

The Panel found these questions very challenging to answer for various reasons:

1. The activities associated with hydraulic fracturing are diverse (drilling, hydraulic fracturing, transport and storage of fluids, and disposal of fluids). Each activity represents a specific hazard to the environment.
2. The landscape, climate, and hydrology of NEBC are very diverse, and it is this diversity that historically allowed First Nations to enjoy this region and its resources.
3. There are other activities associated with resource development (mining, forestry), agriculture, etc. that have overprinting impacts on the environment.
4. Climate change has had and will continue to have impact on the environment.
5. There is a legacy of oil and gas production in the region that has seen significant changes in technology, and consequent changes in impact to the environment. For example, the transition to unconventional gas development and hydraulic fracturing itself has increased the water footprint and necessitated disposal of wastewater in unprecedented amounts. At the same time, recent advances allowing the recycling of wastewater for hydraulic fracturing has quickly, and significantly, reduced fresh water needs.
6. Throughout the history of oil and gas development in NEBC, various acts and associated regulations have changed, most notably (and recently) with the introduction of the Water Sustainability Act.
7. The very rapid development of shale gas in NEBC has made it difficult to assure that risks are being adequately managed at every step.

As mentioned at the outset of this report, the Panel could not quantify risk because there are too few data to assess risk. As such, to the best of its ability the Panel addressed the potential risks to human health, safety, and the environment. Throughout this report, the Panel has made recommendations specific to each activity/topic, and chose not to summarize these recommendations here. The recommendations are varied and often specific, but in some cases are not precise and speak to broader issues that require more thought on the part of government.

It is the view of the Panel that the current regulations under many acts appear to be robust, as suggested by previous reviews of the regulatory and policy framework; however, insufficient evidence was provided to the Panel to assess the degree of compliance and enforcement of regulations. One of the challenges with the current, generally non-prescriptive (i.e. objectives based) regulatory regime, is that most of the details for environmental protection are not transparent; rather they are embedded within various permitting processes or industry best practices or guidance documents. This is particularly problematic when there is shared regulatory responsibility, for example, concerning dams, spills and leaks, and disposal wells. Both BCOGC and ENV can issue permits, each with requirements, but the regulatory oversight is less clear. From a public perception perspective, the various activities associated with hydraulic fracturing appear to be unregulated, and this leads to fear and mistrust of the regulators. There are clear advantages to having a single window regulator for the oil and gas industry (e.g. to issue water permits, and to monitor and enforce oil and gas industry compliance with relevant environmental laws); however, this model comes at a cost in terms of public confidence. Certainly, aspects of the current shared regulatory responsibility (in regard to the construction of dams and sales of water to industry by private landowners) have led to unresolved problems.

Finally, the Panel is also concerned about legacy sites, and what could become legacy sites, if there is a downturn in gas development. One large industry operator stated "*they have lots of plans around reclamation of sites that are no longer used, but no produced water pits have been decommissioned yet*." This appears to be the case with most operators – they are waiting to decommission sites. Legacy site cleanup could become a significant financial burden to the people of BC.

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Appendix A: Panel Members and Advisor Biographies

Dr. Diana M. Allen, Ph.D., P.Geo.

Dr. Diana Allen (Ph.D. 1996, Carleton University) is a Professor in the Department of Earth Sciences at Simon Fraser University. Her research focuses broadly on water security, spanning the development of risk assessment methodologies to understanding and projecting the potential impacts of climate change on water resources. As a hydrogeologist, Dr. Allen conducts field- and numerical modelling-based research that aims to link hydrological and hydrogeological processes in diverse geological settings. She has conducted research in different regions of British Columbia, including the Gulf Islands, the Fraser Valley, the Okanagan, south-central BC, and Northeast BC, as well as in other countries. Dr. Allen has led several projects in Northeast BC that encompass the assessment of risk to shallow groundwater, the groundwater potential of buried valley aquifers, the migration of saline wastewater during deep disposal, and the sustainability of surface water under scenarios of increased demand and climate change.

Dr. Allen is a registered professional geoscientist in British Columbia and has published over 200 technical papers and report. She was the 2013 winner of the C.J. Westerman Award by Engineers and Geoscientists BC, and the 2015 winner of the Robert N. Farvolden Award by the Canadian National Chapter of the International Association of Hydrogeologists. Dr. Allen also served as Co-Editor of the Canadian Water Resources Journal for 6 years, and was a member of the Province of BC Ground Water Advisory Board from 2002 to 2010. She is currently the President of the Canadian National Chapter of the International Association of Hydrogeologists, and the Group Chair for Geosciences for the Natural Sciences and Engineering Research Council of Canada (NSERC).

Dr. Erik Eberhardt, Ph.D., P.Eng.

Dr. Erik Eberhardt (Ph.D. 1998, University of Saskatchewan) is a Professor of Rock Mechanics and Rock Engineering, and the Director of the Geological Engineering program at the University of British Columbia. His research focuses on the integration and advancement of field geology, innovative monitoring, experimental rock mechanics, and state-of-the-art numerical modelling applied to geological hazard problems encountered in deep mining, unconventional gas, and rock slope engineering projects. His research is driven by a recognition that the tools frequently used in assessing risk are often descriptive and qualitative, and that there is a need to better understand the underlying mechanisms responsible for complex rock mass responses to engineering activities.

Dr. Eberhardt is a registered professional engineer in British Columbia and consults on international projects in North and South America, Europe, and Asia. He has published over 200 technical papers, and was the 2013 recipient of the John A. Franklin Award for outstanding technical contributions to rock mechanics and rock engineering, and 2017 recipient of the

Thomas Roy Award for outstanding contributions to the field of Engineering Geology in Canada.

Dr. Amanda Bustin, Ph.D.

Dr. Amanda Bustin (Ph.D. 2006, University of Victoria) is a Research Associate at the University of British Columbia and the President of Bustin Earth Science Consultants. She is currently working as a researcher and professional consultant on a variety of unconventional gas projects with the main focus on induced seismicity and reservoir development. Dr. Bustin has broad experience in reservoir fluid evaluation including extraction, injection, storage, and disposal. Her expertise comprises induced and natural seismicity, unconventional reservoir modelling, geophysical analyses and interpretation, geomechanics, petrophysics, field work and laboratory analysis, reservoir completion and production engineering, and hydrogeomechanical modelling. She has worked on a diverse range of projects including plate tectonics and natural seismicity; reservoir assessment; complex reservoir modelling including detailed parametric analyses, comingled production, impact of hydraulic fracturing, multilateral well pads, and field-scale simulations; CO2 capture and storage; nitrogen enhanced coalbed methane production; methane clathrate hydrates; and quantification of slip due to fluid injection from hydro-geomechanical modelling. Her current research at the University of British Columbia is focused on monitoring, risk assessment, management, and mitigation of induced seismicity due to fluid injection related to natural resource activities in western Canada. This research involves the integration of field studies, laboratory analysis, and numerical simulations. She has currently deployed a seismic sensor network in western Canada that monitors hydraulic fracturing, fluid disposal, and storage.

Dr. Bustin's professional experience over the last 15 years has included working with a variety of small and large petroleum and environmental companies as a technical advisor providing engineering and geophysics oversight and analysis on fluid extraction, storage and disposal projects. She has experience in most major basins in North American and has worked broadly internationally on diverse projects. She has been responsible for or worked as a team member on all phases of reservoir development including drilling, completion, production, economics, and environmental assessment as well as the optimisation of production and disposal.

Advisor to the Panel: Nalaine Morin

Nalaine Morin is nationally recognized for her work in environmental assessment. She has led and managed the environmental reviews of several large resource development projects on behalf of First Nations. Her deep technical background in both mining and environmental assessment processes combined with being of Tahltan descent has enabled her to understand and to identify methods for the connection and support of both First Nation traditional knowledge and western science in a way that bridges cultural understanding on both sides. Ms. Morin provides services in technical review, regulatory support, negotiations, community consultation and environmental resource management. In 2006, Ms. Morin helped establish the Tahltan Heritage Resources Environmental Assessment Team (THREAT) on behalf of the

Tahltan Nation. THREAT is an innovative team that incorporates the expertise of the Tahltan people with Western science. As the lead manager of THREAT, she has supported the Tahltan Nation to navigate the environmental assessment processes of several large-scale resource projects including mines, run-of-river hydro projects and transmission lines. Ms. Morin has gained a national reputation for effectively managing complicated resource project issues in a cross cultural setting. Many of the innovative processes she has helped develop have been subsequently adopted for use at the Provincial level.

Ms. Morin works with First Nations across Canada on projects as varied as mining, pipelines and highway infrastructure. In 2009, her expertise was recognized by the Canadian Environmental Assessment Agency when she was selected as a panel member for the review of a major mining project in BC. She has been asked to speak at several conferences both provincially and nationally. In 2013, she shared a keynote address discussing impact assessment at the International Association of Impact Assessment conference and was a featured speaker at the Prospectors and Developers Association of Canada conference. Ms. Morin holds a Bachelor of Applied Science degree from the University of British Columbia and a Mechanical Engineering Technology Diploma from the British Columbia Institute of Technology. She also holds certification as an Environmental Professional, certified by the Canadian Environmental Certification Approvals Board.

Appendix B: Schedule of the Expert Presenters to the Panel

May 14 and 18, 2018			
Presenter(s)	**Presentation Title**	**Association**	**Area of Expertise**
Richard Slocomb, Kevin Parsonage, Ron Stefik	BC Oil and Gas Commission Regulation of Hydraulic Fracturing	BC Oil and Gas Commission	Regulatory
Ken Paulson, Stuart Venables, Jeff Johnson, Michelle Gaucher	BC Oil and Gas Commission Regulation of Induced Seismicity	BC Oil and Gas Commission	Regulatory
James O'Hanley, Laurie Welch, Sean Curry, Suzan Lapp	BC Oil and Gas Commission Regulation of Water Associated with Hydraulic Fracturing	BC Oil and Gas Commission	Regulatory
Devon Aaroe	Water Resource Manager	City of Dawson Creek	Water Management
James O'Hanley, Sarah Dickinson	Permitting and Consultation	BC Oil and Gas Commission	Regulatory

May 17, 2018 Full Day Session Treaty 8 First Nations	
Attendees	**Representing**
Jim Webb, Policy Advisor	West Moberly First Nation
Cec Heron, Internal Lands Manager	Doig River First Nation
Roslyn Notseta, Lands Manager	Halfway River First Nation
Kara Green, Senior Environmental Scientist	Halfway River First Nation
Bernice Li	Halfway River First Nation

May 17, 2018 Full Day Session Treaty 8 First Nations	
Attendees	**Representing**
Cynthia Burke, Lands Management	Fort Nelson First Nation
Ashley Watson	Saulteau First Nation
Dr. Gilles Wendling, Hydrogeologist	Treaty 8 Tribal Association
Nalaine Morin	Advisor to the Panel
Richard Eaton, Berlineaton	Facilitator
Kaitlin Klimosko, Berlineaton	Facilitator support

May 28, 2018			
Presenter(s)	**Presentation Title**	**Association**	**Area of Expertise**
Christine Rivard, PhD, Research Scientist	Investigation of potential upward fluid migration pathways in 2 study areas hosting unconventional hydrocarbon reservoirs in Eastern Canada	Natural Resources Canada/Geological Survey of Canada	Industry Challenges/Hydro-geology
Chelton van Geloven, R.P.F., Source Water Protection Hydrologist	Surface Water Quantity in NEBC	B.C. Ministry of Forests, Lands and Natural Resource Operations and Rural Development	Ground Water, water quantity
Suzan Lapp, PhD, PGeo, PAg Hydrologist	Surface Water Quantity	BC Oil and Gas Commission	Surface Water hydrology, NEWT
Laurie Welch, Ph.D., P.Geo. Hydrogeologist	Groundwater, Hydraulic Fracturing, Regulation, and Research	BC Oil and Gas Commission	Hydrogeology NEBC
Devin Scheck, P.Ag. Supervisor, Environmental Management	Wastewater Management	BC Oil and Gas Commission	Water & Waste Water Management

May 28, 2018			
Presenter(s)	**Presentation Title**	**Association**	**Area of Expertise**
Alex Bevington, Research Earth Scientist	Detection of Constructed Water Bodies using Free Optical Satellite Imagery, Northeast BC	B.C. Ministry of Forests, Lands and Natural Resource Operations and Rural Development	Dugouts
Jun Yin, Ph.D., P. Geo, Regional Hydrogeologist	Aquifer Characterization Projects in Northeast BC	B.C. Ministry of Forests, Lands and Natural Resource Operations and Rural Development	Hydrogeology NEBC

May 29, 2018			
Attendees	**Presentation Title**	**Association**	**Area of Expertise**
Deanna Cottrell Water & Groundwater Risk Subject Matter Expert	Subsurface Water Quality Research	Shell Canada Ltd.	Hydrogeology, water initiatives
James Armstrong, PhD, Water Stewardship Advisor	Encana Water Management	Encana Corp	Ground water contaminates
Donald B. Davies, Ph.D., DABT Toxicology Consultant	Hydraulic Fracturing … a Toxicologist's perspective	Intrinsic	Toxicology
Dr. Jon Fennell, M.Sc., Ph.D., P.Geo., Consultant	Hydraulic fracturing review: Water Quality	Integrated Sustainability	Ground Water contaminates
Stephanie Strachan, Environmental Studies Scientist and Ayisha Yeow, Senior Environmental Monitoring Scientist	Water quality and ecosystem health Monitoring in Petitot River and Surrounding watersheds: A review of the baseline study conducted from 2012 to 2014 and current activities to 2018	Environment and Climate Change Canada	Surface Water quality, CABIN model

May 30, 2018			
Attendees	**Presentation Title**	**Association**	**Area of Expertise**
Shawn Maxwell, PhD, Microseismicity	Hydraulic Fracture Induced Seismicity	Itasca Microseismic	Consultant/industry expert - Seismicity
John Nieto, Chief Technology Officer	Managing Induced seismicity in Canbriam's Altares Field	Canbriam Energy	Operator – Induced Seismicity
David Miller, P.Geoph. Team Lead, Geophysics	Induced Seismicity	Progress Energy	Operator – Induced Seismicity
Neil Orr, Chief Geophysicist and Andy Gamp, P.Geoph., District Geophysicist.	Presentation to Scientific Hydraulic Fracturing Review Panel	Canadian Natural Resources Limited	Operator – Induced Seismicity
Honn Kao, PhD.,Research Scientist Geological Survey of Canada	Injection-Induced Seismicity in NE BC	Natural Resources Canada	Federal Government researcher- seismicity
David W. Eaton, PhD Professor, Department of Geoscience *NSERC/Chevron Industrial Research Chair in Microseismic System Dynamics*	Hydraulic Fracturing and Induced Seismicity	University of Calgary	Induced Seismicity
Stu Venables, P.Geo ; Dr. Alireza Mahani, P.Geo ; Jeff Johnson, P.Geo	Scientific Hydraulic Fracturing Review Panel: Induced Seismicity Technical Review	Geoscience BC, BC Oil and Gas Commission	Induced Seismicity

May 31, 2018			
Attendees	**Presentation Title**	**Association**	**Area of Expertise**
Maurice B Dusseault University of Waterloo	What are the Real Risks in Shale Gas Development in BC?	University of Waterloo	Industry Challenges
Jeff Willick C.E.T. Manager, Abandonment Operations	Scientific Hydraulic Fracturing Review Panel Wellbore Integrity	Canadian Natural Resources Limited CNRL	Gas migration
Peter Pokorny VP, Operational Policy & Environment	Liability Management Presentation to the Scientific Hydraulic Fracturing Review Panel	BC Oil and Gas Commission	Well Remediation/ Liability
David J Browne PEng Director, Intellectual Property and Public Affairs	Fugitive gas emissions from well drilling and completions (well construction and cement integrity)	Trican	Well construction and Cement
Ian Frigaard, Ph.D.	Hydraulic Fracturing and Primary Cementing	University of British Columbia	Cement
Professor Roger Beckie and Dr. Aaron Cahill	BC Scientific Hydraulic Fracturing Review Panel Expert Statement on Fugitive Gas	University of British Columbia	Researchers Gas Migration
Kevin Parsonage, M.A.Sc., P.Eng.	Methane Emissions Presentation to the Hydraulic Fracturing Scientific Review Panel	BC Oil and Gas Commission	Gas Migration and fugitives

June 25, 2018			
Attendees	**Presentation Title**	**Association**	**Area of Expertise**
Victor Shopland General Manager of Integrated Services	n/a	City of Fort St. John	City Water Manager, Regional Watersheds
Michael Freer, Treaty 8 Tribal Association and Dr. Gilles Wendling, GW Solutions	Scientific Hydraulic Fracturing Review Panel T8TA- Concerns	Treaty 8 Tribal Association/ GW Solutions	Lands and Resource Manager
Kara Green Senior Environmental Scientist / Project Manager	Hydraulic Fracturing Review Panel	Ecora Engineering & Resource Group /Halfway River First Nations	
Ben Parfitt	Presentation to the Scientific Hydraulic Fracturing Review Panel	Canadian Centre for Policy Alternatives	Natural Resource Policy Analyst

June 26, 2018			
Attendees	**Presentation Title**	**Association**	**Area of Expertise**
Julian Munoz C.E.T., Team Lead, Production Engineering	Water Management	Progress Energy	Water Management
Stuart Valentini, P.Eng., Manager, Drilling & Completions Engineering	Wellbore Integrity	Progress Energy	Drilling Engineer, Cementing

July 10, 2018			
Attendees	**Presentation Title**	**Association**	**Area of Expertise**
Ed Hoffman, Regional Director, Environmental Protection Division	Produced Water Management	Ministry of Environment and Climate Change Strategy	Water-waste permitting
Carlos J. Salas, MSc. P. Geo.	Enabling responsible Oil & Gas management through credible, unbiased earth science	Geoscience BC	BC Research updates and needs
Tim Lambert, PhD. Executive Director, Health Protection	Scientific Hydraulic Fracturing Review Panel Session NE Oil and Gas Human Health Risk Assessment	Ministry of Health	Human Health Risk Assessment
Ali Azizishairazi, Senior Water Quality Guidelines Specialist	Water quality management tools: potential application in managing Hydraulic Fracturing Fluids?	Ministry of Environment and Climate Change Strategy Watershed Science Branch	Water Quality BC
Chris Pasztor, Director Resource Development	A Regional Strategic Environmental Assessment Update	Ministry of Energy, Mines and Petroleum Resources	Regional Strategic Environmental Assessment (RSEA)
Ian Bruce, Director of science & policy /John Werring,	Presentation to B.C.'s Hydraulic Fracturing Review Panel/ DSF Research into Hydraulic Fracturing in B.C.	David Suzuki Foundation	NE BC –SCVF/ gas emissions research

July 11, 2018			
Attendees	**Presentation Title**	**Association**	**Area of Expertise**
Deanna Cottrell	Water Management Overview Shell in NEBC	Shell Canada (Shell)	Shell Water Projects
Max Kniewasser Brianne Riehl	Potential Risks of Hydraulic Fracturing in B.C. Presentation to the Scientific Review Panel	Pembina Institute	Water and Health Researchers

July 11, 2018			
Attendees	**Presentation Title**	**Association**	**Area of Expertise**
Rick Kessy, Chief Operating Officer Matthew Ng, Senior Geophysicist Jim Reimer, VP Geoscience & Technology (retired)	Presentation to the British Columbia Scientific Hydraulic Fracturing Review Panel	Painted Pony Energy Ltd.	Unconventional resource development – mid-size company
Dr. Mark D. Zoback Benjamin M. Page Professor of Geophysics Director, Stanford Natural Gas Initiative Co-Director, Stanford Center for Induced and Triggered Seismicity	Induced Seismicity Associated with Unconventional Oil and Gas Development	Stanford University	Induced Seismicity from Injection
Dan Allan and Brad Hayes	State of hydraulic fracturing science BC Scientific Hydraulic Fracturing Review Panel	Canadian Society for Unconventional Resources	Hydraulic Fracturing Research
Tara Payment, M.Sc Bill Westwood, P. Geoph.	1. Presentation to B.C. Hydraulic Fracturing Review Panel- Water 2. Presentation to B.C. Hydraulic Fracturing Review Panel- Induced Seismicity	Canadian Association of Petroleum Producers	Water Management Induced Seismicity

Fall Sessions, 2018			
Attendees	**Presentation Title**	**Association**	**Area of Expertise**
Kofi O. Addo	Presentation to the Scientific Hydraulic Fracturing Review Panel	BC Hydro	Seismicity
Markus Schnorbus Lead Hydrologic Impacts	Climate Change and Surface Water Resources Northeastern British Columbia	Pacific Climate Impacts Consortium, University of Victoria	Hydrologic Impacts Climate Change

Appendix C: List of Relevant Legislation and Regulations

Legislation and Regulations	Description
OIL AND GAS ACTIVITIES ACT (OGAA)	OGAA regulates oil and gas and related activities in B.C., including wells, facilities, oil refineries, natural gas processing plants, pipelines and oil and gas roads, through permits, authorizations, orders and regulations.
Oil and Gas Activities Act Regulations	
Administrative Penalties Regulation	Contains the maximum administrative or monetary penalties that can be levied for contraventions of the requirements in the Act and Regulations.
Consultation & Notification Regulation	Outlines requirements for consultation and engagement with landowners and rights holders that must occur before a permit application and/or amendment is submitted to the OGC. Link to guidance. **Note:** Refer to Appendix 2 of the amended Emergency Management Regulation for recent changes to the Consultation and Notification Regulation.
Drilling & Production Regulation	Regulates drilling, completion and production operations. Links to guidance available for wells, cores, hydraulic fracturing, storage reservoirs and oil and gas and water production.
Emergency Management Regulation	Regulates the planning for emergencies, with an all-hazards approach, and for the initiation of emergency response arising from oil and gas activity. Link to guidance.
Environmental Protection and Management Regulation	Sets out government's environmental objectives for oil and gas activities to enable environmental protection during the lifecycle of an oil and gas activity. Links to EPM Guideline and other remediation, reclamation and restoration guidance
Fee, Levy and Security Regulation	Sets out the fees, levies and security payable in respect of oil and gas permits and activities.
Geophysical Exploration Regulation	Outlines the requirements for geophysical exploration activities.

Legislation and Regulations	Description
Oil and Gas Activities Act General Regulation	Regulates permit expiration, special projects, release of information, surveys, taxation, etc.
Oil and Gas Road Regulation	Regulates construction, maintenance, use and deactivation of oil and gas roads. Link to guidance.
Pipeline Regulation	Regulates construction, maintenance, use and deactivation of pipelines. Link to guidance.
Pipeline Crossings Regulation	Regulates distances for working near and for crossing a pipeline and all associated costs.
Service Regulation	Sets out the methods of delivery for documents and notices.
Other Provincial Legislation	Carrying out oil and gas and related activities may require additional approvals from other regulators or create obligations under other statutes.
AGRICULTURAL LAND COMMISSION ACT	Agreement with the Commission granting powers to the Commission to decide on applications for permission for non-farm use of identified ALR lands for oil and gas activities and ancillary activities. Link to guidance.
ENVIRONMENTAL ASSESSMENT ACT (EAA)	Regulates B.C. environmental assessment processes for reviewable projects.
Reviewable Projects Regulation (RPR)	Under Part 5 of the RPR, a Freshwater Storage Site that is a dam with a berm height that equals or exceeds 15 metres is a reviewable project under the EAA. The operator must contact the Environmental Assessment Office to determine whether an Environmental Assessment Certificate is required.
ENVIRONMENTAL MANAGEMENT ACT	
Contaminated Sites Regulation	Provides numerical and risk-based standards to determine when cleanup is needed and satisfactorily completed.
Hazardous Waste Regulation	Regulates hazardous waste which may include oil and gas waste. Includes requirements for the storage, transport, treatment and disposal of hazardous waste.
Oil and Gas Waste Regulation	Regulates oil and gas waste permits.

Legislation and Regulations	**Description**
Spill Reporting Regulation	Outlines that any release of substances must be reported immediately if (a) the releases of a substance may cause, is causing or has caused an adverse effect to the water, environment, human health or safety, or property, (b) if the spill amount is equal to or greater than the minimum quantity set by the Spill Reporting Regulation, and (c) spills of any size that occur near or on water.
Waste Discharge Regulation	Oil and gas industry is a prescribed industry under the Waste Discharge Regulation.
FOREST ACT	Regulates oil and gas Master Licences to Cut, cutting permits and use of forestry roads.
GREENHOUSE GAS INDUSTRIAL REPORTING AND CONTROL ACT	Enables performance standards to be set for industrial facilities or sectors by listing them within a Schedule to the Act and provides authority to make regulations.
Greenhouse Gas Emission Reporting Regulation	Requires that industrial operations that emit over 10,000 carbon dioxide equivalent tonnes per year (tCO_2e) report their GHG pollution each year. Operations emitting over 25,000 tCO_2e are required to have their emission reports independently verified.
Greenhouse Gas Emission Administrative Penalties and Appeals Regulation	Establishes the process for when, how much, and under what conditions administrative penalties may be levied for non-compliance with the act or regulations
HERITAGE CONSERVATION ACT	Regulates cultural and heritage (archaeology) sites in B.C.
LAND ACT	Regulates Crown land licences of occupation, statutory right of ways and rents. Link to guidance.
MINES ACT	
Health, Safety and Reclamation Code for Mines in British Columbia	Regulates Mines Act permits for oil and gas aggregate extraction. Link to guidance
PETROLEUM AND NATURAL GAS ACT	
Petroleum and Natural Gas General Regulation	Regulates subsurface tenures and royalties for oil and gas.
Surface Lease Regulation	Sets out terms and conditions of surface leases.

Legislation and Regulations	**Description**
WATER SUSTAINABILITY ACT	Regulates water use, wells, dams, ground water protection, crossings and works in and about a stream that are not regulated by OGAA. Link to guidance.
Dam Safety Regulation	Reduces risk to public safety, the environment or property due to dam failure
Groundwater Protection Regulation	Ensures that activities related to water wells and groundwater is performed in an environmentally safe manner.
Water Sustainability Regulation	Addresses application requirements for water use or making changes to a stream
Water Sustainability Fees, Rentals and Charges Tariff Regulation	Specifies the water-related fees for all water uses.
WORKERS COMPENSATION ACT	Describes safe work procedures for workers. Part 3 of the Workers Compensation Act addresses matters including accident reporting, investigations, enforcement, offences, administrative procedures, and regulation-making authority.
Occupational Health and Safety Regulation (OHSR)	OHSR contains legal requirements that must be met by all workplaces under the inspectional jurisdiction of WorkSafeBC, including the oil and gas industry. The purpose of the OHSR is to promote occupational health and safety and to protect workers and other persons present at workplaces from work-related risks to their health, safety, and well-being.
WEED CONTROL ACT	Contains requirements to control noxious weeds.
Weed Control Regulation	
WILDLIFE ACT	Details the provincial regulatory requirements related to wildlife
Federal Statutes that may apply	
CANADIAN NUCLEAR SAFETY ACT	Defines “nuclear substance” which includes naturally occurring radioactive materials (NORM)
Packaging and Transport of Nuclear Substances Regulation	NORMs are subject to 2 sections of the regulation that describe when a licence is required to transport

Legislation and Regulations	Description
HAZARDOUS MATERIALS INFORMATION REVIEW ACT	Outlines conditions for exemption from the requirement to disclose information under the provisions of the *Hazardous Products Act*, if the supplier considers it to be confidential business information.
Hazardous Materials Information Review Regulation	
HAZARDOUS PRODUCTS ACT	Requires suppliers of hazardous products to disclose the hazards associated with their products via product labels and Safety Data Sheets as a condition of sale and importation for workplace use .
INDIAN OIL AND GAS ACT	Allows the federal government to regulates on-reserve oil and gas activities .
FIRST NATION COMMERCIAL AND INDUSTRIAL DEVELOPMENT ACT	Allows the federal government to produce regulations for complex commercial and industrial development projects on reserves
MIGRATORY BIRDS CONVENTION ACT	Contains requirements to protect migratory birds, their eggs, and their nests and prohibits the dumping of substances harmful to birds in waters or areas frequented by them.
Migratory Birds Regulation	
SPECIES AT RISK ACT	The purposes of the Species at Risk Act are to prevent wildlife species in Canada from disappearing, to provide for the recovery of wildlife species and to manage species of special concern to prevent them from becoming endangered or threatened.
TRANSPORTATION OF DANGEROUS GOODS ACT	The purpose of the **Transportation of Dangerous Goods Act** and Regulations is to promote public safety when **dangerous goods** are being handled, offered for **transport** or transported by road, rail, air, or water (marine).
Transportation of Dangerous Goods Regulation	